

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1063 SCOMM 28: JOINT GAS PIPELINE COMMITTEE, 1981-82

Despite the existing availability of surplus gas in Canada, 1980 gas exports to the U.S. plummeted 17 percent from 1979 levels, or from 1,001 bcf to 833 bcf. This decline was due to a number of interrelated factors, including economic recession effects in regions traditionally dependent on Canadian gas, an abundance of residual fuel oil and increased availability of L48 pipeline gas in those regions and, most importantly, an increase in the Canadian gas export price from \$3.45/mcf at the beginning of 1980 to \$4.47/mcf by April 1, 1980. Canada has announced a gas export pricing policy based on "value substitution" or price linkage with imported Canadian crude oil. However, the decline in Canadian gas export demand has ameliorated the implementation of this policy (i.e., a planned October 1980 export gas price increase was delayed until April 1, 1981, and was then posted at \$4.94/mcf--below the possible crude oil-linked formula price). Over the long-term, and as traditional U.S. markets for Canadian gas strengthen, we expect Canadian gas export prices to escalate in step with world oil prices.

Mexican Gas Imports

Mexico's successes in gas and oil exploration in the past decade have resulted in that country's recent re-emergence as a major energy exporter. Mexican export gas began flowing in January 1980, at the rate of 300 million cubic feet per day (0.1 tcf/year) under a contract with a six-company U.S. consortium called Border Gas, Inc. Moreover, Jensen Associates projects U.S. imports of Mexican gas to increase to 0.4 tcf in 1985 and to reach 0.7 tcf by 1990.

Mexico's proved gas reserves are now estimated at over 80 tcf, with an additional 72 tcf of probable reserves. Most of Mexico's gas production is associated or co-produced with crude oil; hence, as Mexico has increased its crude production levels, gas production has similarly increased. For example, between 1978 and 1979, gas production increased 14 percent as a result of Mexico's attainment of crude oil production goals. And while Mexico is engaged in major efforts to reduce gas flaring through reinjection of gas into reservoirs and through utilization of gas domestically, we expect that the overall availability of gas coupled with the favorable economics of pipeline gas flows will mean increased gas exports to the U.S. by the mid 1980s. Existing pipeline facilities linking Mexico's gas producing areas to U.S. markets will need to be expanded to accommodate higher export levels; however, a large-diameter branch pipeline to the U.S. was originally envisioned as part of Mexico's developing gas grid network and we would anticipate construction of such a pipeline by the mid 1980s.

Although Mexico has announced an energy policy limiting gas exports to present levels, we expect that this posture will be ameliorated over the longer-term by general gas availability, gas export revenue considerations and physical limitations on utilizing the gas internally.

Mexico's current gas export price is tied directly to the prices of five key world export crudes with a contract provision permitting price

parity with the Canadian export gas prices, should the latter be higher. In our forecast, we have assumed price parity with Canadian gas.

Liquefied Natural Gas (LNG) Imports

The optimistic outlook of the mid 1970s for large-scale movements of LNG to the U.S. by the early 1980s has gradually succumbed to the realities of major obstacles to such projects. Public concerns about the safety of LNG shipments, local objections to proposed terminal sites, government fears of gas over-dependence on foreign sources, doubts about the pipelines' needs for LNG supplemental gas, and U.S. government policy preferences for other supplemental gas sources have all played a part in reducing many LNG import proposals to little more than hollow possibilities. Of some 14 often-cited "probable and possible" U.S. LNG projects of the mid 1970s only two reached operational status (an expanded Distrigas project using facilities already in operation by 1972 and El Paso I), with a third project (Trunkline LNG) scheduled for start-up in August of 1981. All are based on Algerian-source gas.

The pricing of LNG has always been a difficult issue to resolve because of the massive investments required of both exporter and importer and the disparate government perspectives of LNG producing and consuming countries on the value of the gas to the user. Recent producing country pressure for f.o.b. gas pricing parity with crude oil has added to the difficulty of negotiating an LNG price acceptable to all parties.

LNG deliveries under the El Paso I project have been disrupted since April 1980 because of the gas pricing issue, although volumes under the much smaller Distrigas project have continued to flow. Despite the announced financial write-off by El Paso LNG of some \$375 million of its LNG investment (after termination of U.S.-Algerian government pricing talks in February 1981), we believe there is a reasonable likelihood that deliveries--possibly at reduced levels--under this project will resume. The U.S. pipeline purchasers of El Paso I LNG are making efforts to negotiate directly with Algeria on the gas pricing issue and, in addition, the LNG tankers dedicated to this project have not yet been committed elsewhere. Thus, our 1985 supply forecast includes a contribution of 0.5 tcf from the El Paso, Distrigas and Trunkline projects.

Currently, four other LNG projects--Pac Indonesia, Pac Alaska, Nigeria Bonny, and Trinidad/Tobago--are in varying stages of planning or regulatory approval. In our estimates, we have assumed that additional LNG volumes of 0.2 tcf will come on stream in the latter half of the 1980s. We assume that any additional volumes, from these or other projects, will probably not be operational until after 1990.

Unconventional Production

Unconventional sources such as Devonian shales, coal seams, and tight formations are expected to make a small but measurable contribution to

total gas supplies over the forecast period. The incentive of deregulation (as of November 1, 1979) for Devonian shale gas and coal-seam gas, along with allowable higher prices for tight gas, should stimulate production from these sources.

Devonian shales extend geographically over one-fourth of the North American continent, with significant deposits in the eastern United States. Miniscule production from this source occurs presently and improvements in exploration technology, allowing better definition of the shale areas and economically producible gas zones within Devonian shales, are expected to increase gas from this source in the latter half of the 1980s.

At least one proposal to tap coal-seam methane on a commercial basis has already been submitted to the Federal Energy Regulatory Commission and gas from this source is expected to make a small contribution to total unconventional production by 1985 and thereafter.

Interest in tight formation gas has been stimulated by the establishment of a special, high-cost incentive price in the NGPA. Some 150 different areas in the U.S. are under consideration for designation as tight gas producing areas. Hydraulic fracturing techniques are currently available to tap tight gas, but according to the National Petroleum Council¹, the technological improvements required to provide their widespread routine application will possibly take 9 to 17 years of intensive research and development effort. Thus, tight gas production from massive, relatively unproductive formations of the West is not expected to become substantial until after the 1980s. Forecasts of natural gas from currently producing tight sands areas are included in the conventional production figures of Table III-1.

Gas supplies from unconventional production are expected to reach a total of 0.1 tcf per year by 1985, and 0.3 tcf by 1990. Most of this will be tight formation gas from newly developing plays.

Another unconventional gas source is geopressed brine, but apparent production costs relative to other unconventional sources suggest that measurable production from this source is unlikely before the late 1990s.

Synthetic Natural Gas (SNG)

1. Liquid feedstocks

During the past two years, the greater availability of less expensive domestically-produced and pipeline imported natural gas has greatly reduced

¹ "Tight Gas Reservoirs-Part I," Unconventional Gas Sources, NPC, December 1980.

the demand for SNG reformed from naphthas and natural gas liquid products. In 1980, SNG supply dropped to 123 bcf. The 13 SNG plants in the U.S. are capable of producing over 300 bcf per year, indicating substantial idle capacity. We expect these plants to operate primarily as peak-shaving facilities until such time that all other less expensive baseload supplies are inadequate to meet demand. Consequently, our forecasts for the years 1985 and 1990 range from a peaking use level of about 0.1 tcf per year to an all-out rate approaching 0.4 tcf per year if demand exceeds supply of all other gas supplements, including Alaskan gas and LNG imports.

2. Coal gasification

The United States is poised on the threshold of developing high-Btu coalgas as a commercial gas supplement. Although the optimism of the mid 1970s, which envisioned production from five, large, pipeline-quality coal gasification projects by 1980 and an additional eleven plants by 1985, is considerably more guarded now, start-up in this decade of the nation's first commercial coalgas plant seems likely.

Several high-Btu synthetic-natural-gas-from-coal projects are under consideration. The Great Plains Gasification Associates proposal for an initial plant output in 1984 of 125 MMcf of coalgas is most advanced and has received conditional Federal approval of plant financing loan guarantees. At least four other coalgas projects have sought loan guarantees through the Federal Synthetic Fuels Corporation, but the overall level of government financial support for coal gasification is uncertain at this time. Without such assistance, the substantial impediments of plant financing seem certain to further delay most coal gasification projects.

Our forecast for supplemental high-Btu coalgas includes a negligible contribution in 1985 and 0.2 tcf in 1990. This latter amount is equivalent to the output from two plants, each producing 250 MMcf. In actuality, we expect several smaller-sized plants to be in place by the end of the 1980s.

Alaskan Pipeline Gas

Initial deliveries of natural gas from Prudhoe Bay through the Alaskan Natural Gas Transportation System are scheduled to occur in 1987. The forecast of 0.7 tcf in 1990 represents gas deliveries to the 48 States. It excludes deliveries to Alaskan users and transmission fuel.

IV. THE DEMAND FOR NATURAL GAS

Energy prices have been a major political and economic issue during much of the last decade. Policymakers have debated whether energy prices should be allowed to increase, who should reap the benefits of any price increases, and how the burden of any increases should be distributed. Proponents of a free market system have compromised their preferences to accommodate the social welfare concerns of the market regulators. As a consequence, our current energy pricing policies may be characterized as a complex system of partially regulated prices attempting to selectively emulate a market system, while still keeping consumer prices below market clearing levels. In the course of the decade, however, energy prices have risen substantially due to the changes in international petroleum markets.

These higher prices, in conjunction with both projected and realized fuel shortages, have altered the market for all energy. This is particularly true for natural gas. Conservation has reduced the requirements for all energy, while the gas shortages of the mid 1970s--which required the expansion of alternate fuel capabilities--have increased the fuel choice options of many commercial and industrial firms. In the next decade, continued conservation and intensified interfuel competition following deregulation of natural gas will have substantial influences on the demands for natural gas.

Our demand forecast is summarized in Table IV-1. Residential and commercial demands are expected to be relatively stable over the next decade as demand from new customers is offset by conservation from existing customers. Industrial demand is expected to increase substantially as the gap between gas and oil prices widens between now and 1985, when price controls end for a large part of gas supply. This growth is strongest in the premium process and smaller boiler fuel markets in the major natural gas producing areas where the imposition of Federal price controls has re-established natural gas as the preferred industrial fuel. Subsequent to deregulation, however, the industrial market for gas is expected to contract substantially as alternate fuels become more attractive. The electric power generation demand for gas is not expected to experience the same level of growth as the industrial sector prior to 1985, but will shrink similarly following the rapid escalation in prices expected in 1985.

Residential/Commercial Demand

The rapid growth in new gas customers that prevailed in the 1960s declined appreciably in the 1970s with the advent of interstate pipeline curtailments. The restrictions on new customer additions, particularly widespread in the East, effectively removed many gas utilities as a competitive force in the new construction market. At the same time, existing residential gas customers were adjusting their consumption downward in response to the real increases in their cost of natural gas.

TABLE IV-1

LOWER 48 STATES DEMAND FOR NATURAL GAS
1979-1990
(Quadrillion Btus)^a

	Actual 1979	Forecast		
		1984	1987	1990
Residential	5.1	5.0	5.0	4.9
Commercial	2.8	2.7	2.7	2.7
Industrial	7.0	9.4	7.2	6.9
Power Generation	3.3	3.5	2.5	2.2
Other	<u>2.9</u>	<u>2.3</u>	<u>2.1</u>	<u>2.0</u>
Total Demand	21.1	22.9	19.5	18.7

^a The gas data in this chapter are all in quadrillion Btus.
The supply/demand balances in Chapters I, III and V are
all in trillion cubic feet.

Source: Jensen Associates, Inc.
Gas Requirements Agency

The effect of conservation on residential gas demand has been less pronounced than in the commercial and industrial sectors, however, because the incentives to conserve have not been as strong. Subsequent to the OPEC oil price increases in 1973, the price of all energy began to rise. Higher wellhead prices allowed by the Federal Power Commission, rapid increases in unregulated intrastate wellhead prices, the addition of relatively expensive supplemental gases and lower interstate sales volumes all contributed to the increased city gate prices for gas. These price increases were not allocated evenly among all customer classes, as shown in Table IV-2. During this period, residential gas prices actually increased less than the average city gate price, while industrial prices increased substantially more than the average city gate cost. In effect, the increases in petroleum prices elevated the threshold price at which industrial users would begin to shift to alternate fuels--principally oil--thereby allowing them to bear a greater burden of gas costs. With continued increases in natural gas costs against a background of deteriorating real petroleum prices, the ability of regulatory agencies to augment this effective subsidization of residential consumers diminished. By 1978, further wellhead gas cost increases were necessarily reflected in residential prices, although the implicit city gate cost to residential customers remained lower than that for the industrial sector. The 48 percent real increase in residential gas prices did prompt residential consumers to reduce their average normalized consumption by 12.5 percent, but both commercial and industrial conservation levels were substantially higher.

Three subsequent events have re-established the potential for further subsidization of the residential sector: the passage of the incremental pricing provision in the Natural Gas Policy Act; the rapid escalation of world oil prices following the Iranian Revolution; and the decontrol of U.S. crude prices. The collective effect of these events has been to again raise the fuel switching threshold for industrial gas customers. However, while residential natural gas prices are not expected to increase to the same degree as will other sectors, the real cost of space heating will continue to rise, prompting further residential conservation. By 1985, we project residential conservation to reach 22 percent (on a per customer basis relative to 1972) and rise to 27 percent by 1990.

Implicit in this analysis is the expectation that a substantial number of new customers will be added to the gas distribution network. Although some of these new customers will be conversions from other fuels in existing structures, new construction represents the majority of these new attachments. Because these new units are much more efficient than the average existing house--not only in the space heating requirements of the building but also in the efficiency of the heating system--their addition reduces the average usage-per-customer.

With the removal of the state moratoriums on new customer additions, the gas market share in new construction is expected to rebound from the low levels of the 1970s. In the areas of the country where electricity is the principal competitor, however, gas is not expected to always return to

TABLE IV-2

U.S. AVERAGE NATURAL GAS PRICES
1972 - 1979
(1980 dollars per million Btu)

	<u>1972</u>	<u>1979</u>	<u>1972-1979</u> <u>Increase</u>	<u>1972-1979</u> <u>% Increase</u>
U.S. Average Wellhead Price (\$ per mcf)	\$0.34	\$1.25	\$0.91	272%
U.S. Average City Gate Price	0.78	1.98	1.20	154%
U.S. Average Residential Price	2.15	3.19	1.04	48%
U.S. Average Industrial Price	0.81	2.45	1.64	202%

Source: Jensen Associates, Inc.
U.S. Department of Energy
American Gas Association

its pre-shortage market share. Between 1972 and 1979, when residential gas prices rose 48 percent in real terms, residential electricity prices only increased 14 percent in real terms. The price of electricity relative to natural gas had actually fallen by 23 percent as illustrated in Table IV-3. This trend is expected to continue throughout the forecast period. Although gas prices remain well below electricity prices, the effective heating cost of gas approaches that of electricity by the end of the decade. As a consequence, although the number of new, gas space heating customers will increase annually, the gas market share in new construction is expected to decline.

The Northeast region, where oil is the principal competing space heating fuel, is an exception. The natural gas price advantage over distillate oil that developed with the Iranian revolution is expected to be maintained throughout the decade. Following deregulation in 1985, this competitive advantage is diminished so the high level of conversions from oil to gas in existing homes tapers off, but gas does continue to capture a higher share in the new construction market.

Despite the consumer preferences for natural gas, however, natural gas distributors may become somewhat cautious about new residential connections. As gas costs continue to rise, new homes will become increasingly efficient. With very low consumption levels, the rate of return on the investment in new mains required to attach new customers may decline sufficiently to make the investment unattractive. This could be accentuated with an inverted marginal cost rate structure where negative rates of return on the residential rate base are possible. Under these circumstances, while natural gas demands would be lower than shown in Table IV-4, the effect would likely be small due to the low consumption levels in these new units.

The commercial sector's consumption patterns are more varied than those in the residential sector, but the basic changes are quite similar. Commercial conservation has been slightly higher because the incentives were greater. Absent the subsidies reaped by the residential sector, and frequently facing higher rates of return on conservation investments, the commercial sector responded more quickly to rising gas prices. However, the ultimate potential conservation in this sector is lower than the potential in the residential sector--due largely to the smaller surface areas per unit of volume in commercial buildings. For this reason, commercial consumption-per-customer is forecast to decline at a lower rate than projected for the residential sector.

The net effect of the residential and commercial customer growth and conservation are shown in Table IV-4. Overall, residential demand is projected to increase (due in large part to a substantial number of oil to gas conversions) through 1985, and then decline as conservation more than offsets the demand of new customers. For the commercial sector, demand is expected to be relatively stable throughout the forecast period.

TABLE IV-3

U.S. AVERAGE RESIDENTIAL ENERGY COSTS
(1980 dollars per million Btu)

	<u>1972</u>	<u>1979</u>	<u>Percent Change</u>
Gas	\$ 2.15	\$ 3.19	48%
Electricity	\$12.15	\$13.88	14%
Relative Prices (Ratio of Electricity to Gas Price)	5.65	4.35	(23%)

Source: Jensen Associates, Inc.
American Gas Association
Edison Electric Institute
U.S. Bureau of Labor Statistics

TABLE IV-4

RESIDENTIAL AND COMMERCIAL GAS DEMAND
1979 - 1990
(Trillion Btu)

	1979		Forecast		
	<u>Actual</u>	<u>Normalized</u>	<u>1984</u>	<u>1987</u>	<u>1990</u>
Residential	5,131	4,834	4,987	4,963	4,904
Commercial	<u>2,760</u>	<u>2,606</u>	<u>2,679</u>	<u>2,686</u>	<u>2,682</u>
Total	7,891	7,440	7,666	7,166	7,586

Source: Jensen Associates, Inc.
Gas Requirements Agency

Industrial Demands for Natural Gas

The increase in delivered price of industrial natural gas during the latter half of the 1970s (see Table IV-2) had two major effects on the markets for gas--it provided an incentive for industrial firms to conserve by improving their energy efficiency, and it reduced the industrial demand for gas in selected applications when other fuels became the lowest cost source of heat. The net effect of these two changes was to substantially shrink the overall demand for gas, so that the chronically short market of 1976 became a relatively balanced market by 1978.

The measurement of conservation is a complex exercise, in part because it has more than one definition. From an engineering viewpoint, conservation is the reduction in fuel use required to produce a particular product--either because of improved operating procedures or technological change. This is basically what the U.S. Department of Energy compiles in its voluntary industrial conservation program for which conservation (relative to 1972) is estimated at 14 percent as of 1978. However, viewed from the broader perspective of total industrial output, conservation (measured as the reduction in fuel use per unit of output) had reached 24 percent by 1978. This significantly larger estimate suggests a shift in the types of products produced, with energy intensive products declining and other products increasing.

In addition to this shrinkage of the industrial market due to conservation, the actual and anticipated gas shortages, which began with the interstate pipeline curtailments in 1971, created a more price-sensitive fuel market as alternate fuel capability was added and expanded. The large segment of the industrial fuel market that is now dual-fueled only needs to examine operating cost differentials and product quality premiums when choosing fuels. An examination of the fuel switching and market share adjustments that occurred between 1972 and 1978 shows that oil captured three-quarters of the shift (see Table IV-5). Coal usage declined despite the Federal efforts to shift industrial boilers to coal. Although the purchase price of coal is generally less than oil, the higher investment and operating costs for coal (as well as the environmental difficulties associated with coal) appear to more than offset this initial advantage. Most increases in coal use by industry are expected to be associated with new facilities because conversion of gas-fired equipment to coal is generally impractical.

The Powerplant and Industrial Fuel Use Act (FUA), passed as part of the National Energy Act in 1978, represents an effort to shift industrial and electric utility boilers from gas and oil to coal by legislative fiat rather than through the creation of economic incentives. The industrial portion of the Act is summarized below.

New Major Fuel Burning Installations (MFBI)

New MFBI boilers would be prohibited from burning oil or natural gas. Non-boiler usage at new MFBI's would be subject

TABLE IV-5

TOTAL U.S. INDUSTRIAL FUEL SWITCHING

1978

(Billion cubic feet gas equivalents)

Base Year 1972

<u>Fuel</u>	<u>Volumes</u>	<u>Percent</u>
Residual Oil	+498	+47%
Distillate Oil	+305	+29%
Refinery Gas	+209	+20%
Other	+ 59	+ 6%
Coal	- 21	- 2%
Subtotal	+1050	+100%
Natural Gas	-1050	-100%
Net Fuel Switching Between Fuels	0	0

Source: Jensen Associates, Inc.
Gas Requirements Agency
U.S. Department of Energy

to a case-by-case prohibition. Exemptions would be allowed for process use, cogeneration facilities, and for compliance with environmental laws.

Existing MFBI's

Existing MFBI's using more than 300 mcf per day must switch from oil and natural gas if they are economically and technically capable.

In our analysis we have assumed that the FUA will be strictly applied to new boilers and no new MFBI boilers will be permitted to burn natural gas. The actual effect of the legislation on the existing industrial market hinges upon the executive interpretations of the rules for exemption, which include economic, technical and environmental criteria. In the near term, the impact of the legislation is expected to be limited by the small number of gas-coal fired boilers.

The incremental pricing provisions of the NGPA attempted to provide the economic incentives for industrial boiler conversions that were lacking in the coal conversion program. However, in order to limit load shifting to petroleum products, the FERC regulations set a ceiling on industrial gas prices equivalent to the prevailing high-sulfur residual fuel oil price. The effect of the ceiling is to limit the economic penalty incurred by industrial gas users who choose not to convert their existing facilities to coal.

The competitive position of natural gas has changed several times in the last decade. Industrial gas was delivered to users at near parity with residual fuel oil in the stable pre 1970s period. It was thus priced well below distillate. The first pipeline curtailments began in 1971. In late 1973 and early 1974, OPEC initiated the dramatic increases in international oil prices, thereby creating a significant competitive price advantage for natural gas. Between 1974 and 1978, however, oil prices declined in real terms while industrial gas prices continued a steady rise. In an effort to protect residential consumers from higher gas costs, utilities and regulatory commissions passed on a disproportionate share of the higher gas costs to industrial customers (as was shown in Table IV-2). By 1978, the price of industrial gas and residual fuel oil again approached parity.

The NGPA has institutionalized this practice of rate tilts for industrial boiler fuel customers. In fact, the industrial boiler fuel customer shifts from paying the lowest price for natural gas to paying prices occasionally above even the residential consumer. The disproportionate share of gas costs paid by industrial firms subject to incremental pricing effectively subsidizes other gas users. This subsidy is in addition to the subsidy inherent in the maintenance of wellhead price controls until 1985. As a consequence, natural gas regains the price advantage that prevailed from 1974 to 1978, particularly for the non-boiler fuel users of gas exempt from incremental pricing.

This competitive price advantage creates a substantial increase in demand for natural gas through 1984. In 1979 and 1980, the principal growth in gas demand was in the power generation sector for two reasons. Being exempt from incremental pricing, electric utilities found it quite attractive to substitute natural gas for oil. Secondly, the sluggish market for industrial gas (due to the slowly emerging recession) freed up volumes that could easily be absorbed into the electric utility market. For the balance of the period, the principal growth sector is expected to be industrial process gas users, particularly in the West South Central region (Texas, Louisiana, Oklahoma and Arkansas). With the NGPA-imposed price controls on intrastate gas (which previously had been unregulated), natural gas again becomes a very attractive fuel in the producing states.

Whether or not this demand actually materializes will depend on a number of non-price influences. Industrial users may be reluctant to attach new plants to natural gas systems without strong assurances of supply that may not be forthcoming. Secondly, following the substantial wellhead price increases expected to occur with deregulation in 1985, some industrial customers may choose to forego the price benefits in the short term. In any event, the rapid increase in deregulated gas prices in 1985 will have several effects. The subsidy effects of wellhead price controls will be largely eliminated, causing the industrial gas markets in the producing states to deteriorate. Secondly, the industrial gas customers that are exempt from incremental pricing will find their "subsidy" substantially diminished, thereby reducing the interstate industrial gas demand.

The Federal efforts to expand industrial utilization of coal have been largely resisted, not only because of the enormous capital costs of the conversion from gas or oil, but also because of local and Federal air quality standards. It is frequently suggested that an easing of the Clean Air Act would result in expanded use of coal at the expense of other fuels. A relaxation of environmental regulations would not affect our estimated gas demands from new boilers since we have already assumed a strict interpretation of the Fuel Use Act restrictions precluding gas consumption in new MFBI's. In existing facilities, a moderation of Federal environmental policy would be expected to increase industrial coal consumption. However, such a policy shift would not have a substantial impact on our industrial gas forecast.

There are two major causes for this apparent insensitivity to policy changes. The barriers to increased coal usage go beyond environmental regulations. Since converting existing gas and oil fired facilities to burn coal is largely technically infeasible, expanded coal use typically requires replacement of current equipment--an expensive proposition made more difficult by high capital costs, the competition for internal corporate funds and such mundane problems as inadequate land in many old industrial sites. In addition, because of the higher gas prices subsequent to deregulation, a large share of the industrial boiler market is already forecast to shift to alternate fuels. Since the boiler market is where additional coal use is expected to have its greatest impact--and our

projections already reflect significantly diminished use of gas under boilers--our industrial gas demand forecasts are not particularly sensitive to changes in environmental regulations. Coal consumption does expand, but at the expense of non-gaseous fuels.

Our industrial forecast is summarized in Table IV-6. Total stationary industrial energy demand is expected to increase three percent per year to 1990, with most of the increase occurring by 1985. Industrial conservation will continue to temper industrial demand, particularly after 1985 with its large increases in industrial energy costs. Industrial demand for natural gas will peak in 1985 and then decline as the most price-sensitive markets switch to other fuels. As a consequence, industrial gas markets in 1990 will not be substantially different than those that existed in 1979.

Gas Demand in the Electric Utility Sector

The demand for gas for the generation of electricity in the 1980s will be characterized by the following general conditions:

- overall, use of gas as a fuel in electricity generation will generally decline vis-a-vis other fuels;
- the greatest potential demand for gas in electricity generation will occur in the near term, with total potential demand generally declining annually through 1990;
- the demand for gas by electric utilities will, however, be constrained by the volumes of gas available for large boiler fuel uses--hence, unsatisfied gas demand will exist among electric utilities prior to deregulation;
- unsatisfied gas demand in the electric utility sector will be met primarily by oil, since generating facilities based on other fuels such as coal, uranium, and hydropower will already be operating at or near their functional upper limits.

In the 1970s, many electric utilities accustomed to using gas for power generation were forced by the onset of gas curtailments to turn to alternative generating fuels. In 1970, gas demand by electric utilities was 3.9 tcf and by 1977 had dropped to 3.2 tcf. With the return of gas availability to the large boiler fuel market, gas consumption for electricity generation had increased and in 1979, electric utilities consumed 3.3 tcf of gas. For 1980, we expect that gas demand from electric utilities (unconstrained by supply) will have risen even more--to approximately 3.7 tcf--and then begin declining over the rest of the decade.

TABLE IV-6

INDUSTRIAL NATURAL GAS DEMAND
1979 - 1990
(Trillion Btu)

	Actual 1979	Forecast		
		1984	1987 ^a	1990
Demand	6,973	9,410	7,166	6,949
Expected Deliveries	6,973	7,068	7,166	6,949 ^b
Deliveries as a Percent of Demand	100%	75%	100%	100%

^a The 1987 and 1990 demand forecast is based on a cleared market for natural gas.

^b Includes Alaskan volumes.

Source: Jensen Associates, Inc.
Gas Requirements Agency

The reason for the longer-term decline in the role of gas as an electricity generating fuel is that gas (and oil) is increasingly being relegated to a peakload generating status from its previous role as a baseload generating fuel. In effect, generating facilities designed to burn gas and/or oil are being used less than facilities based on other fuels--namely coal and uranium. Thus, the share that gas and oil together hold of the generating fuels market is declining. However, within this joint gas/oil share of the generating fuels market, gas has recently been gaining share vis-a-vis oil. In 1977, gas and oil accounted for 31 percent of the 2,115 billion kilowatt hours generated in the Lower 48 States. In 1979, this share dropped to 28 percent. Looking only at gas versus oil generation, gas accounted in 1977 for 46 percent of the 655 billion kilowatt hours generated by oil and gas together. By 1979, gas and oil were together utilized to generate only 624 billion kilowatt hours of electricity, but gas accounted for 53 percent and oil the remainder--a reversal of their position in 1977.

Over the 1980-1990 forecast period, we expect that oil will continue to be regarded as a fuel of last resort in the power generation sector. Similarly, gas will tend to share this characteristic, but the effects of rolled-in pricing on the gas side along with the existence of some low-priced, fixed gas contracts between some electric utilities and their gas suppliers, will make gas considerably more attractive than oil in those locales where it is available for power generation markets.

V. SUPPLY/DEMAND BALANCE

The increase in natural gas demand between now and 1985, prompted by the competitive price advantage of natural gas prior to deregulation, is not matched by an improvement in natural gas availability. As a consequence, a not inconsiderable gas shortfall is expected to develop, as shown in Table V-1. Since this shortfall is not due to a sudden decline in supply--as occurred in the interstate markets in the early 1970s with the advent of curtailments--but rather is due to a surge in demand, the gas industry can effectively manage the shortfall by carefully planning new load additions.

This excess demand collapses following the deregulation of wellhead prices when prices are free to rise to market clearing levels. In the post deregulation period, gas may be priced above the value of other fuels in some regions of the U.S., causing large users to switch away from gas and thereby reducing overall demand for gas. During the 1980-1984 period, there will be buyers who are willing to pay the regulated prices for gas, but cannot obtain it because supply is unable to keep up with demand.

The magnitude of the post January 1, 1985 adjustment in gas prices is dependent on the price of alternate fuels that will determine a market clearing price for gas. Based on our lower-bound oil scenario, the roll-in capacity (resulting from continued price controls on selected gas categories) in 1986 is estimated at approximately \$13 billion. Supplemental gas premiums above the market clearing price absorb \$2 billion and the balance represents the potential for flyup.

One of the key elements in establishing the level of flyup will be the price of residual oil because natural gas competes with residual oil in important marginal markets. High-priority markets typically develop rather slowly. Large increments of new supply can generally be quickly absorbed only in boiler fuel markets, and Alaskan gas is no exception. Thus, the initial deliveries of Alaskan gas are principally in low-priority uses--either directly or by displacement--where their major impact is to displace foreign oil. Gradually, the availability of the Alaskan natural gas allows high-valued process markets to expand their utilization of gas.

Since we expect petroleum product price spreads to be wider in the future, it would appear that refiners would have incentives to expand their yields of light products. Typically, such refinery upgrading would lead to reduced supplies of residual oil with attendant strengthening of residual oil prices--a scenario that would improve the market for natural gas. However, our analyses suggests that a substantial level of refinery investment will be necessary to keep residual oil yields no higher than they are presently due to the deteriorating crude slate available to U.S. refiners. Because of a petroleum product slate biased toward light products such as

TABLE V-1

SUPPLY AND DEMAND FOR U.S. NATURAL GAS
1980 - 1990
(Trillion cubic feet)

<u>Potential Gas Demand</u>	<u>Estimated 1980</u>	<u>Forecast</u>		
		<u>1984</u>	<u>1987</u>	<u>1990</u>
Residential	4.8	4.9	4.9	4.8
Commercial	2.6	2.6	2.6	2.6
Industrial	6.8	9.2	7.0	6.8
Power Generation	3.7	3.4	2.4	2.2
Other	<u>2.6</u>	<u>2.3</u>	<u>2.1</u>	<u>2.0</u>
Total Potential Demand	20.5	22.4	19.0	18.4
<u>Expected Gas Supply</u>				
Total Supply (Excluding Alaska)	20.5	19.2	18.3	17.7
<u>Shortfall</u>				
Without Alaska	--	3.2	0.7	0.7
With Alaska	--	3.2	0	0

Source: Jensen Associates, Inc.
Gas Requirements Agency

gasoline, U.S. refiners generally prefer the light African crudes from Nigeria, Algeria or Libya--crudes that are not substantially different from domestic crudes.

These light crudes typically have very low residual fuel oil yields. However, world reserves of crude oil are increasingly biased toward heavy crudes that yield significantly higher outputs of residual oil. If residual fuel oil supplies remain high relative to the market, it tempers the degree of flyup. The essentially by-product residual oil produced will be priced as low as necessary to dispose of it, thereby softening natural gas prices. The 1979-1980 collapse of the residual fuel oil market in the Midwest is a good example. Excess supply of residual oil caused the price to drop substantially at a time when crude oil prices were rising. As a consequence, natural gas prices in some industrial markets relaxed in order to maintain market share in the face of a shrinking overall demand for energy due to the economic downturn that affected the Midwest so strongly. Such events are likely to occur again subsequent to 1985. Although our forecast suggests an essentially balanced market, sporadic market disorder (created by abrupt changes in economic activity, large increases in supply, etc.) may occasionally cause spot surpluses and shortages.

Comparison of our supply and demand forecasts indicates a gas surplus during all of 1980 and 1981, reaching a balance during 1982 and shortfalls in 1983 and 1984. Then, following market adjustments to large gas price increases which occur in 1985, we find a continuing balance of supply and demand through 1990. Figure V-1 summarizes these changes in gas market balances for the years 1980, 1984, 1987 and 1990. This graph shows that in 1980, a total gas supply surplus of about one-half tcf existed and that this situation is expected to change to a shortfall of over 3 tcf by 1984. Following the 1985 gas price increases from decontrol, supply and demand will be essentially in balance.

The Impact of Early Deregulation

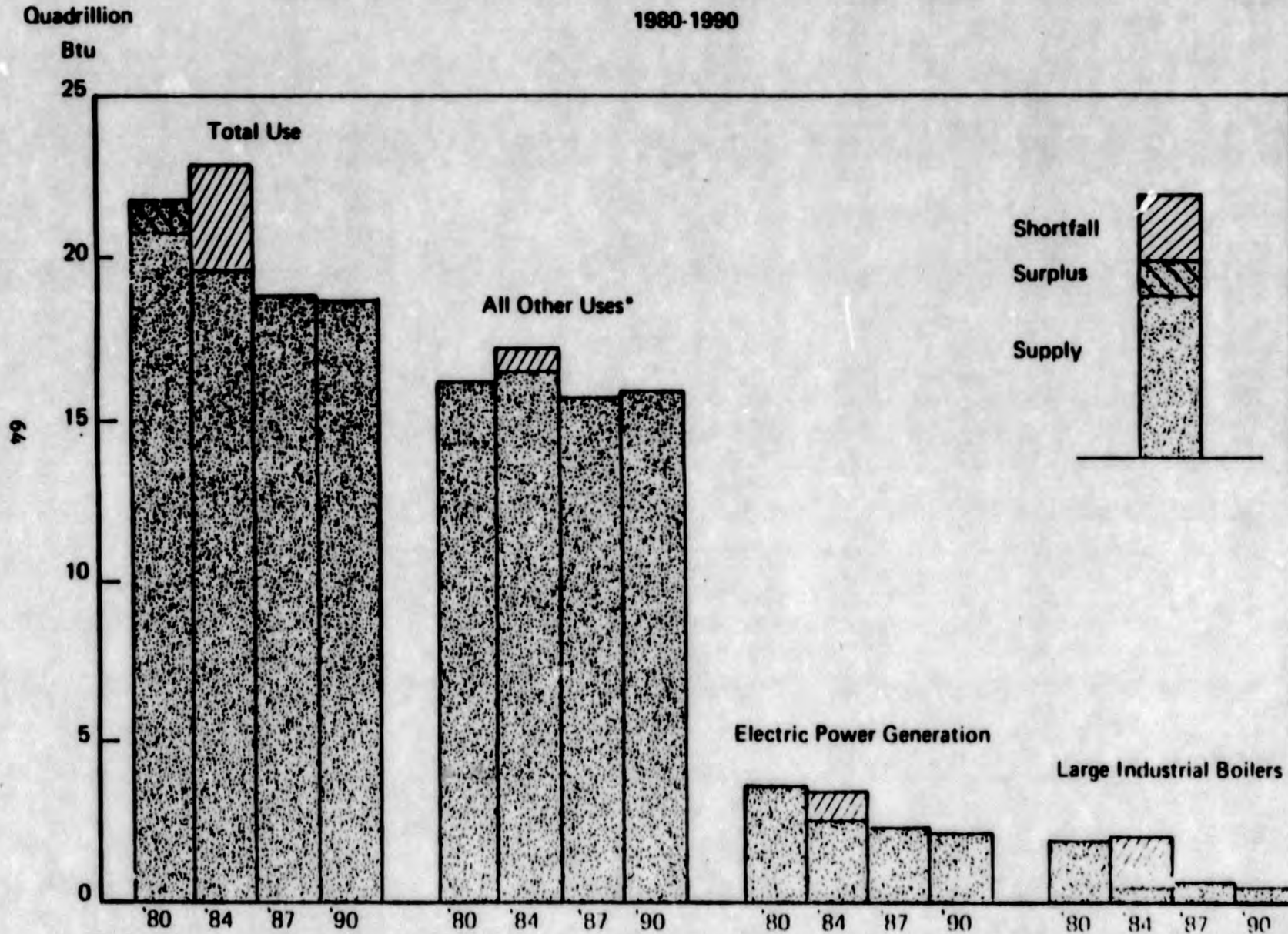
The election of Ronald Reagan, together with a Republican Senate in November 1980, has signalled a conservative shift in American politics. Reagan's economic advisers strongly support private sector investment and economic activity under the stimulus of market forces. In oil and gas, the emphasis on supply-side economics quickly translates into deregulation. Deregulation of crude oil was quickly accomplished in January 1981 by Presidential order; an accelerated timetable for new natural gas deregulation or full deregulation would require Congressional action, but may well be proposed by the Administration. The analysis in this report is largely based on an assumption of the continuation of the Natural Gas Policy Act of 1978, which provides for new gas deregulation in 1985. The major question which naturally follows is, "What would be the effect on markets for Alaskan natural gas?"

We have not examined early deregulation in detail and therefore can only speculate about its possible effects on Alaskan gas markets. We do

FIGURE V-1

GAS SUPPLY/DEMAND BALANCES BY USER TYPES

1980-1990



*Includes residential, commercial, industrial (except large boilers) and other.

Source: Jensen Associates, Inc.

not share the view that immediate gas price deregulation would so stimulate the supply side that it would obviate the need for supplementary sources such as Alaska. We are persuaded that the impact of early deregulation would be much greater on market ordering and on demand than it would be on supply.

Higher oil and gas prices and the prospects for scheduled deregulation have already provided a powerful incentive for drilling activity. Both oil and gas well completion footage have increased by more than 40 percent in the past three years, gas footage nearly quadrupling and oil footage nearly doubling over the decade. The limitations imposed by leasing rates, geophysical crews, drilling rigs, and most importantly, evolving ideas for new drilling prospects serve to restrict the rate at which acceleration of the drilling incentive can produce concrete discovery results. Experience suggests that as drilling activity rises too rapidly, the yield--mcf discovered per foot drilled--may fall to offset the activity increase. Thus, although we would expect to see some supply improvement from immediate deregulation, we would not expect it to be large.

On the other hand, our projection of excess demand for gas is largely dependent on maintaining the disparity between price-controlled gas and international oil prices. Clearly, deregulation would permit gas, oil and coal markets to balance themselves more evenly over the 1981-1985 period, providing a more orderly market in the process. This would, presumably, eliminate much of the excess gas demand. The greatest concern about early new or full gas deregulation is its potential effect on roll-in capacity and the ability to subsidize the early entry of Alaskan gas into Lower 48 markets. In our lower-bound oil price forecast case, Alaskan gas is priced above market clearing levels in the early years and requires roll-in to enable it to compete in the marketplace. An acceleration of new gas deregulation would not significantly alter the relationship between clearing prices and the average price of old regulated gas, and thus--in our view--would not substantially change the extent of roll-in. It would clearly have an effect on the way in which flyup occurs.

Full deregulation, however, would permit all gas to rise to contractually-determined--as distinct from regulatory-determined--price levels. To the extent that indefinite pricing provisions exist in old gas contracts--and much of the old gas in 1987 will be produced from reserves discovered since 1973 where such clauses are common--prices could rise to eliminate a substantial portion of roll-in capacity. There is no guarantee that roll-in capacity would disappear entirely since many contracts have pricing provisions which would prevent their tracking deregulated prices directly. But to the extent that the roll-in capacity which would otherwise serve to cross-subsidize the Alaskan gas is substantially diminished by full deregulation, other means of accommodating the Alaskan price might be utilized. These could include such things as variations in rate design, greater use of market risk clauses or netback pricing approaches. Netback pricing, which is common in a deregulated market economy, sets the delivered price equal to the market clearing level and permits the wellhead

price to vary as necessary within the terms of the contract. For crude prices higher than the lower-bound case--such as, for example, our least unlikely case--the issue disappears since Alaskan gas quickly becomes competitive in its own right without the need for roll-in.

THE MARKETABILITY OF ALASKAN NATURAL GAS

A Summary for Congressional Hearings
by Jensen Associates, Inc.

In our studies of the marketability of Alaskan natural gas, we at Jensen Associates, Inc. have concluded that commercial markets will exist for gas from this project throughout the project's lifetime. Despite an acceleration of drilling activity, the long-term prospect is for a decline in natural gas production from traditional Lower 48 sources. As a result, supplements--such as Alaskan gas from this project, imports, and unconventional sources--will be required if the gas industry is to avoid a substantial loss in its traditional contribution to U.S. energy supply. Efforts to diversify energy sources in the U.S. away from oil are continuing, but we believe that on the margin imported oil will remain the chief competitor for natural gas well into the 1990s. We believe that world crude oil prices will inevitably rise in real terms over the course of the project, although the timing and extent of individual price increases will almost inevitably be erratic. For the next year or so prices, indeed, are more likely to fall than to rise. There is thus a likelihood that the initial price of Alaskan gas will be above the price at which gas markets will clear against oil, requiring some price accommodation for Alaskan gas to assure that it can compete. Congress provided just such a transitional pricing approach in allowing roll-in treatment for Alaskan gas under the Natural Gas Policy Act of 1978.

But if for some reason roll-in is not available, changes in the "front end loading" pricing pattern for Alaskan gas, such as netback pricing at the wellhead and levelized rate design, provide similar price accommodation. We thus believe that a market does exist, and that some mechanism can be utilized to assure that prices can be competitive in the early years.

The year 1981 has proved to be a year of extraordinary upheaval in U.S. and world energy markets. The natural gas shortage which plagued the U.S. in the early and mid-1970s has given way to a "gas bubble" which has persisted for so long that many now call it simply a "gas glut." World petroleum markets are in even greater turmoil; the oil price increases which were set in motion by the Iranian revolution in late 1978 have had a major impact on world oil demand. Only a few years ago, many wondered whether OPEC would be willing or able to produce an expected requirement of more than 40 million barrels per day by the mid-1980s. Two years ago, at this time, demand for OPEC oil exceeded 31 million barrels per day and was threatening OPEC's allowable production capacity; at the moment, net demand for OPEC production has dropped to 20 million barrels per day. World oil prices, which rose more than two and one half times in the chaotic markets of 1978 to 1980, are now falling--not only in real terms, but in current dollar prices, as well--as OPEC price hawks are forced to discount to retain some semblance of an oil market share. The changes have been sudden. Even the formal report submitted with this testimony, and which is dated only three months ago, foresaw a drop in OPEC demand this year to 23 million barrels per day from the then statistical base of 25

million barrels per day; it is now 3 million barrels per day lower than that. In this kind of market, it is tempting to conclude that there is enough natural gas, enough oil, and that the energy problem is almost a thing of the past.

The gas from Alaska, however, is not expected to flow until the winter of 1986/1987, so that the markets which concern us are not those of October 1981, but those of 1987 and the years following. A simple observation can illustrate the rapidity with which energy markets can change and place marketability issues in a new context. South Louisiana is a major contributor to today's gas bubble because of the prolific production rates possible with its reserves. If one were to make the simplifying assumptions that depletion rates in the area could be maintained at current levels and that no new discoveries would be made, the gas from South Louisiana would be virtually all gone by the time the Alaskan gas comes on line. South Louisiana is the largest gas producing area in the U.S., representing 26 percent of Lower 48 reserves and 35 percent of Lower 48 production. We do not mean to suggest that these assumptions are realistic, but only to show how greatly energy markets will have changed by that time.

Our evaluation places the marketability question in three broad contexts--the outlook for natural gas demand, the outlook for supply, and the role of price. Estimates of future natural gas requirements have been steadily reduced as observers have become aware of the extent to which natural gas demand is responsive to price. But although target requirements are down, we believe the long-term outlook for Lower 48 production

is also down despite current optimistic trends in gas well drilling activity. Thus supplements will increasingly be needed to satisfy the projected requirements.

The underlying driving force which will be most influential in creating increased demand for gas in general, and a market for Alaskan supplies in particular, is an increase in real prices for world oil. A major portion of existing U.S. industrial and power generation plant capacity is designed for oil and/or gas firing and is not readily convertible to coal or other fuels. Thus, rising oil prices quickly shift demand to gas. In addition, prices of most supplementary gas supplies--such as Canadian, Mexican or LNG--are being linked to oil. Rising real prices for oil thus make Alaskan gas--without such linkage--increasingly attractive relative to alternate supplies.

The Outlook For Natural Gas Demand

If the NGPA were to go to term in its present form, we foresee two distinct periods of gas demand behavior during the 1980s. Prior to new gas price decontrol in 1985, gas demand will grow in the price-sensitive industrial and power generation sectors as the price gap between gas and fuel oils remains. By 1983 this increasing demand will have absorbed the current gas supply surplus and exceeded available supply, creating an imbalance period lasting until decontrol of new gas prices in 1985. Following decontrol, gas prices will rise rapidly relative to other fuels causing some loss of demand by industrial and electric utility users. Price will then bring supply and demand into balance for the rest of the decade and beyond.

During the entire decade, residential and commercial demands will remain essentially constant. Industrial and power generation demands will increase significantly through 1984. Following gas price decontrol, the latter two price-sensitive demands will drop sharply as they switch to cheaper fuels.

Our demand estimates are shown in Table I. If the deregulation provisions of NGPA are modified by Congress through some form of accelerated deregulation, the impact on the market would be to clear it earlier, eliminating the excess demand we foresee prior to 1985. The volume effects would tend to be concentrated in those same markets which would not be served under conditions of excess demand--industrial boiler requirements and dual-fueled power generation demand.

The Outlook For Gas Supply

Natural gas reserve additions in the Lower 48 States last exceeded production in 1967 and, as a result, proved reserve levels in the U.S. have steadily declined. The industry has been able to effect a partial offset to this sharp decline in proved reserves by steady increases in the rate-of-take from remaining reserves. This has occurred both as a result of increased emphasis on in-fill and other relatively low-risk development drilling activity, as well as from the fact that the major Gulf Coast producing region is geologically capable of quite rapid depletion rates.

We do not believe that the increased drilling rates which we foresee will be sufficient to offset the steady decline in gas reserves added per foot of drilling effort. Therefore, we expect a continued decline in Lower 48 proved reserves. In addition, because of the changes in regional

Table I

LOWER 48 STATE GAS DEMAND FORECAST SUMMARY

(Quadrillion Btu)

<u>Sector</u>	<u>Estimated Consumption 1980</u>	<u>Forecast Demand</u>		
		<u>1984</u>	<u>1987</u>	<u>1990</u>
Residential & Commercial	7.5	7.7	7.7	7.6
Industrial	7.1	9.4	7.2	6.9
Power Generation	3.6	3.5	2.5	2.2
Other	<u>2.8</u>	<u>2.3</u>	<u>2.1</u>	<u>2.0</u>
Total Demand	<u>21.0</u>	<u>22.9</u>	<u>19.5</u>	<u>18.7</u>

Source: Jensen Associates, Inc.
Gas Requirements Agency

patterns of discoveries and in the nature of drilling activity, we foresee that at some point, production rates as a percent of proved reserves will peak, causing production to fall more rapidly thereafter. Thus, supplementary sources of gas supply will increasingly be needed to compensate for declining Lower 48 production. We do not share the view that early price deregulation would so stimulate the supply side that it would obviate the need for supplementary sources such as Alaska. We believe the effects of early deregulation would be much greater on market ordering and on demand than it would be on supply.

Our forecast of Lower 48 State conventional production declines by 28 percent between 1980 and 1990. This is partially offset by an increase in supplemental supplies such as pipeline imports from Canada and Mexico, LNG imports, synthetics, Alaskan gas and unconventional production. The result is that total supply declines 11 percent during the decade, from 21.0 quads in 1980 to about 18.7 quads in 1990. Details of our supply forecasts are provided in Table II. Our gas supply/demand balance--under the assumption of continuation of NGPA as it stands--are shown in Figure I.

The Role of Price

Perhaps the single most important element in competitive fuel price formation during the 1980s will be the outlook for international oil prices. Rising real prices for OPEC oil supplies have two important effects on oil and gas competition. First, rising oil prices tend to stimulate the demand for gas at the expense of oil--particularly in the price-sensitive dual-fuel market. But since prices of most supplementary

Table II

LOWER 48 STATES GAS SUPPLY FORECAST SUMMARY

(Quadrillion Btu)

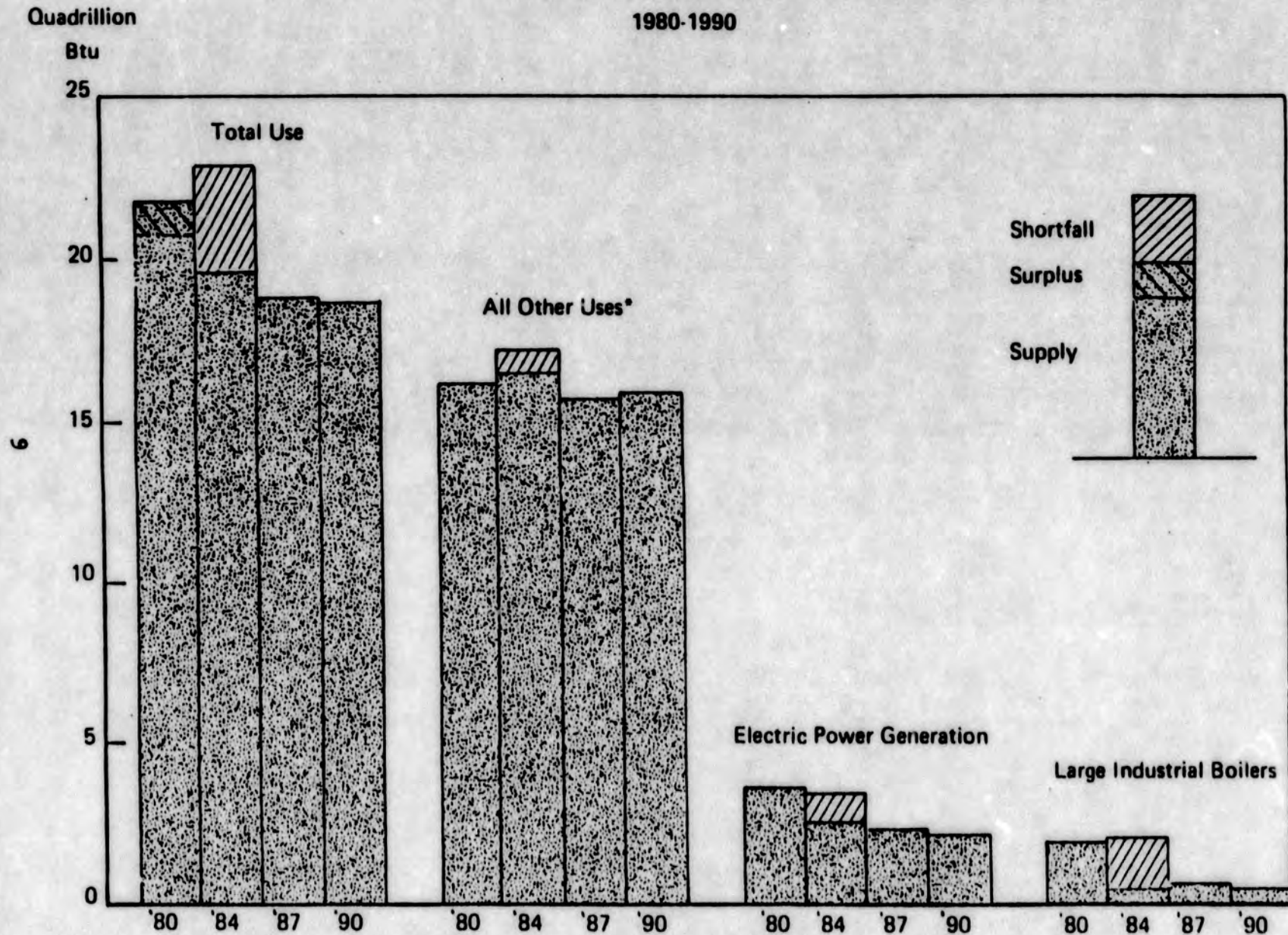
<u>Source</u>	<u>Estimated 1980</u>	<u>Forecast</u>		
		<u>1984</u>	<u>1987</u>	<u>1990</u>
Conventional Production	19.9	16.8	15.5	14.4
Unconventional Production	--	0.1	0.1	0.3
Imports	1.0	2.6	2.9	2.9
Alaskan North Slope	0	0	0.8	0.8
Synthetics	<u>0.1</u>	<u>0.1</u>	<u>0.2</u>	<u>0.3</u>
Total Supply	<u>21.0</u>	<u>19.6</u>	<u>19.5</u>	<u>18.7</u>

Source: Jensen Associates, Inc.
Department of Energy

Figure 1

GAS SUPPLY/DEMAND BALANCES BY USER TYPES

1980-1990



*Includes residential, commercial, industrial (except large boilers) and other.

Source: Jensen Associates, Inc.

supplies, such as LNG or overland imports, will increasingly be tied to international oil price levels, rising oil prices make these sources relatively less attractive by comparison with Alaskan gas. Thus, a rising oil price environment makes Alaskan gas increasingly competitive, not only with oil, but with most other supplementary gas sources as well.

The year 1981 has seen a marked shift in the outlook for world oil supplies and prices. The successful weathering by world oil markets of the Iraq-Iran crisis, together with unexpectedly high reductions in world oil--and OPEC oil--demand has forced most oil economists to moderate their projections. In our formal report we utilize a "lower bound" oil price projection to test the marketability of Alaskan gas. We believed at the time the report was written--and believe now--that the "lower bound" price projection is a conservative statement of oil price behavior over the decade. But with the events in world markets of the summer and fall of 1981, it is probably no longer appropriate to describe it as a "lower bound" case in the early years before Alaskan gas flows, since the turnaround in world oil demand may be extended beyond 1983. Our forecasts of long-term crude prices continue to reflect the expectation that price behavior during crisis will be a major element of future oil price formation.

From 1973 to 1981, prices of international oil to U.S. markets rose at an average rate of nearly 14 percent per year in real terms. This was not a classical steady growth curve, however, since virtually all of the increase was confined to two comparatively short periods--October 1973 to February 1974 during the Arab oil embargo, and again from December 1978 to

February 1980 precipitated by the Iranian revolution. There is thus compelling evidence that the dominant force in real price increases over the decade has been the panic buying which accompanied the crisis markets of 1973/1974 and 1978/1980 rather than any orderly price administration by OPEC. OPEC's principal role has been to resist the erosion of real oil prices during the periods between rises. A forecaster who ignored the crisis element would have been right nearly seventy percent of the time, but might have missed the action of markets during which nearly eighty percent of the price increase occurred. The crisis element in price formation arises when political disruption coincides with a high level of net demand on OPEC. The coincidence was there in 1973 and again in late 1978. Prices weathered one tight market in late 1976 without taking off since the element of political disruption was missing. Conversely, the onset of the Iraq-Iran war occurred while markets were softening and the assassination of Anwar Sadat occurred at the lowest level of net demand for OPEC oil in the last thirteen years.

The magnitude of the present drop in OPEC demand, and the anticipated return of Iraq and Iran to the market, have convinced many observers that tests of OPEC's willingness or ability to produce are a thing of the past. But current production levels are misleading in a world in which OPEC tends to absorb much of the energy downswing, and a combination of worldwide economic downturn and contraseasonal inventory liquidation has pushed OPEC demand to abnormally low levels. For example, current estimates of worldwide inventory liquidation range as high as two million barrels per day during a season when inventories are normally expected to

increase by two million barrels per day--a four million barrel per day swing. In our view, net demand on OPEC oil will increase again after the completion of the current inventory liquidation, and a resumption in growth of economic activity in the OECD, perhaps during 1983. With the limited prospects for any significant increase in OPEC's available capacity over the decade, we believe that capacity--and price--will be tested again even without a new major disruption in the Middle East.

In our formal report, we have utilized two forecasts of oil prices. One of these--our least unlikely case--was based on the expectation that international oil price formation would operate very much during the 1980s as it has during the 1970s. The dominant feature of recent international oil price development has been a sporadic political or military crisis in the Middle East; this has generated panic buying in the marketplace and a rapid escalation in oil prices. These prices subsequently decline in real terms as the disruption passes and world economic activity reacts to the sharp dislocations in pricing. For our least unlikely case, we arbitrarily assumed that a disruption would occur in 1984 and the pricing pattern both during and after the disruption would be similar to 1973/1974 and 1979/1980.

For purposes of our market analysis, however, we have assumed that such a forecast, with its disruptive price pattern, would not present a credible test of the marketability of Alaskan gas. Therefore, we have utilized instead a "lower-bound" price case which assumes declining real prices through the end of 1982 with a turnaround thereafter. From the low point starting in 1983, we anticipate a three percent per year

increase, the rate at which we believe the OPEC long-term strategy pricing formula would operate if it is adopted by the end of 1982. The net effect of this price forecast is a real price increase of 1.8 percent per year from 1980 to 1987.

It is this projection which we have utilized in this report to test Alaskan gas marketability. The basic crude projection has been adjusted for transportation and other crude oil sources, and then converted into a price series for the refiners' acquisition cost of crude oil. This series has been used in turn to develop both distillate and residual fuel oil prices by region.

In the Natural Gas Policy Act, Congress granted Alaskan gas the right to rolled-in treatment for ratemaking purposes. This was designed to permit price-controlled old gas (which will continue long after 1985 new gas deregulation) to cross-subsidize any portion of the price of Alaskan gas over and above market clearing price levels. In a high oil price scenario, Alaskan gas quickly becomes competitive on the margin, as real oil prices overtake the initially higher-priced Alaskan gas. In our least unlikely combination of oil and gas prices, Alaskan gas requires little roll-in treatment during the early years to be marketable.

However, in our lower bound case, Alaskan gas must rely--in the early years, at least--on some form of price accommodation such as the rolled-in treatment which Congress granted it in the NGPA. We estimate that if the NGPA goes to term, the 1987 market will have 25 percent of total U.S. gas supply still regulated below the market clearing levels, amounting to a roll-in capacity of \$11.7 billion. Other supplementary gas supplies,

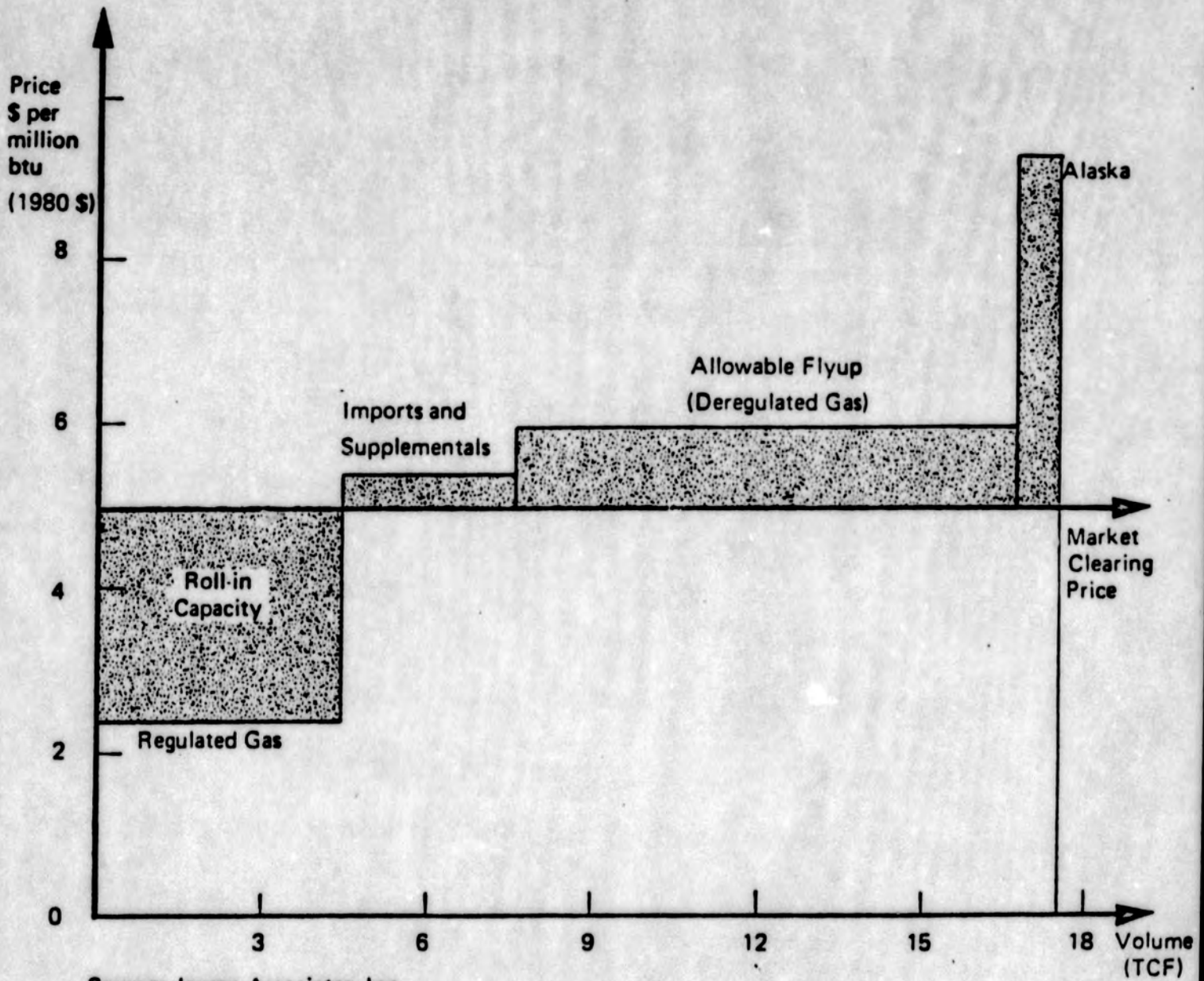
priced above clearing levels, will utilize a portion of this capacity, but most of it remains to accommodate the Alaskan gas and to provide a potential for "flyup"--the rapid market and contractual escalation of deregulated new gas prices in 1985. Figure II illustrates the roll-in capacity numbers for 1987 when the relative prices of Alaskan gas and oil are least favorable.

The extent to which this roll-in capacity will actually be available depends on world oil price levels, the nature of gas price regulation between now and 1985, and the extent to which the gas pipeline industry, through its contracting practices, may lock in enough deregulated gas price escalation to absorb part of this capacity. We have assumed that the individual reselling pipelines would be in the best position to coordinate their gas contracting practices, their markets, and the rolled-in accommodation of Alaskan gas. Indeed, we have seen evidence of just this sort of integrated supply/market planning taking place, and as a result our report concludes that the roll-in capacity will be there for the lower bound case.

The recent debate over early gas deregulation, the turbulence in world oil markets and the response of OPEC, raise legitimate questions as to what would happen to the markets for Alaskan gas if the roll-in capacity is not available as Congress intended. It is important to recognize that the Alaskan price projections utilized throughout our report and illustrated in Figure II are "front-end loaded." The cost-of-service ratemaking approach utilized by U.S. utilities attempts to recover operating costs and a return on undepreciated plant investment in the rates

Figure II

1987 ROLL-IN CAPACITY OF U.S. NATURAL GAS MARKETS
(Based on Lower Bound Crude Price
and
Upper Bound Alaskan Price)



Source: Jensen Associates, Inc.

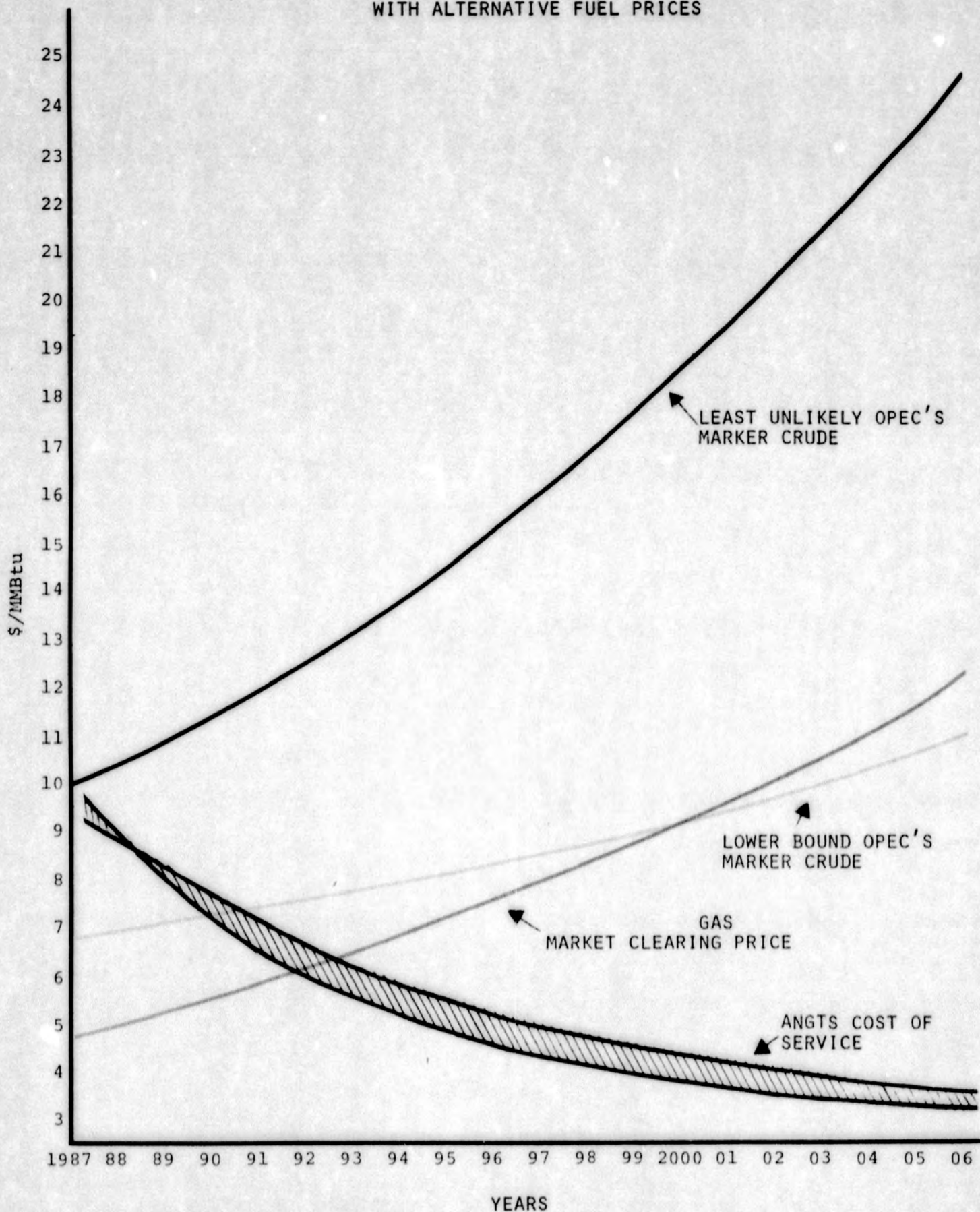
charged to customers. This makes rates, for a major project such as this one, highest at start-up and declining thereafter as the plant investment is depreciated. In addition, the Congressional preference for price regulation of Alaskan gas at the wellhead represents an abandonment of the more customary "netback" approach to new project wellhead pricing where producers charge no more than what the market will permit during early years, in return for greater pricing flexibility later on. This approach prices gas higher in the early years than it would be priced under the customary netback approach and is thus also front end loaded. By adopting approaches which have the effect of shifting to a more level rate structure over the life of the project, the sponsors have much more flexibility to accommodate those market uncertainties than the schedule of prices which we have utilized in this report might suggest. No one that we know is seriously suggesting that OPEC oil could continue to be cheaper than Alaskan gas over any significant period of project life.

In summary, we believe that a commercial market for Alaskan gas will exist in 1987. Its volumes will be required along with other supplements if natural gas is not to play a significantly reduced role in meeting future U.S. energy demands. In our least unlikely world oil price scenario, Alaskan gas will increasingly be competitive with alternate gas supplies, which will be largely linked to oil. Lower oil price scenarios, such as the lower bound estimate which we have utilized in our report, will require some price accommodation in the early years. Congress has provided for the use of roll-in capacity to help Alaskan gas through the early start-up years, but other pricing approaches such as wellhead net-

back pricing and changes in pipeline rate design can also be utilized to accommodate the market.

APPENDIX F

COMPARISON OF ANGTS COST OF SERVICE
WITH ALTERNATIVE FUEL PRICES



APPENDIX G

**Net National Economic Benefits
of the Alaska Natural Gas
Transportation System**

Prepared for:
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July 1981

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Introduction

The Alaska Natural Gas Transportation System (ANGTS) is the largest privately financed project ever to be considered. Its completion will generate enormous net national benefits. The present value of the Alaskan gas that ANGTS will bring to the United States is likely to be between \$90 and \$140 billion.* The total present cost of delivering this gas (including the wellhead cost of the gas) is approximately \$50 billion over the 25-year project life. Accordingly, the present value of the net benefits of ANGTS is between \$40 and \$90 billion for all U.S. parties associated with the project. For our base case, we use the median gas value of \$110 billion, which yields a median NNEB of \$60 billion. All of the above values are in January 1980 dollars, discounted in real terms at 3 percent to mid-1981.

The parties associated with ANGTS include the consumers, the state and federal governments, and the project investors. The benefits will provide the project investors with returns sufficient to attract their respective investments. Additionally, the governments will receive benefits in the form of tax receipts.

In September 1977, President Carter rendered a decision that the Northwest Alaskan Pipeline Company be designated to construct and operate those portions of the ANGTS within the State of Alaska.** Because project

* These values are the mode and expected value for the gas value, respectively.

** Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977). Hereinafter cited as the Decision. Northwest Alaskan Pipeline Company is the operating partner for the consortium (Alaskan Northwest Natural Gas Transportation Company) presently sponsoring the Alaskan segment of ANGTS.

cost estimates have changed substantially since the Decision, the project sponsors must demonstrate that the project is still in the public interest.*

Accordingly, Northwest Alaskan Pipeline Company asked Resource Planning Associates, Inc. (RPA), to independently assess the net national economic benefits (NNEB) of ANGTS. Northwest Alaskan Pipeline Company provided the project cost assumptions for the analysis. RPA conducted the analysis of the NNEB and we present our findings in this report. First, however, we define the NNEB and explain the report organization.

DEFINITION OF NET NATIONAL ECONOMIC BENEFITS

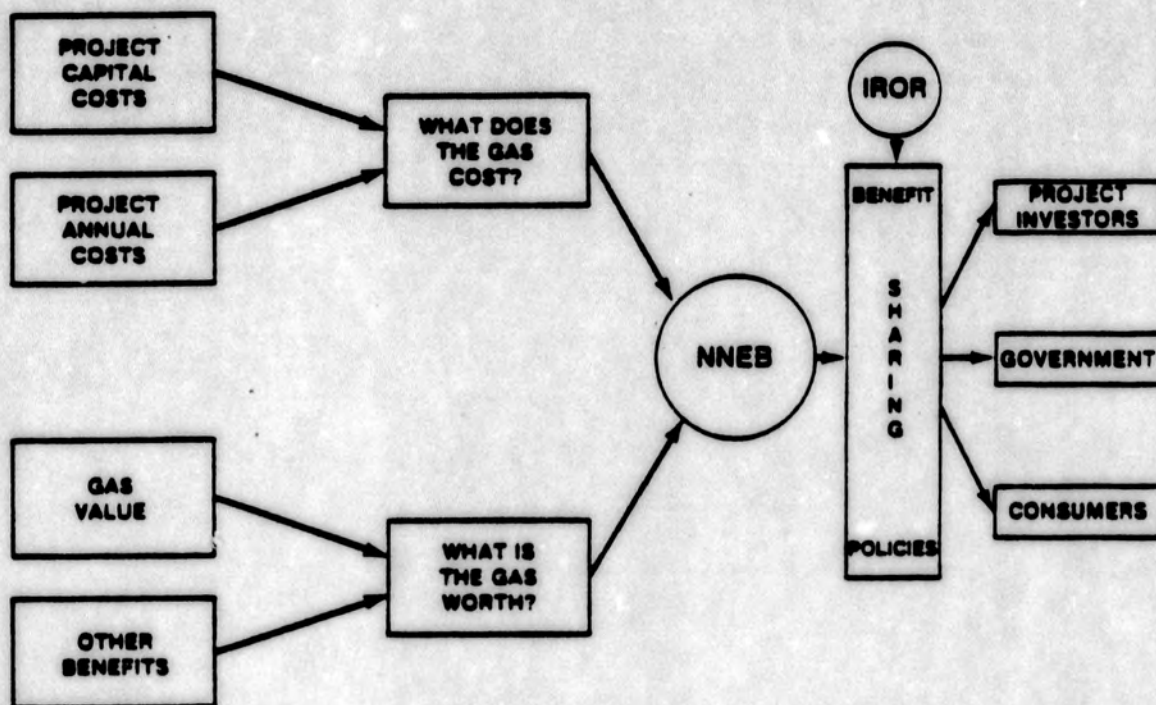
Net national economic benefits of a project are simply the economic costs subtracted from the economic benefits. As shown in Exhibit 1, the total costs of the delivered gas are the sum of two major cost categories: the project capital costs and the project annual costs. The latter consist mainly of the price of the gas at the wellhead. The gas is valued at the wellhead for the annual cost calculation. The benefits of the gas derive from the market value of the gas.**

* Order No. 31, "Order Setting Values for the Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," Docket No. RM78-12 (June 8, 1979), p. 53.

** Our evaluation excludes indirect benefits, such as increased energy independence, improved balance of payments, and more jobs. Consequently, our estimate of the value of the gas is conservative.

Exhibit 1

NNEB OVERVIEW



The time patterns for the costs and benefits of ANGTS are significantly different. The capital costs are incurred prior to gas flow, whereas the benefits accrue over a minimum 25-year project life. Therefore, the NNEB is largely a matter of society's time value of capital. In our analysis, we used a 3 percent real discount rate for the base case assumption. With an inflation rate assumption of 11 percent, the annual discount rate is 14 percent.

As shown in Exhibit 1, the NNEB is the total value available for sharing among project investors, government, participants, and consumers. The relative shares are determined by project costs, market factors, laws and regulations (such as the Federal Energy Regulatory Commission's incentive rate of return mechanism), and tax policies.

REPORT ORGANIZATION

This report is divided into three parts. In Chapter 1, we present the value of the gas to be delivered by ANGTS. We used an approach that combines the judgment of 28 nationally recognized energy experts to show that the value of the gas is large under all reasonable circumstances. Chapter 2 presents the capital and annual costs for the project, as provided by Northwest Alaskan Pipeline Company. Chapter 3 combines the results of Chapters 1 and 2; in it we elaborate on our definition of NNEB and examine the sensitivity of the base case to changes in several major assumptions. We also demonstrate that the NNEB is large under all reasonable circumstances.

The value of the delivered Alaskan gas is a major determinant of the NNEB. It is also the most difficult factor to predict, due to its heavy dependence on highly uncertain future energy prices. Consequently, we devoted a major effort in the NNEB analysis to this area. This effort involved utilizing the judgments of a broad cross-section of nationally recognized energy experts.

We define the value of delivered Alaskan gas as the wholesale revenue it could command at the pipeline termini -- that is, at the Chicago and San Francisco region gateways* -- in an unregulated environment. This is equivalent to the wholesale cost of fuels that would be consumed in the absence of Alaskan gas, approximately adjusted for differences in the costs of local distribution and end-use utilization. In Chapter 3, we explain the use of gas value, thus defined, in calculating the NNEB.

To account for the high degree of uncertainty in the future value of Alaskan gas, we interviewed 28 nationally recognized experts on future energy prices. These interviews were conducted during the first quarter of 1981. These experts and their affiliations are listed in Exhibit 1.a. The combined results of our interviews are summarized as a probability distribution in Exhibit 1.b. On a levelized basis, the median gas value is \$9.17 per million Btu in 1980 dollars. The expected value is \$11.79 and the mode (most likely) is \$7.50. The probability of a value less than \$4.94 is 10 percent, as is the probability of a value greater than \$18.32.

* A small amount of Alaskan gas is also delivered within the State of Alaska. This is included in our definition of the value of ANGTS gas.

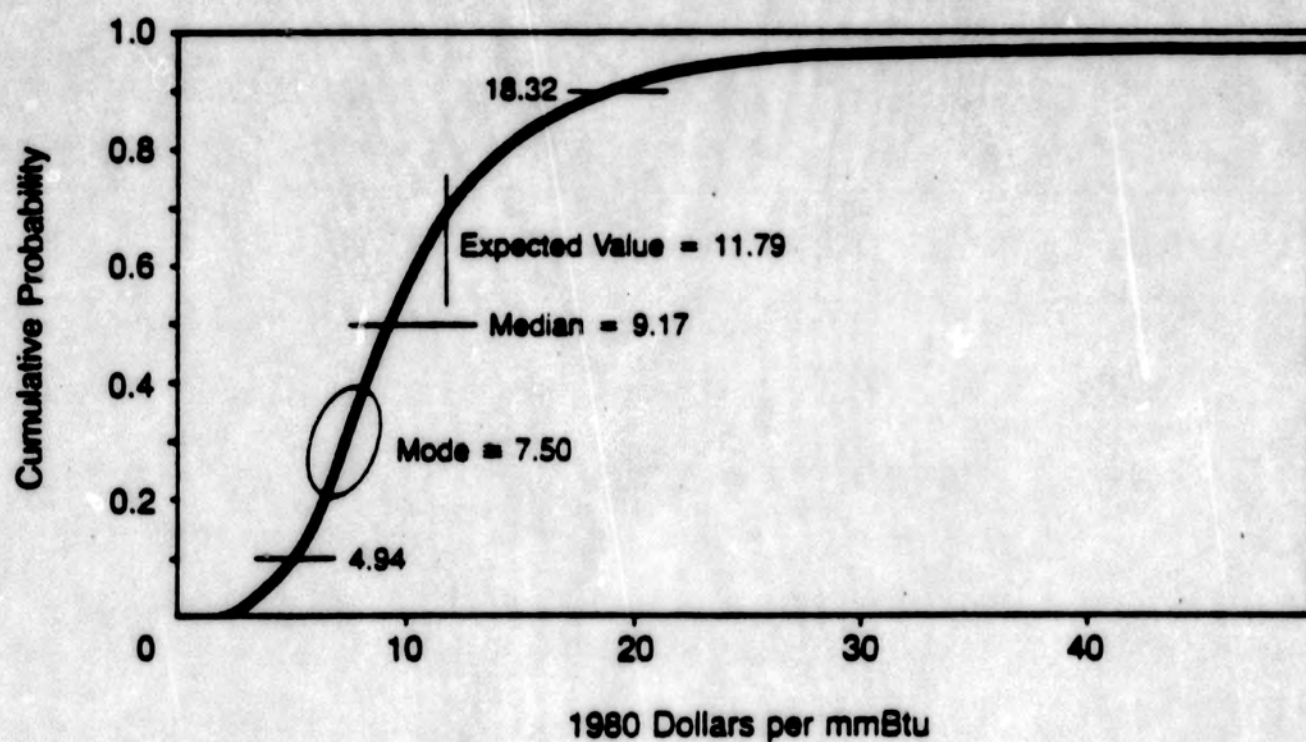
Exhibit 1.a

PARTICIPANTS IN ANALYSIS OF
THE VALUE OF ALASKAN GAS

Expert	Affiliation
Alvin Alm	Harvard University
Michael Barron	Department of Energy
Kenneth Darrow	Gas Research Institute
John Ecklund	Central Intelligence Agency
Robert Fri	Energy Transition Corporation
J. Michael Gallagher	Bechtel
Dermot Gately	New York University
John Gault	Jensen Associates
Roger Glassey	University of California, Berkeley
Eugene Harless	SRI International
Patrick Henry	Booz, Allen, and Hamilton, Inc.
Charles Hitch	University of California, Berkeley
Larry Jacobsen	Federal Reserve Board
Michael Kennedy	University of Texas
John Lichtblau	Petroleum Industry Research Foundation, Inc.
Henry Linden	Gas Research Institute
Rene Males	Electric Power Research Institute
Ted Moran	Georgetown University
Roger Naill	Department of Energy
Richard Nehring	Rand Corporation
Dale Nesbitt	Decision Focus, Inc.
David Nissen	Chase Manhattan Bank
Warner North	Decision Focus, Inc.
James Plummer	Electric Power Research Institute
James Reddington	Department of State
Benjamin Schlesinger	American Gas Association
John Stanley-Miller	Department of Energy
James Sweeney	Stanford University

Exhibit 1.b

COMPOSITE DISTRIBUTION ON THE ANNUITY
EQUIVALENT VALUE OF NATURAL GAS



For our base case, we assume the delivered volume of gas to be approximately 2 billion cubic feet per day, beginning in late 1986 and continuing for 25 years. This is the flow rate already authorized by the State of Alaska, and sufficient gas reserves have been proven to assure its feasibility.

Using the assumptions described above, the median present (mid-1981) value of the gas is \$110 billion in 1980 dollars. The mode and mean values of the gas are \$90 and \$140 billion, respectively.

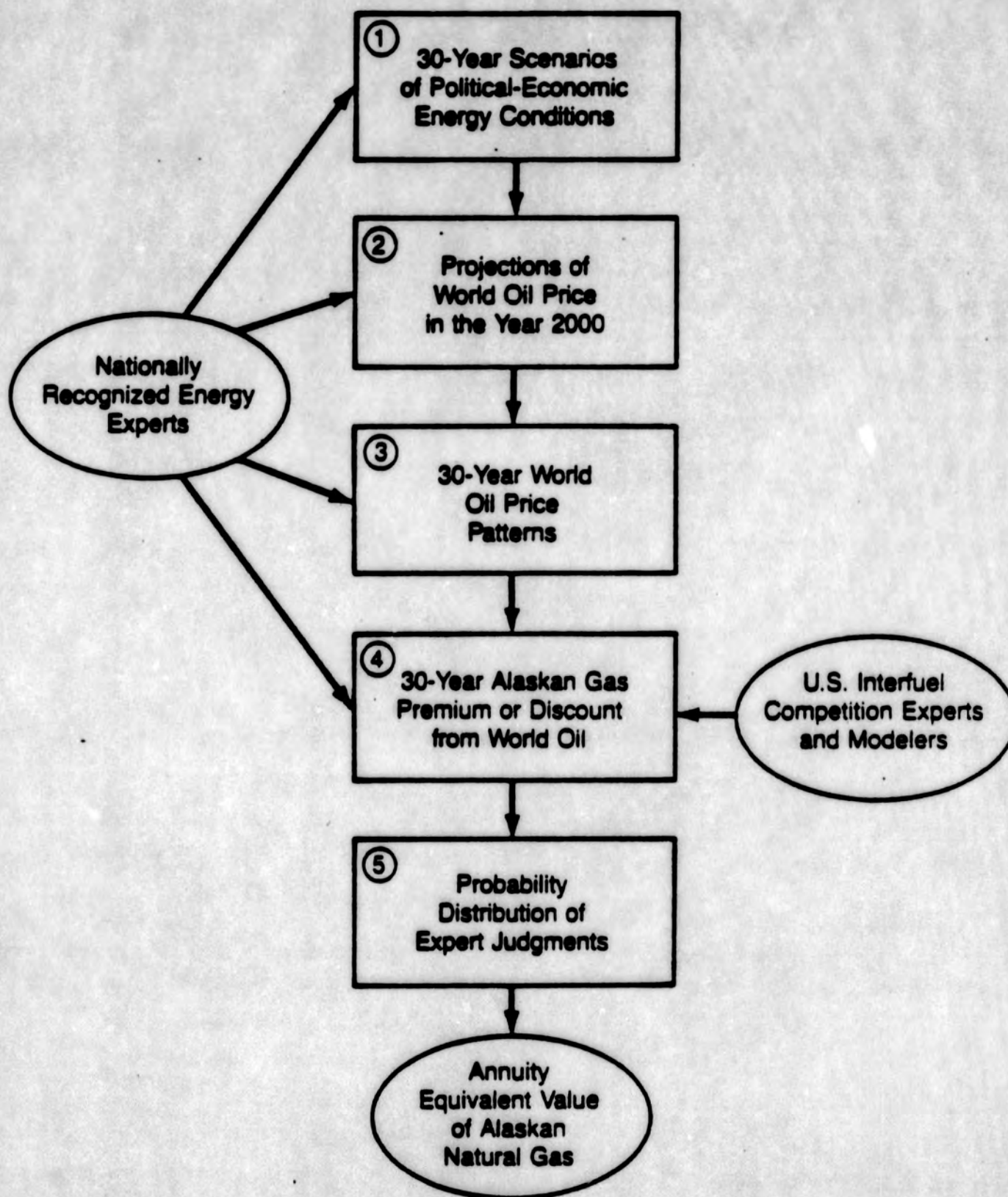
To derive the value of Alaskan gas, we employed the five-step process depicted in Exhibit 1.c. First, the range of possible settings for energy prices was considered by constructing 30-year scenarios of political-economic energy conditions. Second, based on these conditions, a probability distribution on world oil price in the year 2000 was assessed. Third, five 30-year world oil price scenarios were constructed, each corresponding to a price in the year 2000 sampled from the distribution. Fourth, for each world oil price scenario, three gas value scenarios were assessed. Fifth and finally, probability distributions on the levelized value of Alaskan gas were calculated based on the assessments obtained in the previous steps. Each step is further explained below.

Step 1:
Develop Scenarios

During our interviews with individual experts, a series of 30-year scenarios was developed. The scenarios included the experts' assumptions about the most influential factors on general world oil price levels. Typically, the experts considered world economic growth, geopolitical pressures and events (particularly in the Middle East), technological developments, governmental policies, and supply and demand elasticities. They developed at least three scenarios -- a likely scenario, a high energy price scenario, and a low energy price scenario.

Exhibit 1.c

FIVE-STEP APPROACH TO ESTIMATING
VALUE OF ALASKAN NATURAL GAS



To illustrate, low-price scenarios were characterized by many experts as involving a stable Middle East and rapid technological development and/or depression in most industrialized countries and high elasticity of demand. High-price scenarios were generally characterized by international strife, slow technological progress, and environmental barriers to resource development.

Step 2:

Estimate World Oil

Price in the Year 2000

For each of the scenarios defined in Step 1, the experts then developed estimates of world oil price in the year 2000. These estimates for each scenario were made as probability statements to capture the experts' degree of confidence. For example, one expert stated: "Given the low-price scenario, we have one chance in ten that no real growth in oil price will take place."

Using these results, and also considering implicitly the multitude of other scenarios that could unfold, the experts then developed an overall probability distribution on world oil price in the year 2000. Exhibit 1.d shows the result for an expert who believes there is a 10 percent chance that the price will exceed \$114 per barrel in 1980 dollars and a 10 percent chance that it will be less than \$53 per barrel. This expert also considers it equally likely that the price will be above or below \$75 per barrel.

The distributions for all 28 experts are overlaid in Exhibit 1.e. Not surprisingly, a great divergence of opinion exists among these experts. One said the price will not be less than \$150 per barrel, while another contended that it will not be greater than \$70 per barrel. This divergence is due to differing opinions about events in the Middle East, oil discoveries, technological progress, synfuels production, coal development, and future societal values.

Exhibit 1.d

EXAMPLE OF ONE EXPERT'S DISTRIBUTION ON
THE PRICE OF WORLD OIL IN THE YEAR 2000

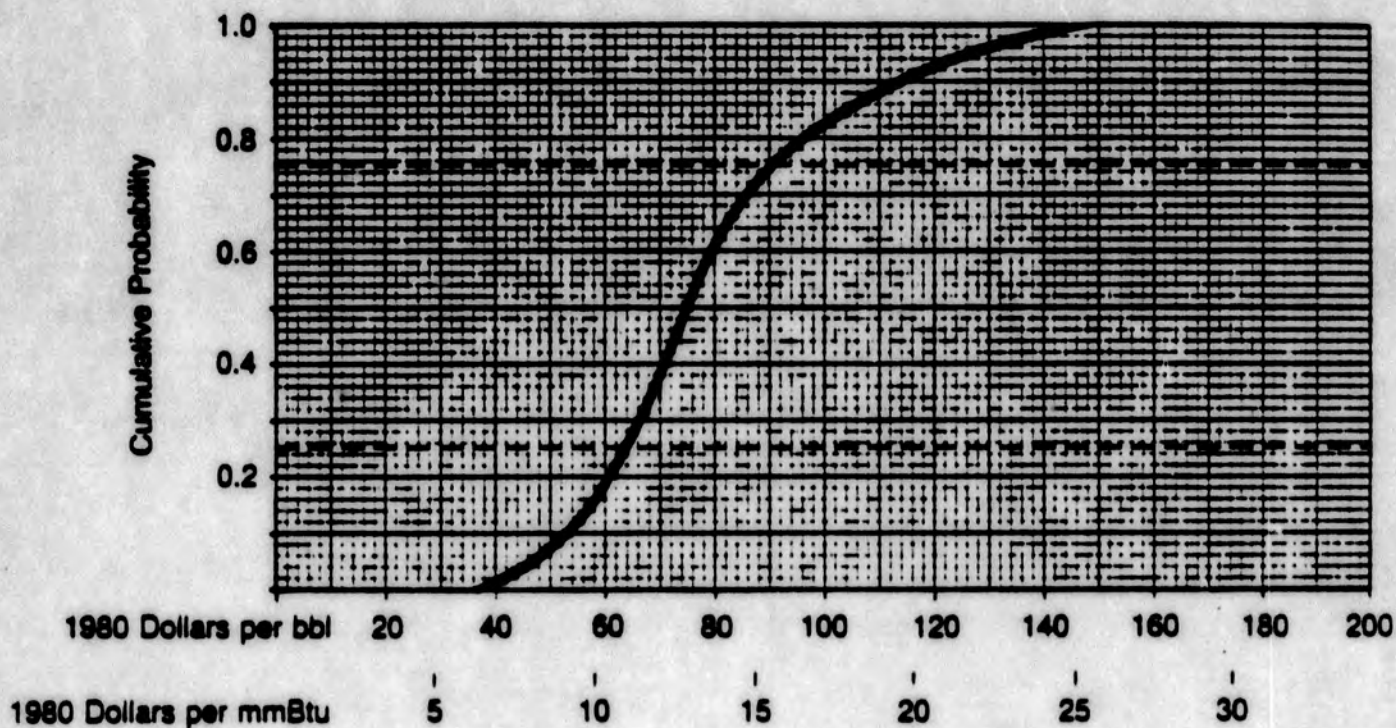
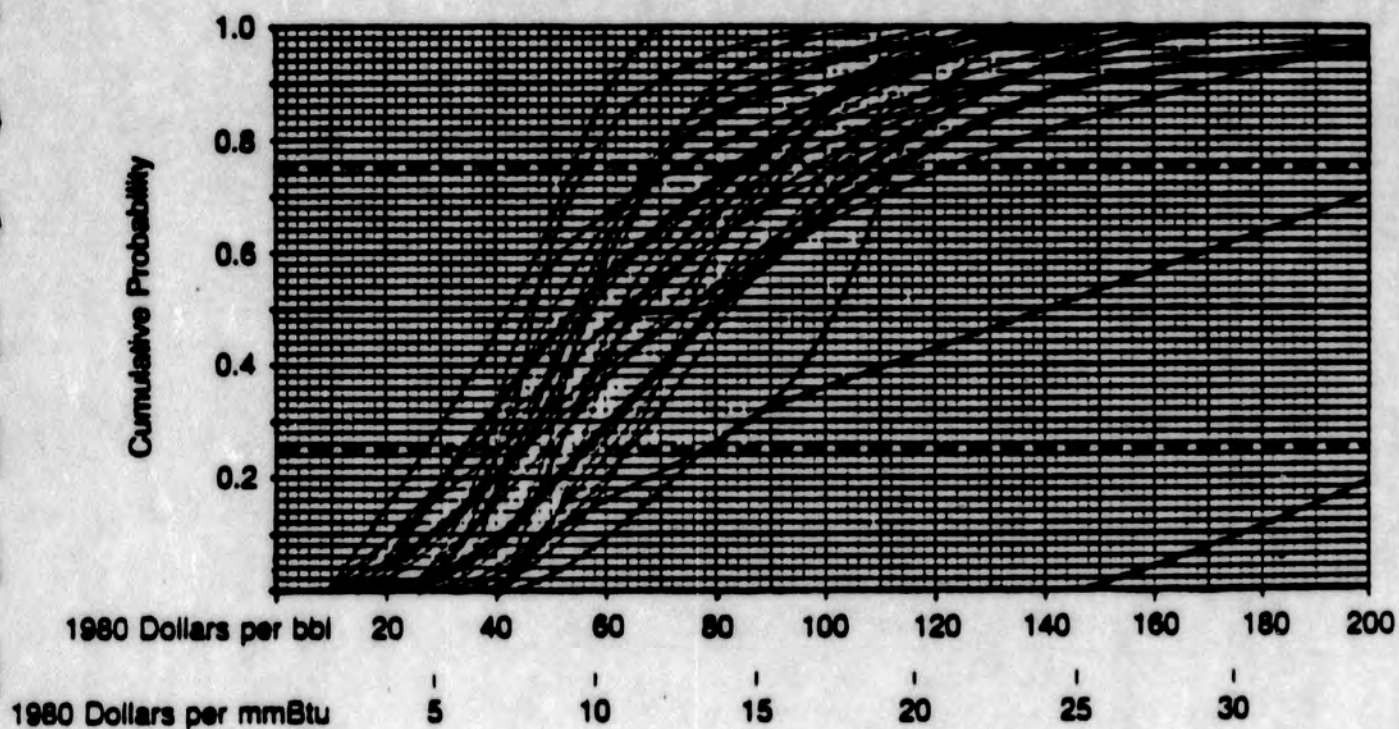


Exhibit 1.e

INDIVIDUAL EXPERTS' AND COMPOSITE
DISTRIBUTIONS ON THE PRICE OF WORLD
OIL IN THE YEAR 2000



The collective judgment of all experts, giving equal weight to each opinion, results in a price ranging from \$22 to more than \$200 per barrel, with an expected value of \$96 per barrel. We can safely say that the experts consider long-term energy prices extremely uncertain. Consequently, any single point estimate is of questionable worth to decision makers.

Most experts were optimistic about the ability of the world economy to cope with less oil. To support this view, they pointed to the relatively minor effect of the loss of Iraqi and Iranian production over the last year. Some, however, considered the world economy less resilient and thought that reduced oil supply combined with higher prices would cause a deep, prolonged world depression. This economic chaos could lead to very low oil prices in the long term. These experts also thought that high oil prices would cause rapid substitution away from oil and gas, thus lowering oil prices.

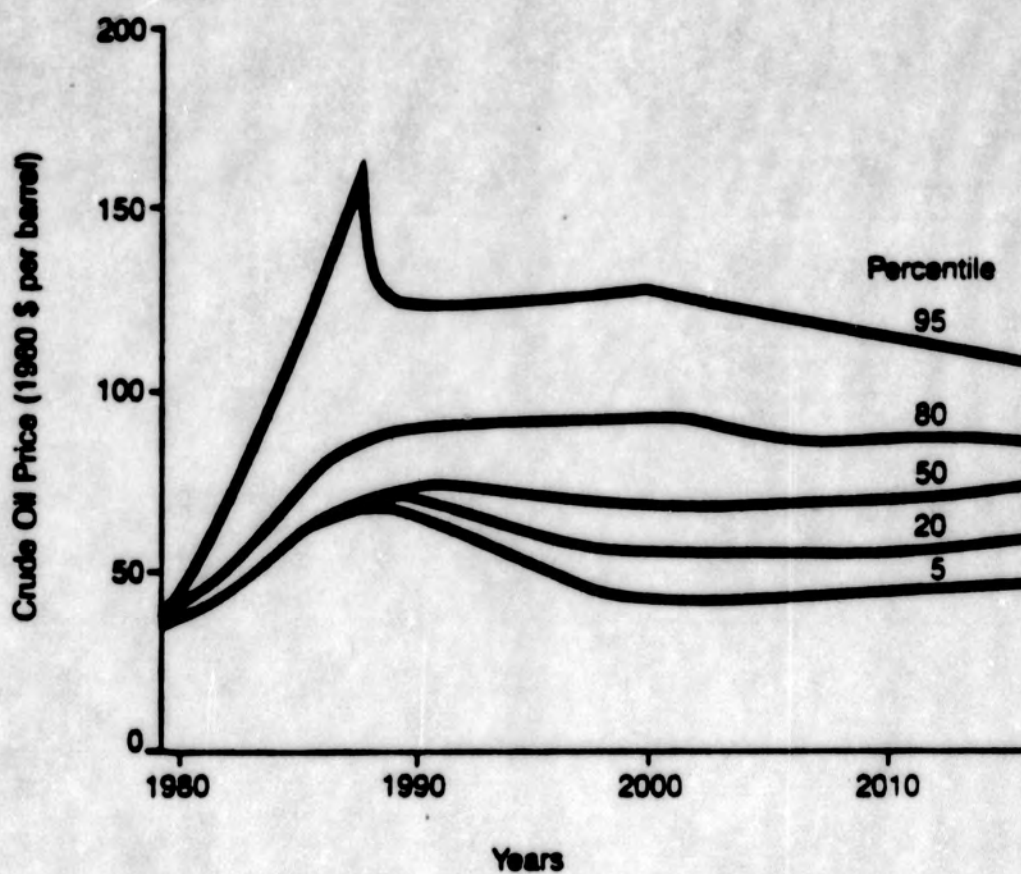
Several experts believe that world oil prices would develop along one of two equally likely scenarios. One scenario is a benign and stable Middle East with relatively high oil production. The other is a turbulent Middle East with major export production shortfalls. The result is a probability distribution on world oil price in the year 2000 that is a composite of two very different distributions, one for each scenario.

Step 3:
Assess World
Oil Price Patterns

In this step, we extended the results of the previous step to cover the entire period between 1980 and 2010. First, we chose five representative prices from the distribution on world oil price in the year 2000. Then, the experts developed a 30-year time pattern of oil prices consistent with each of these prices. If experts felt that significantly different patterns could be consistent with a single price, they were asked to assess a "weighted average pattern." An example of an expert's price patterns is presented in Exhibit 1.f.

Exhibit 1.f

EXAMPLE OF ONE EXPERT'S
30-YEAR WORLD OIL PRICE PATTERNS



Opinions about time patterns for world oil prices also varied considerably. However, most experts felt that prices would increase substantially and that most of this increase would occur between now and the year 2000, with a slow increase or decline beyond the year 2000. This pattern was explained in several ways. First, experts anticipated that new and more efficient energy production and utilization technologies would emerge by the year 2000, thus halting the rise in oil prices. Second, many experts believed that at least one major disruption in the world oil market would occur before the year 2000. However, there were three points of view as to the effect of this disruption on oil prices. Most experts expected that the price would jump and then remain nearly constant until the long term trend caught up, or until there was another disruption. A few foresaw a temporary surge in prices, followed by a return to the trend. And one anticipated that a surge would later cause the price to fall below the trend line.

In addition to these general patterns, two unique forecasts are noteworthy. One expert envisioned a possible future in which the Organization for Economic Cooperation and Development (OECD) would abandon conservation and new technologies and would later be caught unprepared by the price increases of the Organization of Petroleum Exporting Countries (OPEC). In this scenario, OPEC would adopt a benign pricing strategy for the next ten years. This period would be marked by slowly declining world oil prices and followed by aggressively coordinated price hikes, which would result in very high oil prices in the period between 1990 and 2010. Another expert forecasted an attempt by OPEC to achieve a major price increase in the early 1980s, which would prompt extreme reactions by the consuming nations (e.g., mandatory conservation measures or military intervention in the Middle East). After the reaction, demand would drop sharply, OPEC would collapse, and world oil prices would fall accordingly.

Step 4:

Estimate Gas Value Scenarios

For each of the world oil price patterns developed in Step 3, the experts were asked to consider the premium or discount that gas could command in the unregulated U.S. energy markets. The experts considered the factors that

may cause gas to be valued above or below oil on an equivalent-Btu basis. These factors include the cost of fuel conversion, long-term supply and demand situations, air quality standards, and other regulations affecting energy use.

Each expert developed three gas value estimates (10 percentile, 50 percentile, and 90 percentile estimates) for each of the five oil price patterns, leading to 15 gas-value patterns. Again, the experts' opinions about the gas value relative to oil price levels varied considerably over the 30-year period. Generally, the different views hinged on the weight given to the premiums for liquids in the transportation sector and the premiums given to cleanliness and efficiency for the gas. Most experts also took into account the future conversion costs from one fuel to the other.

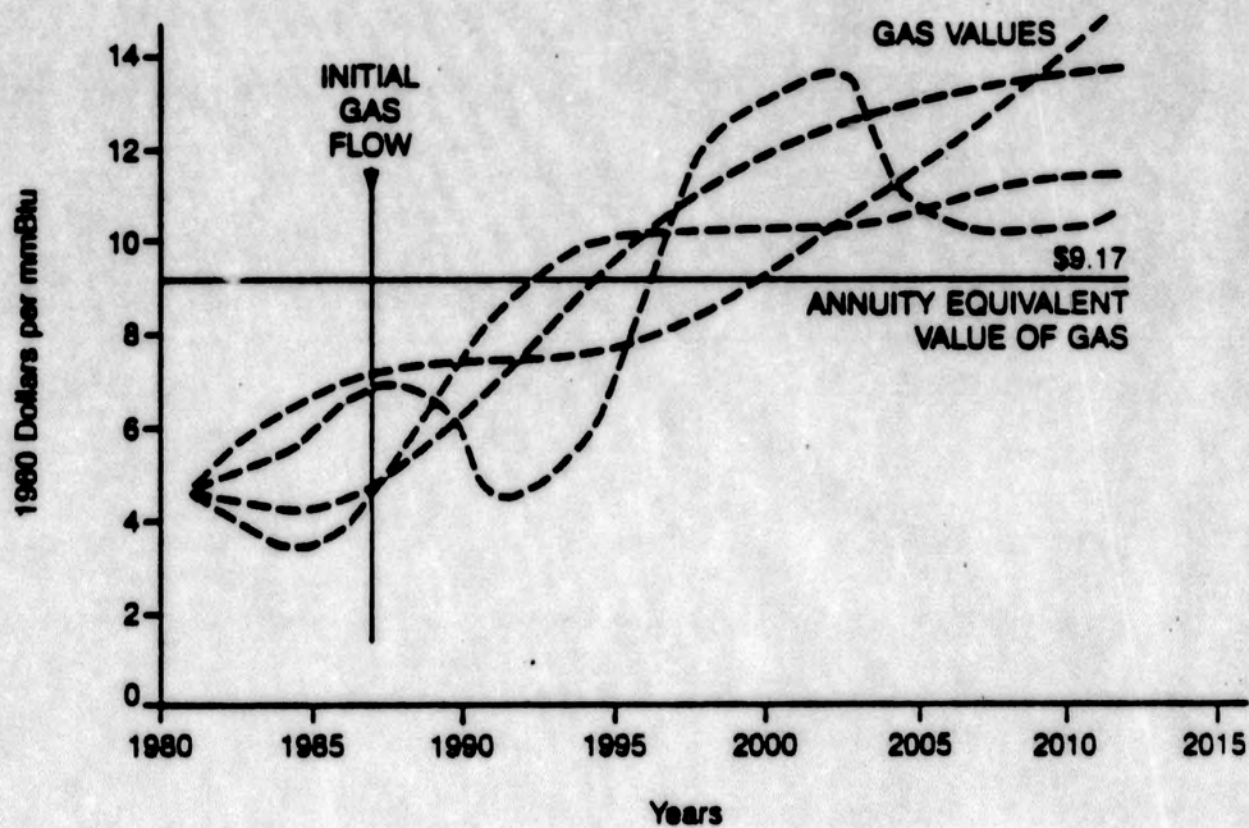
Two camps emerged among the experts: those who considered gas a discounted fuel (especially if oil price level was very high), and those who expected a slight premium for the gas because of its clean-burning characteristics. All experts considered gas value to be linked closely to world oil price.

Step 5:
Develop Probability
Distribution on Gas Value

In the final step, we calculated a probability distribution for each expert on the levelized value of Alaskan gas, as well as a composite distribution. The levelized gas value is a single-number summary of a pattern of values over time. It is a uniform annuity equivalent (i.e., a constant annual value whose present value is the same as a changing pattern). As shown in Exhibit 1.g, a single levelized value may correspond to widely different patterns of values. We chose levelized value as the measure of the value of Alaskan gas for three reasons. First, it can be more readily compared to other energy prices. Second, it can be used to calculate the absolute present value of the gas. Third, it can be represented graphically by a probability distribution.

Exhibit 1.g

RELATIONSHIP BETWEEN GAS-VALUE PATTERNS
AND THE ANNUITY EQUIVALENT VALUE OF GAS



The results obtained in this step are displayed in Exhibit 1.h. The heavy curve is the composite distribution that was obtained by giving each expert equal weight; it is the same as the curve in Exhibit 1.b.

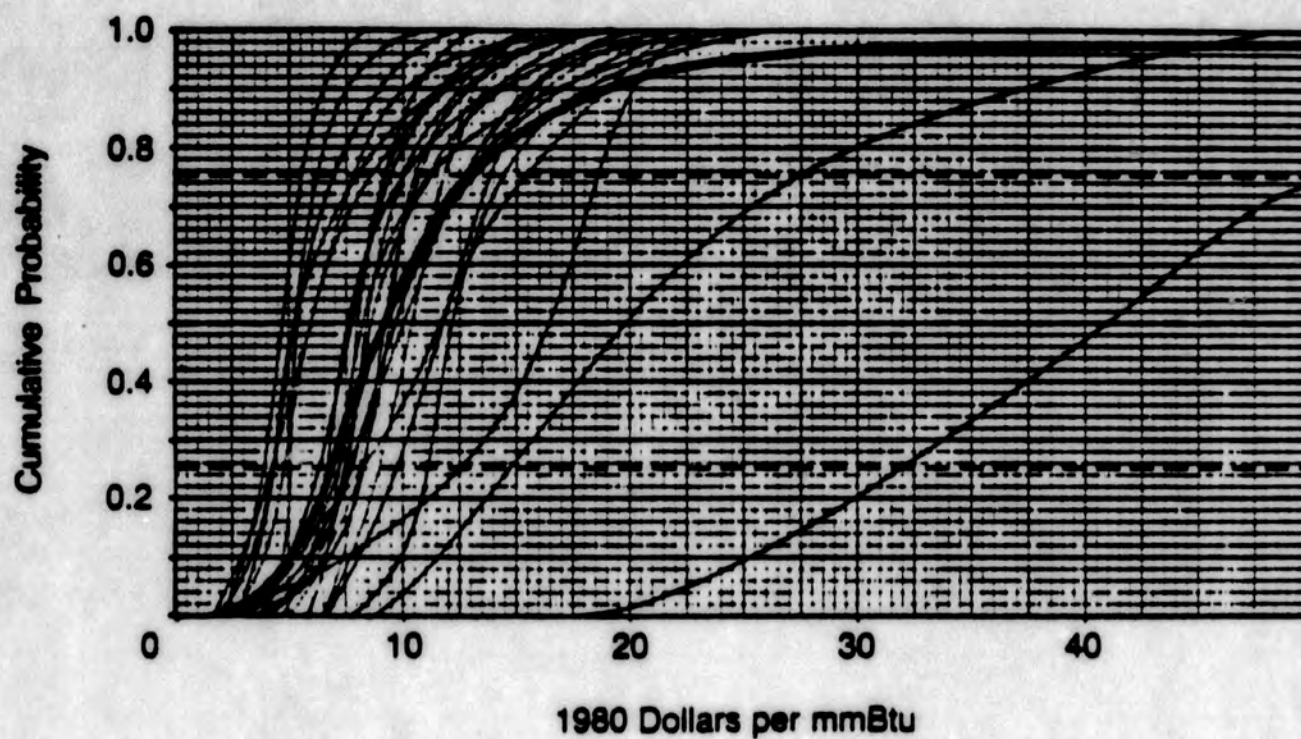
For each expert, the probability distribution on levelized gas value was calculated as follows:

- Each of the 15 gas-value patterns (three for each of the five world oil price patterns) was converted to a levelized value.
- Probabilities were approximated for each of these values, based on the assessments of Steps 2 and 4.
- The distribution was constructed from the probability-value pairs.

The collective judgment was the gas value used for the NNEB analysis presented in Chapter 3. The median value annuity equivalent of \$9.17 per million Btu was used for the base case. Given that the gas value distribution is highly skewed upward with an expected value of \$11.79 per million Btu, this assumption is conservative.

Exhibit 1.h

INDIVIDUAL EXPERTS' AND COMPOSITE
DISTRIBUTIONS ON THE ANNUITY EQUIVALENT
VALUE OF NATURAL GAS



2

ANGTS COSTS

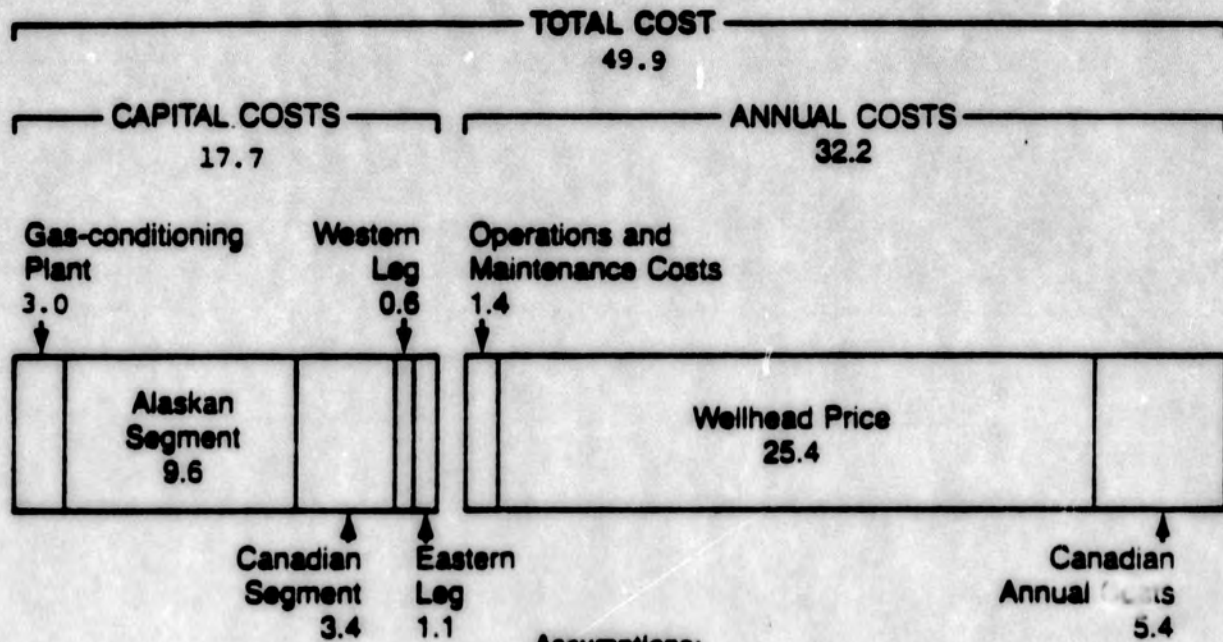
ANGTS is composed of a gas-conditioning facility at Prudhoe Bay and several major pipeline segments that ultimately deliver gas near Chicago and San Francisco. The total cost of delivering the gas to the U.S. consumers is \$73 billion in 1980 dollars. This includes the cost of the natural gas at the wellhead, the capital costs of facilities to condition and transport Alaskan gas, the operating and maintenance costs, and Canadian annual costs. It does not include inflation, financing charges, or the incentive rate of return rate base adjustment. Discounted at a 3 percent real discount rate, the total mid-1981 present value cost is approximately \$50 billion in 1980 dollars. The components of this cost are illustrated in Exhibit 2.a. In this chapter, we present the estimates of the capital and annual costs of ANGTS as provided to RPA by the Northwest Alaskan Pipeline Company.

CAPITAL COSTS

The gas-conditioning facility, the Alaskan segment of the pipeline, and the northern portion of the Canadian segment must be built solely to prepare and transport the natural gas produced at Prudhoe Bay. The southern portion of the Canadian segment and the U.S. Eastern and Western segments of the pipeline will transport both Alaskan and Canadian gas. The combined capital costs attributable to conditioning and delivering Alaskan gas add up to \$19.5 billion in 1980 dollars. Discounted at 3 percent, the present value of these costs is \$17.7 billion. Capital costs represent 34 percent of the total cost to be borne by the United States. They are explained individually below.

Exhibit 2.a

COMPONENTS OF THE TOTAL COST OF
DELIVERED GAS (1980 \$ billions
present value)



Assumptions:

- NGPA Wellhead Price (including 10% Alaskan severance tax).
- No Design and Scope Changes.
- No Regulatory Delays.
- Incremental Capital Costs of Transportation System for Alaskan Gas Only.
- Real Discount Rate of 3%.

Gas-Conditioning Facility

A \$3.3 billion cost is assumed for the gas-conditioning facility in 1980 dollars. The present value cost is \$3.0 billion in 1980 dollars, using a 3 percent real discount rate. This cost represents 17 percent of the capital costs and 6 percent of the total cost of ANGTS.

Alaskan Pipeline Segment

From the gas-conditioning facility at Prudhoe Bay, the Alaskan segment of the pipeline system takes the gas south to Fairbanks and then southeast to the Canadian border. Second to the cost of the gas itself, this segment has the largest cost associated with the project. The capital cost for the Alaskan pipeline segment is \$10.6 billion in 1980 dollars. Using a 3 percent real discount rate, the present value of this cost is \$9.6 billion. The Alaskan pipeline segment accounts for 54 percent of the ANGTS capital costs and 19 percent of the total cost to be paid by the United States for Alaskan gas deliveries.

Canadian Pipeline Segments

From the Alaskan border, the gas is transported southeast through Canada to the United States. The cost of the Canadian pipeline segments is approximately \$5.8 billion in 1980 dollars. However, some of the pipeline capacity will be devoted to carrying Canadian gas. Of the 1179.9 trillion cubic feet per year to be delivered through ANGTS in the Lower-48 states, 406.4 trillion cubic feet (or 34 percent) will be Canadian gas. Accordingly, approximately 34 percent of the Canadian portion of ANGTS is devoted to Canadian gas transportation. The capital cost attributable to Alaskan gas is therefore \$3.8 billion in 1980 dollars. Discounted at 3 percent, the present value of the Canadian capital cost required to transport Alaskan gas is \$3.4 billion in 1980 dollars. The cost of the Canadian pipeline segments is 19 percent of the capital costs and 7 percent of the total cost to the United States.

Lower-48 Pipeline Segments

Near Caroline, Alberta, the Canadian pipeline bifurcates. One segment travels southeast to the Chicago area and the other travels southwest to the San Francisco area. Both of these pipelines will be carrying Canadian gas before the Alaskan flow begins in late 1986. Once Alaskan flow begins, the Eastern and Western segments will carry approximately 64 and 70 percent Alaskan gas, respectively. Of the \$1.8 billion total cost in 1980 dollars of the U.S. Eastern segment, \$1.2 billion is attributable to Alaskan gas. Of the \$0.8 billion total cost in 1980 dollars of the U.S. Western segment, \$0.6 billion is attributable to Alaskan gas. Taken together and discounted with a 3 percent real discount rate, the present value of the cost of these segments is \$1.7 billion in 1980 dollars. The Lower-48 pipeline segments account for 10 percent of the capital costs and only 3.4 percent of the total cost to be borne by the United States.

ANNUAL COSTS

The annual costs include the cost of the natural gas itself, ANGTS operating and maintenance costs, and the Canadian cost of service. These costs amount to \$57.3 billion in 1980 dollars. Discounted at a 3 percent real rate, the present value of these costs is \$32.2 billion. Annual costs represent 65 percent of the total cost for delivered Alaskan gas. They are discussed separately below.

Natural Gas Cost

The natural gas cost at the wellhead is the largest single cost associated with the project. The gas cost is determined by Alaskan severance tax policy, the Natural Gas Policy Act of 1978 (NGPA), and the flow rate into the gas-conditioning facility. Alaska is likely to charge a 10 percent severance tax on the wellhead price of the gas. The NGPA specifically omits Prudhoe Bay gas from deregulation and allows the maximum price of the gas to

rise only with inflation. Consequently, the real cost of the gas will not rise as long as the NGPA is in effect. Finally, the assumed input flow rate is 2.1 billion cubic feet per day beginning in late 1986. The natural gas cost amounts to \$42.1 billion in 1980 dollars, \$22.6 billion greater than all capital costs combined. Using a 3 percent real discount rate, the present value of the natural gas cost at mid-1981 is \$25.4 billion in 1980 dollars. At this discount rate, the cost of the gas represents 51 percent of the total cost.

Operating and Maintenance Costs

Operating and maintenance costs for ANGTS, excluding Canada, are \$2.4 billion in 1980 dollars. These costs were estimated by weighting the costs for each segment by the proportion of Alaskan gas flowing through the segment. They do not include the cost of the pipeline gas used by compressors at compressor stations, which is recognized only by increasing the cost of gas leaving each segment above the cost of the gas as it entered the segment. The present value of the operating and maintenance costs is \$1.4 billion in 1980 dollars, using a 3 percent real discount rate. Using this same discount rate, operating and maintenance costs outside of Canada account for 3 percent of the total cost.

Canadian Annual Costs

Finally, the Canadian annual costs going to the Canadian government and the sponsors of the Canadian segments is approximately \$9 billion in 1980 dollars. These costs represent the difference between the Canadian cost of service (\$12.8 billion) and the Canadian capital costs (\$3.8 billion) and includes Canadian segment operating and maintenance costs (approximately \$0.6 billion). Using a 3 percent real discount rate, the present value of the Canadian cost of service is \$8.8 and of capital costs is \$3.4 billion. Thus, the present value of Canadian annual costs is \$5.4 billion in 1980 dollars. These annual costs must be subtracted from NNEB because they are costs paid by U.S. parties.

3

NET NATIONAL ECONOMIC BENEFITS OF ANGTS

In the two preceding chapters, we presented estimates of the value of the Alaskan gas and the cost of the gas and transportation system. In this chapter, we combine value and cost to derive the NNEB of ANGTS. We begin by reviewing the underlying assumptions in the NNEB estimate, including the use of a 3 percent real discount rate. Finally, we examine the sensitivity of the base case to several important assumptions about the project.

Briefly, the base case present value of the NNEB of ANGTS is approximately \$60 billion in 1980 dollars, assuming a real discount rate of 3 percent. Although this figure is sensitive to several important variables, none of these variables, within a reasonable range, causes it to be negative. Furthermore, the risks of a lower NNEB are outweighed by the potential of a significantly higher NNEB.

THE BASE CASE

Several government agencies, energy companies, and consultants have estimated the NNEB of ANGTS. All of these studies have used similar methodologies. The most recent study concludes that "the ANGTS project would generate overwhelming net benefits to the nation and to each major project participant, including producers, pipelines, consumers, and government."*

* Douglas B. Fried and William F. Hederman, Jr., "Benefits of an Alaskan Natural Gas Pipeline," The Energy Journal, Vol. 2, No. 1, pp. 19-36, 1981. The NNEB estimate in this study was \$22 billion in mid-1980 dollars, using a 6 percent real discount rate and somewhat lower gas values.

The NNEB is derived by subtracting the costs presented in Chapter 2 from the value of the gas presented in Chapter 1. This procedure yields a combined estimate of cost savings to energy wholesalers and consumers, of government tax receipts, and of returns to project investors.

The \$60 billion estimate of the NNEB for the base case is derived as follows:

Components of NNEB	Value (\$ billions)
Value of Delivered Gas	110.0
Capital Costs	17.7
Operating and Maintenance Costs	1.4
Wellhead Price	25.4
Canadian Annual Costs	5.4
Total Cost of Gas	49.9
Net National Economic Benefits	60.1

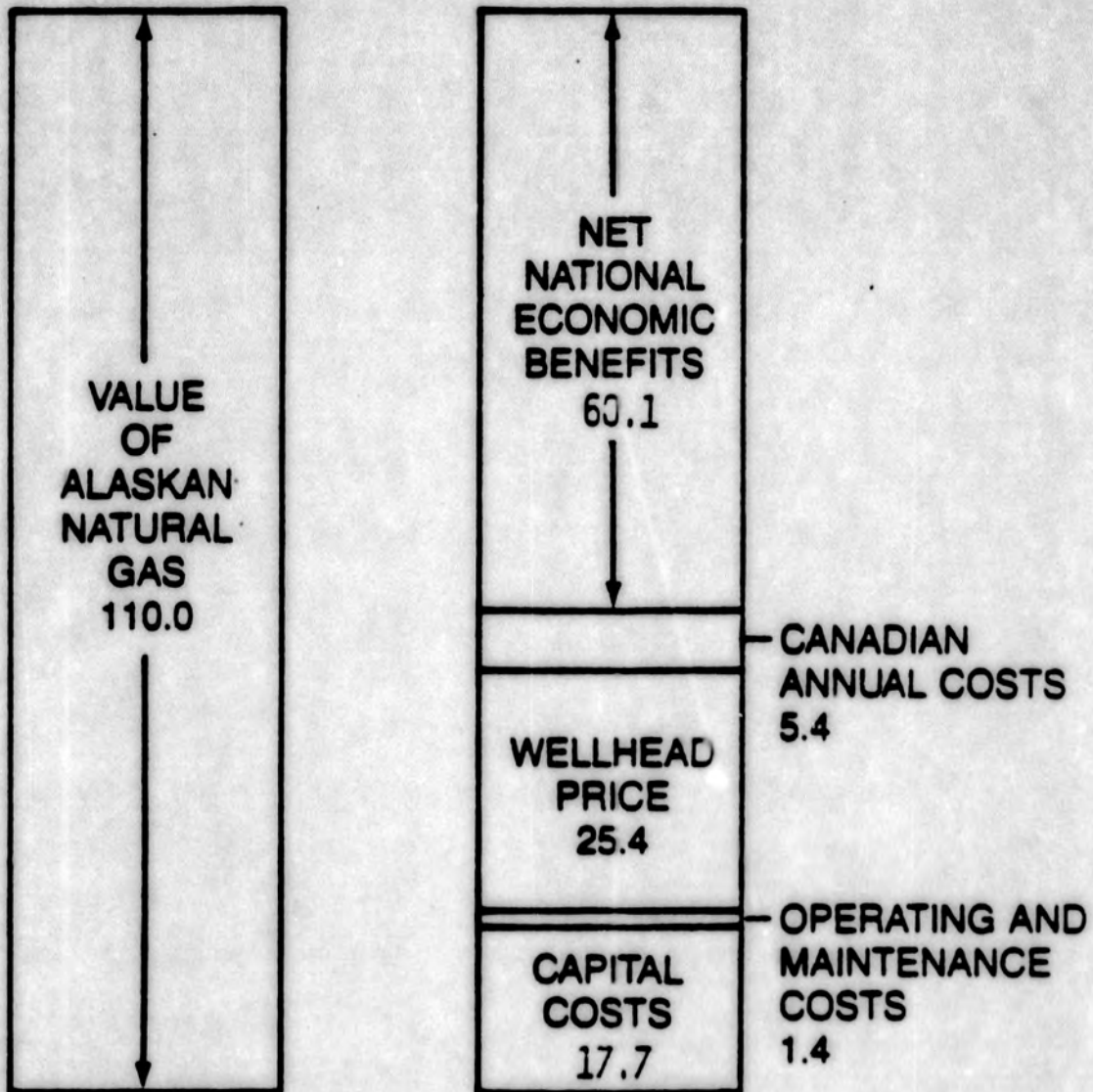
The relative magnitude of these components is displayed in Exhibit 3.a.

This estimate of the NNEB rests on a number of implicit assumptions:

- The gas will ultimately "back out" foreign energy sources or U.S. sources that would have a cost equal to the gas value.
- The gas is valued at the wellhead price before entering the conditioning or transportation system.

Exhibit 3.a

**RELATIONSHIP BETWEEN NNEB ESTIMATE
AND VALUE OF ALASKAN NATURAL GAS
(1980 \$ billions)**



- The availability of the gas does not have a significant impact on overall world energy prices or supply and demand relationships.
- The additional benefits of improved balance of payments and increased energy independence are not included.
- Benefits to contractors and vendors for the construction of the system are ignored.

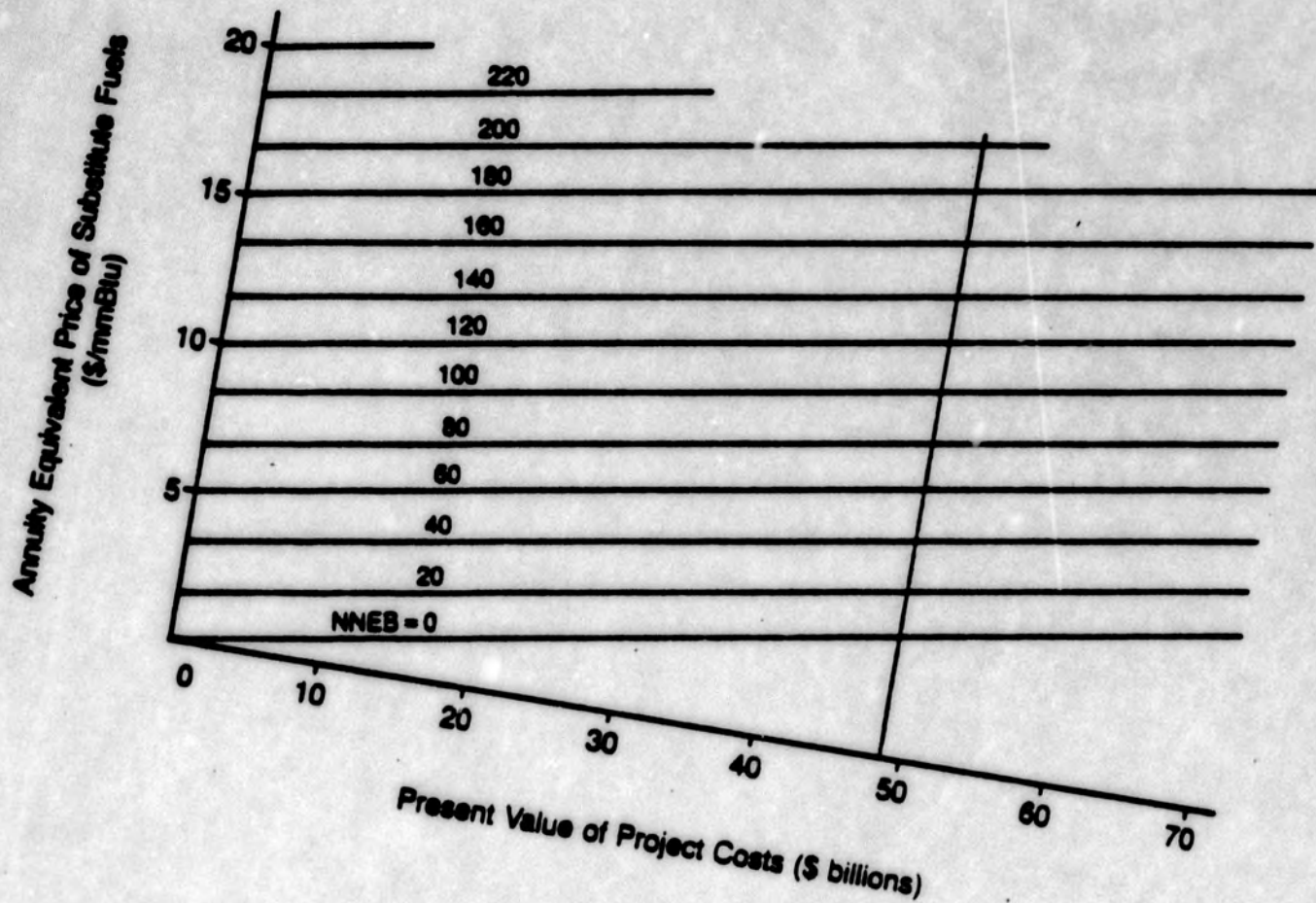
SENSITIVITY ANALYSIS OF THE BASE CASE

In addition to the above implicit assumptions, the specific assumptions that were made for the base case analysis are highly uncertain. For example, the value of the gas, based on the experts' collective judgment, had one chance in ten of being below \$4.94 per million Btu. Moreover, ANGTS is still in an early stage of engineering and its capital costs are not yet definite. Also, if additional reserves are discovered, the delivery volume and the project life could increase significantly.

Beyond these uncertainties, considerable controversy has surrounded the selection of an appropriate discount rate. Briefly, the real rate of return on risk-free private investments such as U.S. Treasury Bills is an upper bound on the appropriate rate. This is because ANGTS will provide a hedge against the risks of present dependence on imported energy. Historically, U.S. Treasury Bills have yielded less than a 3 percent real rate of return.

In Exhibit 3.b, we present the relationship of the NNEB estimate to changes in project cost and gas values. The base case is identified on the graph. Note that a \$10 billion increase in project costs could be completely offset by a \$0.83 per million Btu increase in gas value. This relationship explains why ANGTS is so attractive today -- even though cost estimates have grown significantly. The doubling of oil prices in late 1979 more than made up for the increase in project cost estimates.

Exhibit 3.b
NNEB FOR DIFFERENT PROJECT
COSTS AND GAS VALUES



The degree of uncertainty in gas value and project cost is demonstrated in Exhibit 3.c. As shown, uncertainty in the NNEB ranges from a high of \$170 billion to a low of \$5 billion. The NNEB corresponding to the modal value of the gas is \$40 billion. For the expected gas value, the NNEB is \$90 billion.

The other key sensitivities are given in Exhibit 3.d. As evident in this table, the value of the gas is by far the single most important factor. It can increase the NNEB by \$110 billion or decrease it by \$51 billion. Changes in the U.S. project cost have a dollar for dollar effect on the NNEB. However, even major changes in costs claim only a small fraction of the NNEB.

Although a higher discount rate does not seem justified, the NNEB is clearly sensitive to the discount rate assumption. A higher discount rate decreases the value of future energy cost savings and therefore reduces the NNEB significantly. The present value of project costs also drops, but less since the capital costs are expended much earlier. This relationship is presented in Exhibit 3.e. Even at the most extreme assumption of a 10 percent real discount rate (above inflation), the NNEB exceeds \$13 billion.

The NNEB analysis was performed in real 1980 dollars. Changes in inflation rate assumptions would have no effect on the NNEB value.

Exhibit 3.c
NNEB OVER EXTREME RANGES OF
PROJECT COSTS AND GAS VALUE

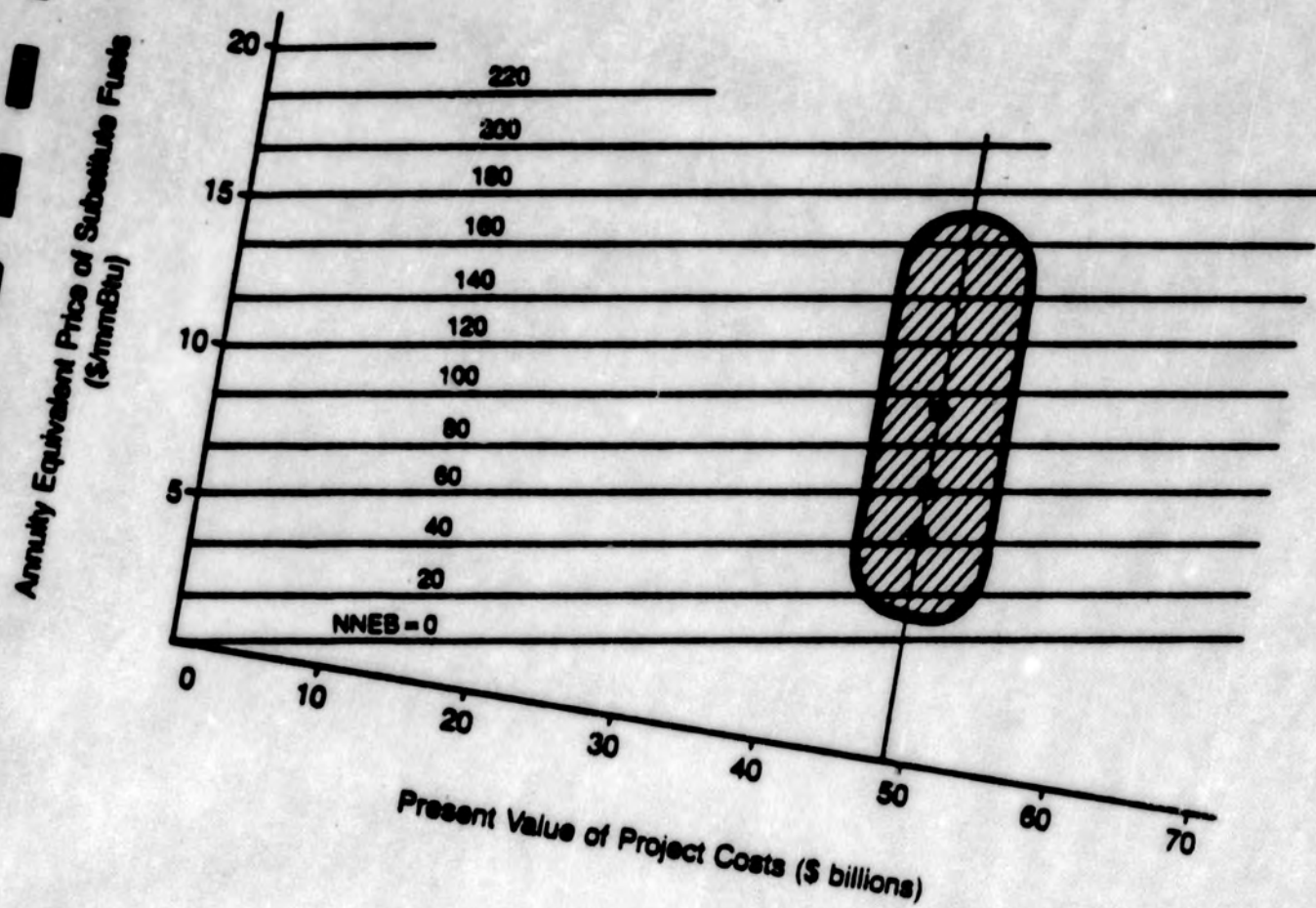


Exhibit 3.d

**SENSITIVITY OF NNEB TO
CHANGES IN MAJOR ASSUMPTIONS**

Assumption	Sensitivity Scenario			Change in NNEB From Base Scenarios (1980 \$ billions)	
	Low	Base ^a	High	Low	High
Value of Gas (\$/mmBtu)	4.94	9.17	18.32	-51	+110
Project Cost ^b (1980 \$ billions)	55	50	-	-5	-
Real Discount Rate (%)	6	3	-	-29	+54
Project Life (years)		25	50	-	+39

a. Median NNEB of \$60 billion.

b. Assumes a 30 percent capital cost increase. Also assumes no increase in Canadian annual costs or taxes as a result of a cost increase.

Exhibit 3.e

SENSITIVITY OF NNEB TO
REAL DISCOUNT RATE
(1980 \$ billions)

	Real Discount Rate (%)			
	0	3	6	10
Value of Gas	187.2	110.0	67.9	39.0
Project Costs	<u>-73.0</u>	<u>-49.9</u>	<u>-36.4</u>	<u>-25.9</u>
NNEB	114.2	60.1	31.5	13.1

* Based on median estimate of gas value (\$9.17 per mmBtu).

APPENDIX H

JOINT STATEMENT OF INTENTION

June 1980

JOINT STATEMENT OF INTENTION

Atlantic Richfield Company, Exxon Corporation, and The Standard Oil Company (Ohio) (the Producers), and Alaskan Northwest Natural Gas Transportation Company, a partnership (Alaskan Northwest), enter into this Joint Statement of Intention at the request of the United States Department of Energy.

Preliminary Recitals

The Producers and Alaskan Northwest have a common interest in the efficient and cost-effective construction and operation of the Alaska Natural Gas Transportation System (ANGTS) including the conditioning plant at the earliest practicable date. Alaskan Northwest has developed a construction schedule for the ANGTS which would result in completion of the system in 1985.

The facilities to be constructed in the State of Alaska which are necessary to placing the ANGTS in service require immense capital investment, and private sector lenders who will be asked to advance funds for the construction of Alaskan facilities will require reasonable assurance that the facilities will be completed and placed in service, and their debt serviced.

The President's Decision and Report to Congress describes the plan for private financing of the ANGTS to be implemented by Alaskan Northwest. Alaskan Northwest has indicated that the Alaskan segment of ANGTS can be financed in the private sector, if there is meaningful participation by the Producers in the financing structure. The Producers have indicated willingness to participate in a substantial way with Alaskan Northwest in the financing of the Alaskan pipeline and conditioning plant upon reasonable terms and conditions, provided they are not placed in the position of becoming, in effect, the ultimate guarantors of completion of the ANGTS and provided that their financial exposure is effectively limited.

In an effort to move forward in surmounting the acknowledged difficulties presented by this project, the parties have entered into a Cooperative Agreement for continued design and engineering of the Alaskan gas pipeline and the conditioning plant which will prepare natural gas produced from the Prudhoe Bay unit of Alaska for transmission through ANGTS.

Statement of Intention

It is the mutual objective of the Producers and Alaskan Northwest that the ANGTS be completed and placed in service at the earliest practicable date and, accordingly, the Producers and Alaskan Northwest intend to use their best efforts, on a joint and cooperative basis, to expedite design, engineering and cost estimation.