HE COMPTROLLER GENERAL

ort To The
orable Ted Stevens
ed States Senate

THE UNITED STATES

Issues Facing The Future Use Of Alaskan North Slope Natural Gas

The North Slope of Alaska contains over 26 trillion cubic feet of natural gas. In 1977, the President and the Congress approved construction of a 4,800-mile gas pipeline to bring this gas to U.S. consumers by 1983. However, completion of the project is not now expected until late 1989 at the earliest.

This report examines the status and outlook for the Alaskan gas pipeline (the Alaska Natural Gas Transportation System). It also evaluates the pros and cons of (1) alternative systems to deliver this gas to market, including a gas pipeline within Alaska for export of liquefied natural gas; (2) processing the gas in Alaska by converting it to methanol and petrochemicals for export; and (3) using the gas within Alaska.

UNITED STATES GENERAL ACCOUNTING OFFICE

GAO/RCED-83-102
MAY 12, 1983

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON D.C. 20548

B-209475

The Honorable Ted Stevens
The Assistant Majority Leader
United States Senate

Dear Senator Stevens:

This report summarizes the results of our examination of the marketing and financing obstacles encountered by the sponsors of the Alaska Natural Gas Transportation System. As requested in your letter of June 30, 1982, this report also examines five alternatives for transporting and using the abundant natural gas reserves of the Alaskan Arctic.

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 7 days from the date of the report. At that time, we will send copies to Members of Congress and other interested parties and make copies available to others upon request.

Charles A. Bowsher
Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT
TO THE HONORABLE TED STEVENS
UNITED STATES SENATE

ISSUES FACING THE FUTURE
USE OF ALASKAN NORTH
SLOPE NATURAL GAS

D I G E S T

In 1977, the President and the Congress approved construction of a 4,800-mile gas pipeline system--the Alaska Natural Gas Transportation System--from the North Slope of Alaska through Canada to California and Illinois. The system was intended to deliver natural gas from the Alaskan Arctic by 1983, especially reserves from the Prudhoe Bay field, estimated at 26 trillion cubic feet. The system is estimated to cost about $24.8 billion (1982 dollars) to construct. With interest costs and inflation, the system's total costs exceed $40 billion.

In 1982, construction was completed on part of the southern portion of this pipeline (1,512 miles from Alberta, Canada, to Iowa and Oregon) to deliver Canadian gas. Completion of the rest of the pipeline has been delayed until at least late 1989 because of marketing and financing uncertainties.

The Assistant Majority Leader, U.S. Senate, asked GAO to review various alternatives to the system and to examine its status and outlook as well as means to expedite its completion.

MARKETING THE SYSTEM'S GAS IS THE MAJOR OBSTACLE TO ITS COMPLETION

Before the Alaska Natural Gas Transportation System's completion can be assured, its participants--a consortium of gas pipeline companies and the three North Slope gas producers--must secure a gas market and develop a financial plan. The system's participants have been unable to guarantee a market for the North Slope gas largely because its delivered price is estimated to be considerably more than alternative gas supplies. In addition, the lower 48 States are experiencing a surplus of gas supplies and adequate supplies are expected to continue throughout the decade under current regulations. Timing of the project will depend on whether a clear need for the gas can be demonstrated in 1990 and beyond.

GAO/RCED-83-102
MAY 12, 1983

Beyond the marketing problems, a plan to finance the system's Alaskan segments has not been finalized. Although the system's participants have preliminarily pledged various amounts of support to the project, at least $5 billion in additional financial support would be needed for the Alaskan facilities before funds are made available by lenders. Even if this credit gap is filled, the amount of private capital available in world markets to finance the system is uncertain. (See p. 19.)

The Canadian segment of the system will face financing problems as well. Increasing Canadian pipeline costs, and limits on the ability of lenders to participate in financing more than one segment of the system contribute to its uncertain financing outlook. (See p. 22.)

A VARIETY OF MEASURES MAY BE NEEDED TO FINANCE THE SYSTEM

None of the options to expedite the system which GAO examined is an immediate remedy for the project's problems. Many require further investigation or legislative changes, and all depend ultimately on when additional gas supplies are needed to meet demand. A combination of the following measures, which appear to have the greatest potential impact, is likely to be needed to improve the project's viability:

--Alternative pricing mechanisms. Mechanisms to reduce the high price of the gas in its initial years may be necessary. For example, use of a level pricing concept, whereby the delivered gas is priced at a flat and eventually declining rate, is being studied by project participants. To reduce the gas price, investors would have to defer some expected return from the project in its early years. GAO's discussions with the financial community indicate that this may be difficult, particularly to Canadian investors. (See p. 33.)

--Wellhead price decontrol or total deregulation of the project. These regulatory changes would remove some Federal controls over the system. Participants might have more incentive to ensure that the system is constructed at minimum costs so that they would receive the best return on their investment. (See p. 36.)

--System design change. Increasing the pipeline's pressure, and thereby its capacity, could accommodate future increases in gas discoveries and shipment to markets in the lower 48 States over the long term. This change could have transportation cost advantages by reducing the per-unit gas cost. At the same time, however, construction costs would increase. (See p. 38.)

--Expansion of project participants. More project participants would enhance the system's credit support by providing additional financial backing for the project's construction. GAO found that new participants are unlikely to join the project in the near term. Sufficient additional credit support appears unlikely from financial institutions, oil and gas producers, pipeline companies, and the State of Alaska. (See p. 40.)

ALTERNATIVES TO USE OR TRANSPORT NORTH SLOPE GAS MUST OVERCOME SEVERAL OBSTACLES

GAO examined a number of alternatives to use or transport the Alaskan gas. GAO's analysis of these alternatives indicates that many have similar disadvantages largely because of: (1) the expense and size of any project to move the gas more than 800 miles over difficult terrain to a market and (2) marketing problems. As part of GAO's review, engineering consultants were hired to review the viability and cost of certain alternatives to the system. Cost estimates for alternatives presented in this report are based on preliminary design, not detailed engineering, and could be subject to major cost variances. Moreover, because the system's cost estimates are based on more engineering and design than the alternatives, the system's estimates should be considered to be more reliable. Direct comparisons of the system's costs and those of alternatives presented in this report should not be made.

Exporting the gas from south Alaska: an all-Alaskan pipeline system

The major alternative to the system is the construction of an 800-mile gas pipeline located entirely within the State of Alaska. North

Slope gas would be transported to a southern Alaskan port, then liquefied and shipped by tankers to domestic or foreign markets. In addition to the pipeline, this alternative requires the construction of new processing and dock facilities, as well as the use of new or existing tankers at a preliminary cost estimated at $13 billion to $18 billion (1982 dollars).

Proponents of this alternative believe that Asia, primarily Japan, is a logical export market for Alaskan natural gas, especially since no facilities to process the liquefied natural gas exist on the U.S. West Coast. However, there is a poor outlook for this foreign market. Several countries are already developing export projects and have contractual commitments to deliver natural gas to Japan. As a result, Japan could have sufficient supplies of imported natural gas through 1990 and beyond and would be unlikely to need gas from Alaska. Only if the high demand forecasts of the Japanese Government were realized would a likely market for Alaskan gas appear in Japan. (See p. 58.)

A second obstacle is that exports of Alaskan natural gas are limited by law to relatively small amounts unless the President determines that larger exports are in the national interest. (See p. 61.)

Transportation proposals to ship the gas directly from the Arctic, by using ice-breaking tankers or submarines, would require construction of expensive offshore terminals on the North Slope, as well as the use of ships that are largely untested for liquefied natural gas transportation. These proposals have not been proven to be economically attractive and are unlikely near-term alternatives to the system. (See p. 64.)

<u>Processing the gas within the State: methanol and petrochemical alternatives</u>

Producing methanol (methyl alcohol, an alcohol fuel) from North Slope gas is not a viable alternative, at least through 1990. Alaskan methanol would cost more to produce and deliver to U.S. markets than methanol from current sources. GAO estimates that, based on one contractor's study, an Alaskan methanol project would cost about $22 billion (1982 dollars) to construct, because of the expense of constructing 37 methanol plants which would be needed to process all of the gas. Most proposals for a methanol project have assumed these plants would be constructed on the North Slope and the methanol would be shipped through the existing Alaskan oil pipeline. World methanol markets are currently experiencing a surplus, largely because methanol use is primarily limited to the chemical industry. To absorb the volume of Alaskan methanol produced, widespread new uses for methanol, especially as a fuel, would be needed to significantly increase demand. Until a long-term, low-cost methanol supply can be guaranteed, however, such demand is unlikely to develop. (See p. 76.)

The use of North Slope gas as a raw material input for a petrochemical industry in Alaska is also not a viable alternative to the system. World petrochemical markets are depressed and predicted to remain so through 1990. GAO's analysis indicates that new Alaskan production is unlikely to find a market. Moreover, foreign countries offer petrochemical companies incentives to maintain production in their countries. Alaska has comparatively high gas and construction costs that would have to be offset for an Alaskan project to be competitive. (See p. 80.)

Using the gas within the State of Alaska

Prudhoe Bay gas that is being produced with the oil and is not consumed as fuel on the North Slope is being injected back into the field. Essentially, this recycles the gas back to its source. According to State of Alaska analyses, gas reinjection can continue indefinitely without damaging the oil or ultimate recovery of the gas for future sales. (See p. 90.)

Gas is also currently consumed as fuel for oilfield operations on the North Slope. Over the next 25 years, these activities are expected to consume about 12.5 percent of the recoverable gas or 3.3 trillion cubic feet. (See p. 91.)

In order for Alaskans to use the North Slope gas within the State for power or fuel, a system to transport the gas over 400 miles to its closest market must be constructed at considerable expense. Since Alaska's small population has access to a variety of energy supplies, North Slope gas must compete with alternative sources. It is unlikely that power or heating demand for this gas would exceed 18 billion to 20 billion cubic feet per year. In total, therefore, only about 23 percent of the North Slope gas--6 trillion cubic feet--could be needed within Alaska for oilfield, power, and fuel supplies over the next 25 years. (See. p. 85.)

If a gas transportation system is not available to bring the gas to market, the gas could be used for fuel in an advanced oil recovery technology. Use of this technology to recover certain kinds of heavy oil that are too thick to flow and cannot be economically produced from the North Slope might increase future in-State gas consumption. Testing of various technologies is in the initial stages. More testing will be needed before the demand for gas in such a recovery program is known. (See p. 88.)

CONCLUSIONS

Timing of the completion of the Alaskan Natural Gas Transportation System depends upon resolution of its marketing and financial problems. The project will require clear market signals and a combination of special financing measures to be viable. At a time of such uncertainty over future gas markets, consumers may not be willing to pay for the system's gas in 1989. Declining oil prices and continuing gas surpluses in the lower 48 States could continue to delay the system's completion.

At the same time, however, alternatives to the system are no more viable. The only near-term use for Alaskan natural gas may be its continued reinjection.

Any major project to move North Slope gas should meet the following conditions to be viable and acceptable to the financial community:

--The product should have a firm, long-term market and a price that minimizes the use of subsidies or assistance to maintain its competitiveness without distorting the market.

--The economics of the project must be attractive, and its financial backers must be strong enough to attract necessary funding.

Specifically, an adequate return to lenders should be assured throughout the project's entire life and the project's sponsors should provide guarantees for completion of the project's construction.

COMMENTS

Because this report is not an evaluation of a Federal agency's performance, GAO did not seek any agency's official comments. However, GAO convened a panel of experts representing a broad range of economic, engineering and regulatory backgrounds to review and comment on a draft of the report. (See app. VII.) Comments on chapters 2 and 3 were received from the Northwest Alaskan Pipeline Company, the operator for the companies sponsoring the system. (See app. XIII.)

The panel largely discussed the relative emphasis of the issues presented in the report as well as specific comments on how data were presented. Their comments have been considered and changes reflecting their concerns have been made where appropriate.

Northwest Alaskan officials believe that the natural gas industry is experiencing a crisis period. Over the long-term, however, they feel Alaskan gas continues to be needed to meet demand in the lower 48 States. When market conditions change, Northwest believes prospects for financing the system will likewise change.

As stated frequently in this report, markets beyond 1990 are not accurately predictable. GAO recognizes that the financing outlook for the system could change if a dramatic change in market conditions were to occur.

Contents

ABBREVIATIONS

AAPS	All-Alaskan pipeline system
ANGTA	Alaska Natural Gas Transportation Act
ANGTS	Alaska Natural Gas Transportation System
ARCO	Atlantic Richfield Company
bcf	billion cubic feet
bcfd	billion cubic feet per day
Btu	British thermal unit
CRS	Congressional Research Service
DOE	Department of Energy
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GAO	General Accounting Office
GNP	gross national product
IDB	industrial development bond
IEE	Institute of Energy Economics (Japan)
IROR	incentive rate of return
KEPCO	Korean Electric Power Corporation
LNG	liquefied natural gas
Mmbd	million barrels per day
mcf	thousand cubic feet
Mmcfd	million cubic feet per day
MITI	Ministry of International Trade and Industry (Japan)
MmBtu	million British thermal units
MMT	million metric tons
MTPD	metric tons per day

NGL	natural gas liquid
NGPA	Natural Gas Policy Act
NPC	National Petroleum Council
NPRA	National Petroleum Reserve--Alaska
OCS	Outer Continental Shelf
OPIC	Overseas Private Investment Corporation
OTA	Office of Technology Assessment
psig	pounds per square inch gage
SOHIO	Standard Oil Company of Ohio
TAGS	Trans Alaska Gas System
TAPS	Trans-Alaska Pipeline System
Tcf	trillion cubic feet
USGS	United States Geological Survey

CHAPTER 1

INTRODUCTION

In 1968, oil and gas were discovered at Prudhoe Bay on the North Slope of Alaska. The recoverable associated [1] and gas cap reserves are estimated at 26 trillion cubic feet (Tcf), or about 13 percent of total U.S. gas reserves. Nine years later, a system to deliver this gas to Midwestern and Western U.S. markets--the Alaska Natural Gas Transportation System (ANGTS)--was approved by the President and the Congress. ANGTS is a planned 4,794-mile overland pipeline system (of which 1,500 miles has been completed) to transport gas from Prudhoe Bay south to Delta Junction, Alaska, and then eastward through Canada. (See fig. 1.) ANGTS is currently sponsored by a group of 10 U.S. and Canadian gas pipeline companies and the 3 oil companies which own the Prudhoe Bay gas. (See ch. 2.)

Although ANGTS was originally scheduled to deliver gas to U.S. markets in 1983, the project's completion has been delayed until at least late 1989 by marketing and financing problems. These delays have led to discussion of alternative delivery systems for North Slope gas. For example, the State of Alaska has authorized three studies to evaluate options to use the gas. This report examines a variety of alternative systems to use or transport Prudhoe Bay gas.

EVOLUTION OF THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

The Congress has taken a series of actions to authorize and expedite construction of a natural gas transportation system from Alaska. The following chronology briefly describes the major congressional actions on ANGTS. (See app. II for a detailed discussion.)

1976 The Congress enacts the Alaska Natural Gas Transportation Act (ANGTA), setting up a procedure for selection of a natural gas pipeline system.

1977 The Congress adopts the President's "Decision and Report to the Congress" selecting the Alcan Pipeline Company's overland pipeline system through Canada. (The rights to the system were later assigned to the partnership of the Alaska Northwest Natural Gas Transportation Company.)

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[1]Associated gas is gas which is found in a reservoir that also contains oil with which it is in contact. Sometimes used to refer to the gas in the oil solution as distinguished from that in the gas cap.

1977 The United States and Canada agree to (1) nondiscriminatory treatment for all hydrocarbon pipelines between the United States and Canada and (2) principles governing the construction and operation of ANGTS.

1978 The Congress enacts the Natural Gas Policy Act (NGPA) providing for rolled-in pricing [2] of Alaska natural gas with lower 48 State supplies and establishing a maximum wellhead price [3] for Prudhoe Bay gas.

1980 The Congress passes a concurrent resolution affirming its commitment to the ANGTS project.

1981 The Congress passes a resolution waiving certain provisions of the President's decision and other laws to expedite private financing for ANGTS.

1982 The Tax Equity and Fiscal Responsibility Act of 1982 is enacted, allowing ANGTS' sponsors to continue to deduct interest and taxes incurred during construction of the project.

ESTIMATES OF FUTURE ALASKAN GAS RESOURCES AND NEED FOR A TRANSPORTATION SYSTEM

Onshore and offshore Alaska are anticipated to contain an abundance of natural gas, including known reserves and estimated resources. Reserves are part of the broader category of resources. [4] A resource is either identified or undiscovered. A reserve is defined as that portion of an identified resource which can be economically extracted.

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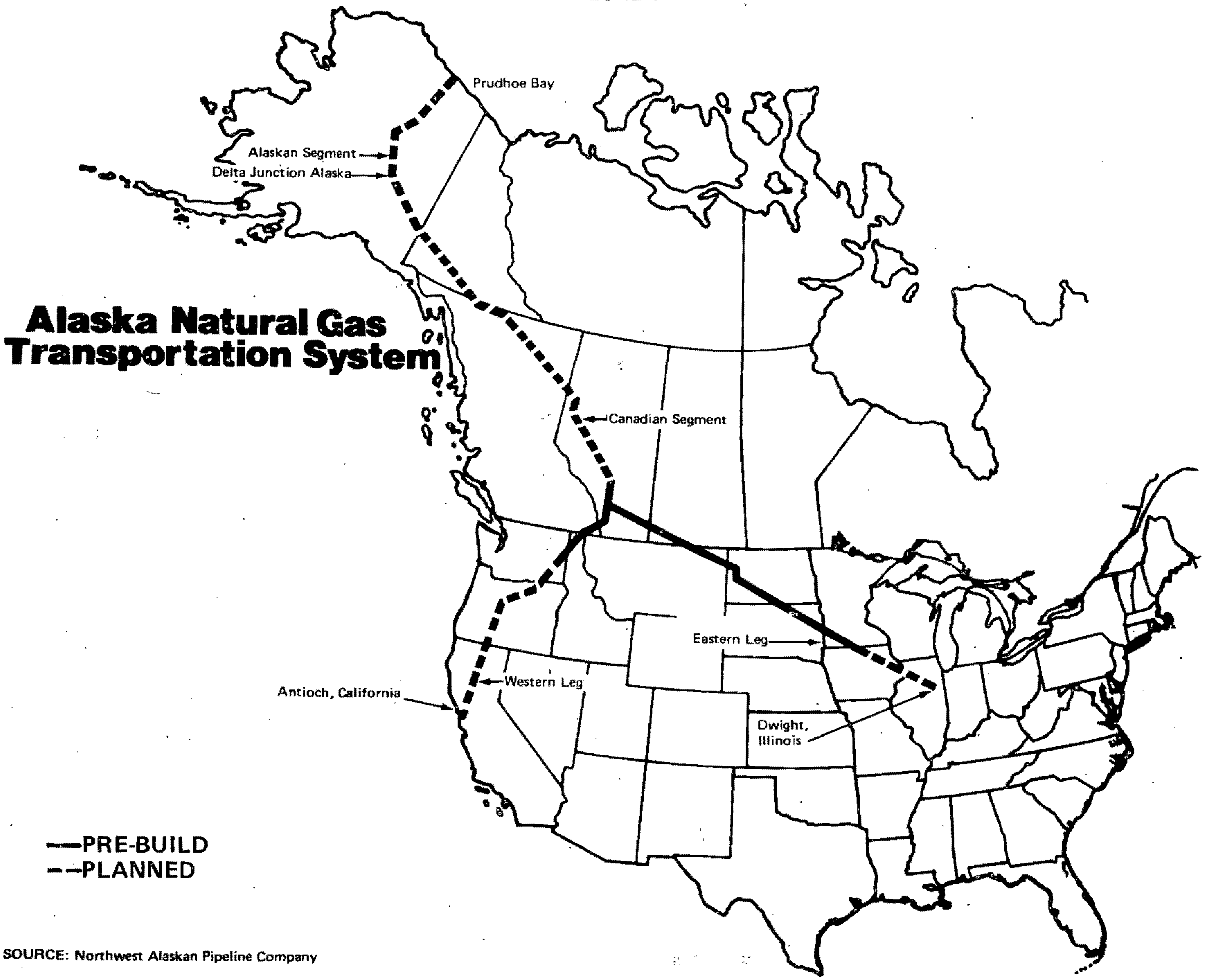
[2]Rolled-in pricing is a method of pipeline gas pricing based on averaging the price of all existing natural gas contracts within a certain market area. See NGPA, section 208.

[3]Wellhead price is the price received by the oil or gas producers for sales at the well. See NGPA, section 109(b).

[4]Resources are concentrations of solid, liquid, or gaseous materials in or on the earth's crust in such form that economic extraction of the material is currently or potentially feasible. An identified resource is a specific accumulation of resources whose quality and quantity are estimated from geologic evidence supported, in part, by engineering measurements. An undiscovered resource is a quantity of a resource estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.

FIGURE 1



SOURCE: Northwest Alaskan Pipeline Company

Natural gas resources that are undiscovered account for the larger portion of the resource potential in the Alaskan Arctic. In 1981, the U.S. Geological Survey (USGS) announced its latest estimates of undiscovered recoverable resources for onshore and offshore areas of the United States, including Alaska.[5] For the onshore North Slope of Alaska,[6] USGS estimated that 31.8 Tcf of undiscovered gas resources were available for economic recovery. The Beaufort Sea was estimated to contain an additional 39.3 Tcf of undiscovered recoverable natural gas resources.

The National Petroleum Council (NPC), in December 1981, issued its own estimates of Arctic resources. In its report, "U.S. Arctic Oil and Gas," NPC estimated that the onshore Arctic area of Alaska contained approximately 35.3 Tcf of undiscovered potentially recoverable natural gas. The Beaufort Sea was estimated to provide an additional 33.0 Tcf of natural gas resources.

Combining the recoverable 26 Tcf of natural gas reserves in the Prudhoe Bay field with undiscovered resources, the Arctic regions of Alaska could provide the United States with nearly 100 Tcf of natural gas as shown below:

Source	Undiscovered recoverable resources Onshore	Undiscovered recoverable resources Offshore	Onshore reserves	Total
	----------	(Tcf)	----------	
USGS	31.8	39.3	26	97.1
NPC	35.3	33.0	26	94.3

The 100-Tcf estimate (which equals about 5 years of U.S. consumption) is often used to illustrate the need for some form of a dedicated Alaskan gas transportation system to access this gas for U.S. consumers. Those developing the oil and gas deposits on the North Slope argue that the United States should be increasing its overall ability to move these resources out of the Arctic. Industry believes such a transportation capability would in turn be an incentive for more gas exploration.

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[5]USGS, "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States," Circular 860.

[6]Alaska's North Slope is the area bordering the Beaufort Sea from the Arctic coastal plain to the southern foothills and the Brooks Mountain Range. (See map in app. III.)

CHANGES IN U.S. GAS MARKETS SINCE 1977

Natural gas accounts for about 27 percent of the Nation's primary energy use. The President's 1977 decision found that an Alaskan natural gas project was desirable because demand for domestic gas was seen to be increasing, while production in the lower 48 States was tapering off and oil imports were at record levels. The report found that "* * * the addition of Alaska gas to domestic production will make a substantial contribution toward closing the gap between natural gas supply and demand." This gap was forecast to occur by 1990.

The timing of the President's decision on ANGTS closely followed the extremely cold winter of 1976-77--a period of acute natural gas supply shortages in some parts of the United States. Recently, however, the United States has experienced natural gas surpluses largely because of higher gas prices which have increased drilling and discoveries, reduced the consumption of natural gas, and increased the competitiveness of other fuels, particularly residual fuel oil. Widespread gas surpluses represent dramatically changed circumstances from projections made when ANGTS was approved.

Price trends since 1977

The natural gas industry is undergoing a period of transition as it moves from a regulated to a partially deregulated market. [7] NGPA substantially changed Federal natural gas regulations by providing for the gradual deregulation of natural gas prices. Generally, the purpose of NGPA was to allow higher prices for "new gas" [8] in order to increase supply while, at the same time, continuing Federal price regulation on "old" gas to keep consumer prices as low as possible.

Rising gas prices during this period have contributed to decreased gas consumption and some industrial switching from gas to oil-fired boilers in the United States. Until recently, interstate pipelines could generally sell as much gas as they could provide. Recently, however, some pipelines have exercised clauses in their contracts to reduce their purchase of gas found too expensive to market, voluntarily reduced their gas deliveries, and renegotiated the purchase obligations of their contracts. These efforts by industry are an attempt to reduce volumes and gas prices, and otherwise adjust to current gas surpluses.

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[7]See U.S. General Accounting Office, "Natural Gas Price Increases: A Preliminary Analysis," GAO/RCED-83-76, Dec. 9, 1982, and "Information on Contracts Between Natural Gas Producers and Pipeline Companies," GAO/RCED-83-5, Feb. 22, 1983.

[8]"New" gas is gas from wells drilled after 1977, whereas "old" gas is gas under contract as of the date of the act.

The future of gas markets has been the subject of a variety of speculation, particularly regarding prices beyond the 1990's. Any project to use the Prudhoe Bay gas would be coming on line during this period and is likely to face substantial marketing uncertainties.

In addition, ANGTS was conceived as a project to supply energy competitive with rising oil prices. However, a decline in real (constant dollar) oil prices began in 1981. The recent global oil surplus and the present price decline were not anticipated by many Government, private, and industry forecasts. Given uncertainty over future oil prices,[9] projects delivering high-priced gas to the lower 48 States which depend on rising energy prices to be economically competitive have become less attractive to industry.

OBJECTIVES, SCOPE, AND METHODOLOGY

On June 30, 1982, the Assistant Majority Leader, United States Senate, asked us to do an independent analysis of alternative uses and delivery systems for North Slope gas. (See app. I.) Specifically, he requested that we analyze the possibility of

--an all-Alaskan pipeline for conversion into liquefied natural gas (LNG) for domestic use or exportation (see ch. 4),

--using the gas to create methanol for delivery in the lower 48 States or abroad (see ch. 5),

--using the gas for petrochemicals within or outside Alaska (see ch. 5),

--using the gas within Alaska for power or other fuel supplies (see ch. 6), and

--using the gas to recover heavy oil from the West Sak formation in the Kuparuk field in Alaska (see ch. 6).

In addition to these five alternatives, he later asked that we examine the status of ANGTS and various changes to the project that have been suggested to assist its completion. We analyzed three additional options for the gas--continued reinjection of the gas, flaring the gas, and converting the Trans-Alaska (oil) Pipeline System (TAPS) to a gas pipeline. (See ch. 6.)

[9]See U.S. General Accounting Office, "An Analysis of Natural Gas Pricing Policy Alternatives," GAO/RCED-83-23, Feb. 3, 1983.

We attempted to evaluate the merits of each alternative to ANGTS on economic, environmental, engineering, and legal grounds. These are the key factors used in past studies of Alaskan transportation systems. The emphasis of our analysis has been on ANGTS, an all-Alaskan pipeline, and methanol because experts felt these are the most viable gas uses. We did not evaluate the national security/national defense implications of the alternatives or the motive of "energy independence" because this is largely immeasurable and has overridden economic considerations in the past. Moreover, in its original recommendation on proposed Alaskan natural gas transportation systems, the Federal Power Commission (FPC) [10] concluded that "national security issues are a wash" between overland pipelines such as ANGTS and an all-Alaskan pipeline for LNG transportation. FPC also concluded that no evidence had been presented that a project deserves preference on the basis of national security. This FPC conclusion was based on an evaluation of pipelines to deliver gas to U.S. markets. A foreign market for the gas might involve different national security considerations. Such an evaluation, however, is beyond the scope of this report.

Both the Congressional Research Service and the Office of Technology Assessment completed studies for the 1981 congressional hearings on the methanol alternative to ANGTS, which we have used in our analysis. The Congressional Research Service also has periodically analyzed issues associated with ANGTS. [11] Our last report on ANGTS was issued in 1979. We looked at the status of the project at that time and discussed a possible framework for Government's response to any request for Federal financial assistance for the project. [12] As mentioned in previous footnotes, we have also issued several recent reports on the changing nature of the U.S. gas industry.

Methodology

Our analysis of the alternatives drew upon reports and other information from governmental, industry, State of Alaska,

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[10] Most of the functions of the Federal Power Commission were transferred to the Federal Energy Regulatory Commission, effective Oct. 1, 1977, as a result of the Department of Energy Organization Act, P.L. 95-91.

[11] Congressional Research Service, "Major Issues Associated with the Alaska Natural Gas Transportation Waivers," Dec. 1981, and "Alaskan Natural Gas: When and How?" Jan. 1983.

[12] "Issues Relating to the Proposed Alaska Highway Gas Pipeline Project," EMD-80-9, Oct. 26, 1979.

academic, and other private sector sources. A variety of studies have been done on alternative transportation systems since the 1970's. Our objectives were to assimilate, synthesize, and update the costs and findings of these reports through the gathering of additional data and to present the pros and cons of these alternatives.

In order to benefit from as many previous analyses as possible, we asked the North Slope producers to provide us with data from their studies on alternatives to ANGTS. Some data were provided to us under a pledge of confidentiality and, as such, their sources cannot be disclosed in our report.

We interviewed all participants in the ANGTS project (see ch. 2) as well as representatives from major oil companies and gas pipeline companies which are not members of ANGTS.[13] We met with officials of the Federal Energy Regulatory Commission (FERC); the Office of Federal Inspector for the Alaska Natural Gas Transportation System; the Departments of Commerce, Energy (DOE), the Interior, State, the Treasury, and Transportation; the Environmental Protection Agency (EPA); the Office of the Special Trade Representative; the International Trade Commission; and DOE's Alaska Power Administration. In Alaska, we contacted the State Commissioner of Natural Resources, Department of Revenues, Department of Fish and Game, Department of Environmental Conservation, the Alaska Power Authority, and a variety of regional corporations and municipal interests. Throughout our work, we also maintained contacts with the Governor's Economic Committee on North Slope Natural Gas and the State of Alaska Task Force on Alternative Uses of North Slope Natural Gas.

We were asked to analyze the possibilities for exporting liquefied natural gas, methanol, and petrochemicals. To determine what type of market may exist in the Far East for Alaskan gas, we contacted the Central Intelligence Agency, the Japanese National Oil Company, Japanese trading companies and utilities, and the Korean Ministry of Energy and Resources. Similarly, to assess the possible effects on Canada of abandoning the ANGTS project, we met with Canada's Chairman of the National Energy Board, the Northern Pipeline Minister, and representatives of the Northern Pipeline Agency. Our assessment of the financing difficulties facing ANGTS and any alternative project is based on interviews with officials from U.S. and Canadian banks which

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[13]Specifically, we contacted the oil companies which had actively bid for leases in the recent Beaufort Sea Outer Continental Shelf (OCS) sale (Sale 71) and the 10 largest interstate gas pipeline companies which are not now members of ANGTS. (See app. IV.)

have been advisors to ANGTS, as well as major institutional investors and investment bankers.

To evaluate and update the engineering feasibility and economics of three individual alternatives, we employed the services of three consultants.[14] These consultants were asked to update data provided in previous studies on alternative transportation systems for Alaskan gas and provide estimates on the cost of these systems. Engineering consultants were used to evaluate the all-Alaskan pipeline and methanol alternatives because we determined, on the basis of advice from experts, that these were the most competitive full-scale uses for Alaskan gas. An economic consultant was used to evaluate using the gas within Alaska because little previous analysis was available to us on this question.

We provided economic and financing assumptions for these consultants' work. (See app. V.) The inflation and interest rates used are averages of three econometric forecasts of the implicit GNP deflator. We recognize that estimated project costs can be highly sensitive to changes in inflation assumptions. For example, for ANGTS, a 1-percentage-point increase in the rate of inflation adds about $1 billion to the project's costs in current-year dollars. Therefore, other estimates of the systems we looked at could be higher or lower, depending upon their basic economic assumptions.

The consultants were not asked to compare the merits of one alternative versus another. Rather, our staff made this comparison by analyzing the consultants' report findings. (See app. VI for a more detailed description of each consultant's report.)

The cost estimation work presented in this report for the all-Alaskan gas pipeline and methanol alternatives is based on conceptual engineering design. These estimates are not the result of in-depth engineering design and, as a result, are highly approximate. (According to experts, the confidence interval placed on conceptual cost estimates is ± 30 to 40 percent at best.)[15] Far more thorough study and testing would be

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[14]An all-Alaska pipeline--Parsons Brinckerhoff Quade and Douglas, New York, N.Y.

Methanol--Dr. Carl Thomas, Department of Chemical Engineering, University of Tennessee.

In-State use of the gas--Arlon Tussing, ARTA, Inc., Seattle, Washington.

[15]Rand Corporation, "Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants," Sept. 1981.

required if the private sector decided to pursue construction of one of these systems. As a result, some degree of cost escalation should be anticipated in any preliminary proposals to move North Slope natural gas.

Moreover, comparing the cost of the ANGTS system with those of alternatives is difficult. ANGTS has had more than 4 years of study and millions of dollars of detailed engineering design behind it. The ANGTS pipeline estimates have been evaluated by the Office of the Federal Inspector and FERC and should be considered more reliable than preliminary study estimates. (The confidence interval for an engineering design estimate is generally ± 5 percent at best.)

In the past, we have stated that "* * * an Arctic project's first and subsequent cost estimates should be viewed with skepticism," [16] especially since these estimates may omit or inadequately allow for problems during construction. A 1979 Rand Corporation study [17] found that factors which change project costs include changing the scope of the project; deviating from an optimal construction schedule; poor management and organization; and other factors concerning availability of labor, materials, and services. In 1981, Rand further determined that most of the variation in cost estimates is due to the level of new technology involved in the project, the degree of project site definition, and the project's complexity. The report recommended that

> "* * * straight forward comparisons of capital costs and performance between systems at different stages of development or with different amounts of unproven technology cannot (or at least should not) be made." [18]

We believe the arctic environment adds to the uncertainty surrounding construction of even a known technology. Therefore, we have not presented a direct comparison of the more advanced ANGTS project with an all-Alaskan pipeline or other proposals based on conceptual design. Given these caveats, however, we believe cost estimates of the alternative systems can be used as indicators of the level of investment needed to move the Prudhoe Bay gas.

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[16]"Lessons Learned from Constructing the Trans-Alaska Oil Pipeline," EMD-78-51, June 15, 1978.

[17]Rand Corporation, "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants," July 1979.

[18]Rand Corporation, "Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants," Sept. 1981.

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Comments on a draft of our report were not requested from any Federal or State agency, since this report is not an evaluation of a Federal or State agency's performance. Moreover, no Federal agency has responsibility for selecting or evaluating alternative projects. Rather, a panel of experts from a variety of backgrounds was convened to review and comment on our draft report.[19] We convened this meeting to ensure that important points had not been overlooked or given undue emphasis in our report.[20] The fact that we gave the panel's comments careful consideration does not necessarily mean that the members endorse our conclusions. (See app. VII for a list of participating panelists.) The panel's concerns were on the emphasis of certain issues in the draft and how data were presented. Changes have been made in the text to incorporate their suggestions where appropriate. In addition, comments were also received from the Northwest Alaskan Pipeline Company on chapters 2 and 3, which discuss the status of the ANGTS project. A copy of Northwest's comments has been included as appendix XIII to our report.

We began our review in August 1982 and completed our analysis of alternatives in January 1983. Updating this analysis and additional work evaluating the final reports of the State of Alaska's two task forces and the Alaska Power Authority was completed in March 1983. This review was performed in accordance with generally accepted government audit standards.

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[19]Parts of our report are also based on analyses by two GAO consultants: Mr. David Hickock, Director of the University of Alaska's Arctic Environmental Information and Data Center and Mr. Sam Van Vactor, Economist.

[20]Ch. 7 was completed following our review panel meeting and has not been reviewed by these experts.

CHAPTER 2

STATUS OF THE ALASKAN

NATURAL GAS TRANSPORTATION SYSTEM

The Alaskan Natural Gas Transportation System faces continued marketing and financial uncertainties. Since the project's conception, its estimated costs have risen to the point where North Slope gas is expected to sell for considerably more than alternative gas supplies in the lower 48 States. As a result, the project sponsors have found it difficult to obtain long-term contracts for purchasing Alaskan gas at this time. With the exception of the southern portion of the pipeline (which was pre-built to deliver Canadian gas), the system's completion has been delayed until at least late 1989.

Both the Alaskan and Canadian segments of the project are likely to continue to face financing problems because of (1) problems in obtaining markets for the gas, (2) inadequate credit support, and (3) the question of available capital to finance the project. About $3.3 billion has been invested in the ANGTS project to date, primarily to construct southern portions of the pipeline in the lower 48 States and Canada. Participants are likely to seek recovery of any funds spent on the Alaskan segment and portions of the unbuilt Canadian segment if the pipeline is not completed as planned.

BACKGROUND

Prudhoe Bay natural gas is almost completely owned and controlled by three major oil producers: Atlantic Richfield Company (ARCO), Exxon Corporation, and Standard Oil Company of Ohio (SOHIO). [1] In addition, the State of Alaska has a 12.5-percent royalty share of the gas. The 1981 congressional waiver package allows the producers an equity ownership in the pipeline system as well, subject to FERC's approval and consideration of antitrust laws by the Justice Department.

A group of pipeline companies have joined together to purchase and ship Prudhoe Bay gas. In March 1978, a subsidiary of the Northwest Energy Company and five other pipeline company subsidiaries formed a partnership (the Alaskan Northwest Natural Gas Transportation Company) to plan, design, secure financing for, construct, own, and operate the project's Alaskan segment. Five other subsidiaries of major gas pipeline companies joined the partnership in 1979-80, and two companies subsequently withdrew. Currently, nine companies [2] are members of

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[1]Hereafter referred to as the North Slope producers.

[2]Usually referred to as the sponsors.

the Alaskan Northwest consortium. The following is a list of the parent companies and their subsidiaries which are members of the partnership:

--Pacific Gas and Electric (Calaska Energy Co.).

--Columbia Gas System Service Corporation (Columbia Alaskan Gas Transmission Corp.).

--InterNorth, Inc. (Northern Arctic Gas Co.).

--Pacific Lighting Corporation (Pacific Interstate Transmission Co.).

--Panhandle Eastern Pipeline Company (Pan Alaskan Pipeline Co.).

--Texas Eastern Gas Pipeline Company (Tetco Four, Inc.).

--United Gas Pipeline Company (United Alaska Fuels Co.).

--TransCanada Pipe Lines, Limited (TransCanada Pipelines Alaska, Ltd.).

--Northwest Energy Company (Northwest Alaskan Pipeline Co.).

Neither Northwest nor TransCanada plans to purchase North Slope gas, but rather are participating in the project as an investment. The Canadian segment of the line will be built by Foothills Pipe Line, Ltd., of Yukon, Canada.

The ANGTS system is designed to transport pipeline quality gas, i.e., raw gas that has been purified [3] and separated from some liquids, compressed to a specified pounds-per-square-inch gage (psig) pressure, and chilled. Therefore, the first element of the system's facilities is a gas conditioning plant on the North Slope, which is designed to produce about 2 billion cubic feet per day (bcfd) of gas for transport.

The Alaskan segment of the pipeline carries the gas 743 miles to the Canadian border. The Canadian pipeline segment is 2,023 miles long, and the lower 48 States system an additional 2,028 miles.

In September 1981 and September 1982, construction of portions of the U.S. Western and Eastern Legs, respectively, together with portions of the Canadian segment, were completed.

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[3] Impurities such as water, sulfur, hydrogen sulfide, oxygen, and carbon dioxide have been removed. Propane, pentane, butane, and other liquids have been separated from the gas as well.

These parts of the system, often called the "pre-build," are 1,508 miles long, or about 32 percent of the ANGTS project's mileage. (See fig. 1.) Canadian gas is currently being shipped to the Eastern and Western United States through the pre-build.

Delay in construction schedule has postponed ANGTS completion

In April 1982, the ANGTS consortium announced a 2-year delay in the project's construction schedule, thus postponing initiation of pipeline service to the fall of 1989. The lead time for ANGTS is 5 to 6 years; construction is scheduled over a 4-year period, with an initial period for planning and design work beginning in 1984. Studies are underway by the sponsors to evaluate the possibility of completing this planning and design work in 1 year, thereby reducing the project's lead time. At a May 1982 FERC conference on the project's status, the partnership listed the factors affecting the project's delay: the current, short-term excess world energy supply; depressed crude oil prices; lower levels of economic activity in the United States and abroad; and uncertainties in the financial markets.

Perspective of participants on continued ANGTS support

The ANGTS participants have spent the past 5 years on the design and engineering of the Alaskan pipeline segment and the gas conditioning plant on the North Slope. They have also been working with a consortium of major banks to develop the basic structure of a financing plan for the project. Many regulatory approvals have already been granted to the project, including: FERC's conditional certificate of public convenience and necessity [4] and other orders approving financial and design parameters for ANGTS, the Interior Department right-of-way for the pipeline, which covers 500 miles of Federal land in Alaska, EPA air quality permits, EPA and Army Corps of Engineers water quality permits, Office of the Federal Inspector [5] approval of the gas conditioning plant design, and Federal land use permits for

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[4]A certificate of public convenience and necessity is a permit issued by FERC which authorizes a utility or regulated company to engage in business, construct facilities, provide some service, or abandon service.

[5]The Office of the Federal Inspector for ANGTS was established by Reorganization Plan No. 1 in 1979. This office serves as the enforcement agency for all Federal authority on matters pertaining to the system's preconstruction, construction, and initial operation.

construction camps and airfields. Many other permit applications are pending, and Northwest officials anticipate approval and completion of key pipeline design, engineering, and planning work in 1983.

ANGTS sponsors and the North Slope producers told us that they all remain committed, in varying degrees, to the project. Several participants have explored alternative delivery systems and said they will continue to examine the competitiveness of other projects. Some participants fear that ANGTS will be continually delayed. Northwest, on the other hand, believes a recurrence of gas shortages could quickly alter these members' perceptions.

The most frequent concern expressed was the level of continued expenditures for ANGTS. As long as minimum spending can be continued, project expenditures are not seen as a major problem, according to participants. The gas pipeline sponsors would look to Canada, lower 48 State supplies, and offshore gas to substitute for Alaskan gas if the pipeline is not completed. Northwest, however, does not believe such supplies will be sufficient and has taken the position that all of these sources, as well as Alaskan gas, will be needed to meet U.S. demand.

INCREASED PROJECT COSTS AND RESULTING MARKET PROBLEMS FOR ANGTS

The construction cost estimates for the ANGTS project have steadily risen since 1975. Between 1975 and 1982, the estimated cost of the entire project (in 1982 dollars) increased 72 percent. A 1981 House Committee report [6] gave the following explanations for these increases: (1) the project's delay, (2) the inclusion of the gas conditioning plant (approximately $4.3 billion) in the ANGTS system through the 1981 congressional waiver package, and (3) increasing interest rates. The President's decision estimated that construction for just the pipeline segments would cost $14.4 billion. [7] Our data indicate that the estimated construction cost for the entire project is now $24.8 billion, as shown in table 1. (This cost estimate reflects the 2-year delay in the project announced by the consortium in April 1982 and the FERC-approved cost estimate of

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[6] House Committee on Energy and Commerce, "Waivers for Alaska Gas Pipeline," House Rep. No. 350, Part 2, 97th Cong., 1st Sess., Dec. 3, 1981.

[7] All costs in this report are in late 1982 dollars unless otherwise noted.

February 1983.) Northwest believes that increases in the project's costs are primarily attributable to inflation during the project's delay.

Gas marketability in doubt due to high price for ANGTS gas

The high costs of the ANGTS project lead to a delivered gas price that is too expensive for U.S. gas consumers through the 1980's. Over the life of the project, however, ANGTS prices could become more acceptable to consumers. The marketability problems of Alaskan gas in the lower 48 States have, in turn, adversely affected the financing and completion of the ANGTS project.

Past estimates of the delivered price of ANGTS gas in the early years of the project have ranged between $10 to $12 per thousand cubic feet (mcf) in 1982 dollars.[8] This price would be considerably above the projected price of $3.89 for lower 48 States natural gas in 1990.[9] At the same time, however, average delivered prices for ANGTS gas over 20 years were projected to be about $5.56 per mcf in 1982 dollars. Northwest, however, has advised us that the $10-$12 cited above would be significantly lower if it were recalculated on the basis of the February 1983 FERC-approved cost estimate, and if the anticipated results of Northwest's ongoing cost optimization work (see ch. 3) are realized.

Using a minimum charge analysis (see app. VIII), we calculated the fixed and annual expenses that ANGTS must recover and that are not economically avoidable. We have estimated an initial transportation charge for ANGTS gas of $5.25 per mcf. When a maximum wellhead price of $2.28 is added to this transportation charge, a delivered price of $7.53 per mcf results. (This cost excludes any taxes). This price is still higher than projected, average lower 48 States prices. (See p. 18.)

The project sponsors have been exploring possible measures for reducing the price of ANGTS gas in the early years of the project in order to make the gas competitive with lower 48 State supplies and alternative fuels. (See p. 34.)

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[8]House Committee on Energy and Commerce, "Waivers for Alaska Gas Pipeline," House Rept. No. 350, Part 2, 97th Cong., 1st Sess., Dec. 3, 1981.

[9]See U.S. General Accounting Office, "An Analysis of Natural Gas Pricing Policy Alternatives," GAO/RCED-83-13, Feb. 3, 1983.

Table 1

Current Estimated Capital Costs of ANGTS

	Construction costs in 1982 dollars		
	Base estimates	With contingencies	Capital costs in current year dollars with interest (note a)
	------------------(billions)------------------		
Alaska pipeline	$ 8.6	b/$9.9	$ 17.2
Gas conditioning plant	3.4	c/ 4.1	7.0
Canadian pipeline	5.9	c/ 7.4	12.1
Lower 48 States pipeline	3.4	3.4	4.6
Total	$21.3	$24.8	$40.9

a/Compiled by GAO, using interest and inflation rates found in appendix III. Estimates were factored from construction cost with contingencies.

b/Assumes FERC-approved, 12-percent contingency to cover normal uncertainties associated with estimating costs of materials, labor, equipment, etc., and unexpected or unlikely uncertainties such as earthquakes, sabotage, etc.

c/Assumes sponsors' 20-percent contingency.

Source for 1982 estimates: Participant companies. Alaska pipeline costs taken from FERC cost certification order of Feb. 18, 1983, plus some costs deferred.

The current upheaval in international oil markets is a key factor impacting the economic viability of the ANGTS project. It had always been assumed that the North Slope gas would be priced higher than competing gas supplies in the first years of the project. However, the combination of inflation and rising oil prices would, within a few years, cause the prices to crossover, making ANGTS gas cheaper than oil. Without the prospect of rising oil prices, however, the project's economics are in jeopardy, and will require novel tariff approaches and specially tailored financial packages.

Two issues surrounding the high price of North Slope gas directly affect its marketability in the lower 48 States:

(1) A roll-in cushion that is too small to absorb the high price of Alaskan gas.

(2) State public utility commissions' reluctance to accept ANGTS gas because of its relatively high price.

Roll-in cushion for Alaskan gas

ANGTS was expected to benefit from the presence of old gas at regulated prices with which ANGTS gas would be averaged, or rolled-in.[10] The Congress expected this to cushion the impact of costly Prudhoe Bay gas on consumers. Whereas some old gas may be available in 1983 as originally anticipated, the new ANGTS schedule of a 1989 completion would bring Alaskan gas to market after deregulation (in 1985), at a time when little cheap gas will be available to subsidize ANGTS and make its gas competitive in the early years of the pipeline's operation. (We recognize that the administration has proposed deregulating all gas, including Prudhoe Bay gas, in 1986.) For example, Data Resources, Inc., projects that by 1990, only 6 percent of U.S. supplies will consist of old gas at regulated prices.[11] Other high-priced gas projects will be using the same old gas cushion to absorb the cost of their gas. One of our recent reports found that by 1990, average lower 48 wellhead gas prices could approach $3.89 per mcf as compared with $2.70 per mcf in 1983 (both in 1982 dollars). Resulting average prices to consumers would be about $4.77 per mcf in 1983 and $5.88 per mcf in

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[10]NGPA, Section 208.

[11]DRI, "Special Study: An Assessment of the Natural Gas Policy Act and Alternative Paths to Decontrol," February 1982.

1990. [12] Northwest believes that the roll-in cushion is not a prerequisite for marketing the gas and has not been a key consideration in the sponsors' marketing plan.

State public utility commissions' reluctance to accept Alaskan gas

Recently, three State public utility commissions--California, Colorado, and Iowa--have expressed a reluctance to see Prudhoe Bay gas delivered to their consumers, should its price be considerably above other domestic supply sources. Based on a continued outlook of increasing natural gas prices, other States could adopt a similar attitude toward ANGTS gas and exert pressure on distribution companies to take gas from other sources. This likelihood depends on gas supply and demand conditions in individual States, particularly during the first years in which Alaskan natural gas is to be delivered at high prices to the lower 48 States. According to Northwest officials, however, a consensus of legal opinion states that utility commissions do not have the power to actually deny a FERC-approved tariff for interstate gas movements.

Most Canadian and U.S. banking officials we spoke with were concerned about FERC's ability to pass through the full costs of ANGTS gas to consumers. They perceived that public utility commissions will have difficulty approving ANGTS gas prices and that consumers may not be willing to accept such expensive supplies. Until there are perceived shortages of gas in the lower 48 States and a need for Alaskan gas, lenders are being asked to finance ANGTS for a future generation. According to these bankers, future consumers may be in no better position to bear the costs of the gas. Our review indicates that the project sponsors will be undertaking gas marketing studies to assess these issues.

FINANCING DIFFICULTIES FACING THE ANGTS PROJECT

In light of the uncertainties surrounding the marketability of ANGTS gas, developing a viable plan for privately financing the project has presented several problems for project participants. The major concerns seen by the financial community for financing ANGTS are (1) the adequacy of credit support and completion guarantees during construction and (2) the availability of private capital in terms of the amount and average

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[12] Conversion from mmbtu to mcf assumes approximately 1,000 btus per cubic foot of gas. See "An Analysis of Natural Gas Pricing Policy Alternatives," GAO/RCED-83-13, Feb. 3, 1983.

life of the financing for such a large project. These concerns largely reflect current gas market problems. It is unclear to what extent improved markets would moderate or affect these financing difficulties.

Adequacy of credit support and construction completion guarantees

Members of the financial community with whom we spoke expressed concerns about the adequacy of credit or collateral for securing the large amounts of funds which must be borrowed to finance ANGTS' construction. The banks are also concerned about the lack of adequate guarantees to assure that the project will be completed once construction begins. These concerns go to the heart of the financial issues facing ANGTS. Moreover, unless the project's participants can assure potential lenders that they can repay the project's debt (both principal and interest), sufficient funds will not be forthcoming to privately finance the system.

In 1981, a group of commercial bankers advising the ANGTS sponsors prepared a report outlining financial issues and problems facing the financing of the Alaskan facilities. [13] Their report stated that the credit capacity of the existing pipeline company group is insufficient to attract the necessary funds to complete the project. The report concluded that the ANGTS project cannot be viewed as an acceptable financial risk until it is proven economically feasible and the debt is supported by repayment assurances on the part of the sponsors, producers, and other beneficiaries. ANGTS sponsors do not feel that current economic conditions are favorable for attracting new members, who could bring additional financial backing to the project, so no effort has been made to increase participants at this time. (Our analysis of the effectiveness of increasing participants is discussed in ch. 3, see p. 40.)

The ANGTS participants have pledged various amounts of equity and debt support to the project. The producers have agreed to support 30 percent of the costs of the Alaskan facilities ($7.3 billion, using our estimates). The banks have approved the sponsors' pledge of $8 billion in equity and debt support. In addition, the banks have suggested that a pool of funds ($3 billion to $4 billion) may be available to cover part of the project's cost on a limited-security basis. Our analysis indicated that these preliminary financial committments would

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[13] See "Alaska Natural Gas Transportation System (Part 1), 1981: Joint Hearings on H.J. Res. 341 before the Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce and the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs," 97th Cong., 1st Sess. 563-608.

provide support for about 80 percent of the estimated $24.2 billion of construction and interest costs [14] of the Alaskan facilities (current year dollars). Thus, the Alaskan facilities could need an additional $5 billion in credit support before money is made available to the project.

Estimated world capital available for ANGTS is uncertain

The bankers' 1981 analysis also states that "the maximum amount of Project credit available for the Alaskan segment of ANGTS is estimated to be between $12 billion and $18 billion." The results of this capital availability study are based on certain assumptions and underlying conditions, many of which were optimistic or have changed since 1981, when the study was prepared.

The $12-billion to $18-billion estimate is a maximum figure under the assumption that the ANGTS loans would be perceived as being the equivalent risk of debt with a medium-grade (A/Baa) credit rating. (The banks felt this was the minimum rating acceptable to attract capital for this size project.) The estimates also assume that the top 100 U.S. commercial banks will lend 80 percent of their legal lending limits [15] to the project and that institutional lenders will contribute $1.5 billion to $2.5 billion. Moreover, the $18-billion figure includes foreign capital from Mexico (currently undergoing its own financial problems) and from Canada which, based on our discussions, is unlikely to be lent outside of Canada.

Some of these 100 major U.S. banks would probably not be willing to dedicate such a large percentage of their loans to the ANGTS project. These banks would have to limit some lending during the project's construction period to make 80 percent of their legal lending limits available to ANGTS. Moreover, our discussions with institutional lenders indicate a decided unwillingness to participate in the ANGTS project because of its

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[14]The interest on the debt portion of the funds used during construction of ANGTS is approximately $4 billion, using our inflation assumptions.

[15]At the time of the bank's study, U.S. banks were only allowed to lend 10 percent of their capital to any one project. When adjusted for new 15-percent legal lending limits for U.S. banks, as a result of the 1982 Depository Institutions Act, this range could be about $13.9 billion to $19.6 billion.

perceived risks. Internal lending limits [16] on the part of insurance companies, the primary institutional lenders, will prevent them from lending at the levels the bank advisors assumed, on the basis of past major energy projects such as TAPS. Finally, as discussed later in this chapter, Canadian banks are unlikely to be able to lend to both the Canadian and Alaskan segments of ANGTS, thereby reducing the amount of foreign capital available to the project.

Another consideration for the type of capital likely to be available to the project is that current terms of lending are much shorter than ANGTS' life time. Bankers are likely to want their debt amortized over 10 years (7 to 8 years average life), and some international banks will require even quicker paybacks (5 to 7 years). Long-term loans have not generally been available from lending institutions in recent years. The trend towards shorter maturities and average lives is expected to continue. ANGTS has a 25-year lifespan and will require that banks arrange some long-term debt (which is standard practice for large utility construction projects.) This means that ANGTS must be able to attract additional lenders (especially insurance companies, pension funds, other long-term lenders, or the public markets), once it is operating, to refinance its loans. Some investors will seek assurances that these additional funds will be made available to ANGTS prior to any funding for construction.

Since the banks' capital availability study was completed in 1981, world capital market conditions have become less favorable, particularly for large energy projects, according to financial experts. Given declining oil prices, financial markets do not view large energy projects as favorably as other investments.

THE CANADIAN SEGMENT OF ANGTS FACES FINANCING UNCERTAINTY

The 1977 Canada--United States Agreement on Principles Applicable to a Northern Natural Gas Pipeline made private financing an important condition of construction. Financing for the Canadian segment was to follow routinely after the Alaskan segment's financing was in place. This may no longer be the case.

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[16] Maximum amount of funds as a percentage of total company equity that can be lent to any one party as a matter of company policy. Recently, the insurance industry has stressed intermediate-term investments and diversified portfolios to guard against volatile market rates.

Increasing Canadian pipeline costs, interlending problems between the U.S. and Canadian financial community, and conservatism expressed by Canadian lenders have contributed to an uncertain financing outlook for the Canadian segment.

Canadian segment costs exceed domestic financing capabilities

The initial ANGTS capital costs for construction of the Canadian segment were estimated at $4.4 billion. Delays in ANGTS construction and continued inflation in Canada have served to increase these costs to an estimated $7.4 billion ($12.1 billion in current-year dollars with interest). Given the size of Canada's capital market, raising these funds will require the participation of all major Canadian banks as well as banks outside Canada.

During the waiver package hearings, the Canadian sponsors stated that "loan commitments from a syndication of Canadian and foreign banks" would be required to finance their debt share of the project. Foothills Pipe Line Company officials, the Canadian line's operator, told us that Foothills never indicated it would be able to finance the Canadian segment exclusively within Canada. Of the five international Canadian banks advising the project, an official of the Canadian lead bank estimates that, even with good participation from all sectors of the Canadian financial community, only $4.5 billion, or 52 percent of the needed funding, would be available in Canada.[17] Yet, the sponsors and Canadian Government representatives continue to maintain that the way will be paved for the Canadian segment once the Alaskan segment is financed.

Prior to financing the Canadian segment, Canadian banks will require many of the same assurances that U.S. lenders are requesting for the Alaskan segment. Specifically, Canadian banks are looking for completion of construction guarantees, firm price contracts, and perfect regulatory tracking to pass costs through to consumers. Canadian officials we spoke with believe that additional companies would need to participate in the Canadian segment because the Canadian sponsors' assets will not sufficiently guarantee construction. In the view of these lenders, some form of U.S. Government financial participation is likely to be needed to minimize concern over the risk of ANGTS as a whole. However, these bankers do not believe the Canadian Government would be willing to participate in financing.

[17]Based on a 1982 dollar cost of $8.6 billion including interest on funds used during construction.

Considering ANGTS as one project will limit Canadian bank participation

Although ANGTS is often discussed in terms of its parts--the Alaskan segment, conditioning plant, Canadian segment, and Eastern and Western Legs--it is essentially one system for transporting natural gas. As one project, the ability of lenders in the United States or Canada to participate in financing more than one segment will be limited.

Canadian banks are unlikely to be able to participate in financing both the Canadian and Alaskan segment of ANGTS. While Canadian banks are not subject to a legal lending limit, individual bank policies will dictate how much money can be lent (generally 15 to 25 percent of a bank's equity) to one group or project. By lending to their limit for construction of the Canadian segment, banks would be unable to lend to the Northwest consortium even though different companies are involved. On the other hand, if Canadian banks were pressed to participate in financing the Alaskan segment, they would have less money available for the Canadian segment.

If the segments had separate guarantors and credit support, some banks' management could possibly justify loans to more than one segment, according to these bankers. Only one of the major Canadian banks we spoke with said it could participate in financing both pipeline segments by using its international assets.

Previous analyses of the capital available to ANGTS have minimized the problem of inter-project lending. For example, the funding summary presented by the U.S. bank advisors to ANGTS estimates a possible $2.5 billion to $3 billion available to the Alaskan segment from Canada's commercial banks. This figure represents the total internal lending limits of Canadian banks--a figure unlikely to be pledged to Alaska. The waiver package report states that

> "The participation of the Canadian banks in the Alaska segment of the ANGTS system will depend to a great extent on their required commitment to the Foothills project * * * and the extent to which non-Canadian banks are able to differentiate the Foothills and Alaska risks for legal and house lending limit purposes."

U.S. and foreign banks, therefore, face the same difficulty in providing capital for either segment as Canadian banks do.

ISSUES SURROUNDING U.S./CANADIAN RELATIONS AND ANGTS

The 1977 agreement between the United States and Canada contains many provisions which need to be revised because of delays in ANGTS' construction, according to Canadian Government officials. For example, they believe that the construction dates of the agreement require changes since it states that the project's construction would begin on January 1, 1980, and be completed by January 1, 1983. The agreement also includes outdated gas costs and tax provisions which may need to be restudied in light of increased costs for the project, according to these officials. Representatives of the Canadian National Energy Board and the Northern Pipeline Agency believe these changes would not alter the fundamental nature of the agreement and would not be renegotiated until both Governments are sure ANGTS will proceed.

Officials of the Canadian Government told us that the United States Government cannot take Canadian support for ANGTS for granted. Canada will not always support a land bridge pipeline to the United States. Instead, the Canadians would probably pursue ideas to develop their own arctic gas without U.S. assistance, according to these officials. Moreover, if the ANGTS project is postponed indefinitely, they doubt it could be revived because Canada would not take the political chances of backing the U.S. project again. Northwest believes, on the other hand, that ANGTS is quite beneficial to the Canadian economy and that the political problems described by these officials could be overcome quickly when the project is needed. Northwest also points out that the substantial Canadian investment to date would also be a factor for the Government to consider.

INVESTMENT/COSTS OF ANGTS TO DATE AND POSSIBLE ATTEMPTS TO RECOVER THESE COSTS

A major benefit of ANGTS is that over 4 years of study, design, and engineering work have been invested in the project. Any system to utilize the Prudhoe Bay gas could benefit from this engineering work on the arctic environment.

Cost estimates for ANGTS have been scrutinized by the Office of Federal Inspector and FERC to approve the reasonableness of their estimates. The pre-build sections of the project in Canada and the United States have been completed and are operational. (This system anticipates recovering its expenditures through already approved tariffs.)

The participants' investment in the Alaskan segment of ANGTS has included design engineering and cost estimation work for the pipeline and the gas conditioning plant. In Canada, an additional $250 million has been spent on design and preliminary study work for the remaining Canadian segment. (See table 2.)

In addition to private investment, ANGTS has involved sizable Federal expenditures for regulatory oversight and processing of the project's permits. We have identified major outlays on the part of three Federal agencies. (See table 3.) However, additional money has been spent by agencies such as the Department of State, the Department of Transportation, and EPA for intermittent monitoring and permitting.

The State of Alaska also established a focal point--the State Pipeline Coordinator's Office--to coordinate permitting requirements for ANGTS within the State. The Office was designed to avoid the coordination problems encountered during the construction of TAPS. Staff from a variety of State agencies have been detailed to this Office for the past 4 years at a cost of over $6.8 million. Northwest has reimbursed these costs under the provisions of a 1978 State agreement.

Table 2

Investment in ANGTS by Member Companies
(December 1982)

Component	Cost (millions)
Alaskan segment	a/ $ 750
Canadian segment	a/ 250
Pre-build	2,345
Total	$3,345

a/This figure includes costs incurred since 1970 (including some allowance for funds used during construction), during the preliminary study and route selection process carried on the books of sponsors. It also includes some reimbursement for expenditures of Federal and State government agencies.

Table 3

Costs to U.S. Government for ANGTS
Oversight Since 1977 Presidential Decision
(December 1982)

Agency	Cost (millions)
FERC	$ 7.3
Office of Federal Inspector for ANGTS	a/ 40.4
Interior Department	b/ 5.4
Total	$ 53.1

a/Northwest has reimbursed $3 million of this total in accordance with Federal regulations (10 C.F.R. 1530). An additional $4.7 million has been appropriated to the Office of Federal Inspector for FY 1983 expenditures.

b/This sum has been billed to the Northwest partnership under the reimbursement provisions of the Mineral Leasing Act of 1920, Section 28(1), as amended.

Efforts to recover ANGTS investment could occur if the project fails

In the event ANGTS does not go forward, the participants are likely to seek recovery for their expenditures on both the Alaskan and unbuilt Canadian segments of the project. Expenditures might be attempted to be recovered in four ways: (1) depreciating the investment over time in the normal course of business as an asset with future value, (2) FERC's allowing these sunk costs to be recovered in lower 48 States' pipeline system's rate base, (3) absorbing the investment as a loss for tax purposes, and (4) selling the project's engineering and technical data.

Some costs for the ANGTS project have already been approved for inclusion in the sponsors' rate base. [18] The producers generally would look to the sponsors for a cost recovery plan and would hope to be able to share equally in any returns. Since the producers do not operate pipeline systems, however, they would not be able to recover expenditures directly through pipeline rates. Most participants are not optimistic about the likelihood of recovering all of their investment. Insofar as FERC permits recovery of any ANGTS investment, gas consumers would bear the burden of this recovery.

The gas pipeline companies are more likely to seek a rate base pass-through for their investment or sue for cost recovery. [19] However, provisions of the 1981 congressional waiver (P.L. 97-93) only allow billing of ANGTS consumers once FERC has certified the date by which the system is anticipated to be operating. It is unclear whether the law would allow cost recovery if no certification has been made.

Several of the project's members believe that there would be no recourse to recover their sunk costs except through future tax write-offs. To this extent, as with a write-off by any business entity, the U.S. taxpayers would bear roughly half of any investment written-off.

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[18] FERC, "Order Approving in Part and Disallowing in Part Expenditures Claimed for Inclusion in Rate Base," June 1, 1982.

[19] For example, the unsuccessful applicants for the pipeline route, Arctic Gas and El Paso, have brought actions in the Court of Claims to recover some of their costs either from their FERC rate base or the U.S. Government. (See El Paso Alaska, et al. v. U.S., Court of Claims, 704-81C (filed Dec. 7, 1981), and Alaskan Arctic Gas Pipeline Co. v. U.S., Court of Claims, 214-80C (filed May 6, 1980).

A more complicated situation arises if another project attempts to move forward to use North Slope gas if ANGTS fails. The Northwest partnership has already taken steps to copyright some design data to prevent competitors from using it (without compensation). Legal opinions for the State of Alaska have anticipated that protracted litigation over interpretations of ANGTA would occur if another project attempted to obtain Federal certification, either new or transferred from Northwest. A Northwest official agreed that the partnership would likely decide to stop an alternative project if it was thought to be detrimental to the national interest. Otherwise, an effort would be made to sell engineering and technical data to the alternative's sponsors. The State's opinions recommend that new legislation be enacted to limit judicial review and expedite implementation of an alternative if ANGTS does not proceed.

CHAPTER 3

OUTLOOK FOR THE ALASKA

NATURAL GAS TRANSPORTATION SYSTEM

Most experts see the marketing and financial problems of the ANGTS project as an issue of timing. Consumers may not be willing to pay for ANGTS gas in 1989, but by the mid 1990's, its price and supply could become very attractive. Our analysis of the California gas market indicates that ANGTS gas may not be needed in the initial years of the project. The California sponsors are committed to purchase 22 percent of ANGTS gas, but if this demand does not develop, alternative markets will have to absorb additional supplies of ANGTS gas.

Once a market for the gas is secured, obtaining sufficient capital to finance the ANGTS project remains a challenge to ANGTS participants. The complexity of the project will require a combination of special measures to improve its financibility. In examining a variety of options to restructure or expedite the ANGTS project, we found that these project changes, while offering the potential to reduce the project's costs, are unlikely to completely resolve its financial uncertainties. Several of these options may warrant further consideration. Neither the scope or timeframe for our analysis allowed us to investigate their effects in depth.

GAS MARKETS WILL REMAIN MAJOR PROBLEMS FOR ANGTS

The 1977 Presidential decision on ANGTS predicted that by 1990 "* * * even under the most optimistic conservation and production assumptions, natural gas shortages are a very real possibility." ANGTS was viewed as a way to avoid natural gas curtailments because it would deliver "reasonably priced natural gas." Neither of these conditions currently applies to the U.S. natural gas situation or ANGTS gas prices. Consequently, ANGTS has faced major marketing problems. Moreover, one recent industry study does not expect ANGTS to be built by 1995 because of gas marketability problems resulting from a continued gas glut through the 1980's. [1]

The changes that have occurred in the Canadian gas export market illustrate the marketing problem for North Slope gas. In 1982, only slightly more than half of the 1.4 Tcf of Canadian gas approved for export to the United States was actually sold. U.S. gas pipeline and distribution companies contracted to take

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[1]Petroleum Industry Research Associates, "The U.S. Natural Gas Market to 1995: The Impact of Decontrol on Competition Between Gas, Oil, and Coal," Nov. 1982.

Canadian gas have found that its price, $4.94 per mcf, is higher than what their customers are willing to pay. As a result, in April 1983, the Canadian Government announced an 11-percent reduction in the price of gas exported to the United States to maintain its U.S. market share. If Canadian gas producers can only sell half of their gas available for export, it is difficult to see how North Slope gas can compete at higher prices without a change in U.S. domestic gas markets.

Because of these high export prices, Canadian producers are now more anxious to sell their gas. Rising oil and gas prices spurred an increase in natural gas discoveries in Canada. As a consequence, Canada's National Energy Board has just increased allowed exports to the United States through 1993. Under the previous export authorization, Canada's gas exports were expected to decline substantially after 1986 to only about one-third the present 1989 authorized level. The January 1983 Canadian decision has made a total of about 2 Tcf of gas available for export in 1989 and 1990, when ANGTS is scheduled to bring North Slope gas to the lower 48 States. This gas supply is more than twice that planned for ANGTS. Moreover, Canadian gas exports could be priced more competitively than ANGTS since their production and transmission costs will be less than that of North Slope gas. Northwest emphasizes, however, that ANGTS will provide a long-term gas supply which cannot be expected from Canada because Canada will only export gas that is surplus to Canadian requirements.

Another clear indication of the degree to which future gas markets are in flux comes from the gas marketing consultants to the Northwest partnership. During the waiver hearings in November 1981, these consultants concluded that, while natural gas demand in the United States was expected to be flat or slightly declining (except for industrial demand), natural gas supplies from traditional sources in the lower 48 would also be declining. As a result, the gas industry would be turning to supplementary sources of supply, such as imports and ANGTS. This analysis further projected that a long-term rise in real oil prices would make prices for ANGTS gas more favorable. [2] These same analysts now believe that slow economic recovery and sluggish industrial demand have altered their expectations for markets for high-priced energy projects. In addition, changes in oil prices which would have made gas more competitive have not occurred.

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[2] "Alaska Natural Gas Transportation System (Part 2), 1981: Joint Hearings on H.J. Res. 341 Before the Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce and the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs," 97th Cong., 1st Sess. (1981) (Statement of James T. Jensen, President, Jensen Associates).

Regional gas markets may cause further delays in ANGTS completion

Prior to financing ANGTS, an intensive marketability study will be required by lenders to justify the project's economics. Banks told us they will require that ANGTS pass a stringent market test and will examine gas markets regionally, especially in light of a recent court decision which criticized the Government for not adequately considering regional needs in approving high-priced Algerian LNG imports.[3] ANGTS sponsors have not yet done a regional gas-marketing study for the project.

To identify the types of problems ANGTS gas may have in regional markets, we examined California's natural gas situation. The California sponsors of ANGTS (Pacific Gas and Electric Company and Pacific Lighting Company) have contracted for approximately 22 percent of the North Slope gas. These companies believe they will need this additional gas by the 1990's, but could plan around further delays in ANGTS' schedule. They anticipate that ANGTS gas could exceed their needs in 1989-90, as with any large supply project. As other sources of supply drop off, the excess would be absorbed.

Forecasts of natural gas supply requirements for California differ sharply in their conclusions on the need for Alaskan gas. A report of future gas markets by staff of the California Public Utilities Commission, for example, concludes that neither North Slope gas nor LNG imports are needed by California consumers through 1990.[4]

The California Gas Producers Association also agrees that California has an excess natural gas supply which is "being delivered into an overall declining natural gas market." This group takes issue with utility forecasts which show (1) declining gas supplies from traditional suppliers to California at least through 1990 or (2) steady demand for gas, given new on-line nuclear capacity, which would replace some gas electrical generation. This group believes "* * * the realities of the natural gas supply-demand situation in California dictate that [ANGTS is] pushed further and further into the future."[5]

A forecast reaching entirely different conclusions is the "1982 California Gas Report" prepared by participating

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[3]West Virginia Public Service Commission v. DOE, 681 F. 2d 847 (1982).

[4]California Public Utilities Commission, "Staff Summary Long-Term Forecast of Natural Gas Supply Requirements and Costs," Oct. 8, 1982.

[5]California Gas Producers Association, Bulletin No. 82-31A. Aug. 11, 1982.

California utilities. This report shows that as much as 32 percent of California's gas in 1990 and 47 percent in 1995 must come from supplemental gas sources because of: increased gas demand for industrial cogeneration requirements, a modest increase in residential customers, and uncertainty surrounding future gas reserve additions from domestic U.S. supplies.

Industry often considers California as a premium energy market where utilities must pay a higher price for clean-burning fuels, such as gas, because of the State's air quality requirements. However, some analysts feel the size of this premium is small and would not allow ANGTS gas to be competitive. If North Slope gas is not clearly needed in California (22 percent of its market), finding other markets for this share of the gas will be a major task for the project's sponsors and could affect the current timing of the ANGTS project.

ANALYSIS OF RESTRUCTURING OPTIONS TO EXPEDITE THE ANGTS PROJECT

A variety of measures might be taken to attract more participants and lenders to the ANGTS project or to modify the pipeline itself in hopes of reducing its costs and making the system more financable. We examined a variety of suggestions to change the current ANGTS project to determine what, if anything, has the potential to make the current project more viable. These measures are in some ways interrelated because no single action is likely to resolve the problems outlined in chapter 2. Northwest is also examining a number of other measures, which we have not evaluated, that they believe have the potential to substantially reduce project costs. [6]

Leveling or otherwise changing the project tariff

In light of the marketability problems facing the ANGTS project, the project's sponsors have been exploring measures to enhance the marketability of Alaska natural gas. As mentioned earlier, the marketing problem--i.e., the high price of ANGTS gas relative to domestic supplies--is anticipated to be concentrated in the initial years that gas is delivered to the lower 48 States.

Traditional regulatory and financing techniques for pricing pipeline projects cause this high initial tariff for ANGTS gas.

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[6]These measures include such things as changing the gas-conditioning process and compressing the project's construction schedule.

Under traditional cost-of-service pricing, [7] the time profile of a tariff (schedule of rates approved by FERC for providing gas services) is characterized by high prices in early years and steadily declining prices over time as the project's rate base is depreciated. Over time, therefore, the transportation costs decline in real terms, making average costs for the ANGTS gas more attractive. The difficulty with such a pricing approach comes in financing the system because the initial high prices for the gas make it unmarketable.

An alternative pricing strategy is to price the gas at flat and eventually declining prices or to "levelize" the tariff. (See fig. 2.) This requires that expected returns from the project be deferred in its early years, and recovered in later years when revenue requirements are lower. The prices paid by consumers over time are eventually greater than under a cost-of-service pricing approach, as indicated by the differences in the shaded areas in figure 2. However, differences in the present value of the two price systems are quite small.

Another approach to restructuring the tariff is called indexed financing (or trending the rate base), whereby project revenues are tied to a real rate of return on debt and equity over the life of the project. Each year, the projected average real cost of the gas would be paid by consumers. This would lower front-end costs and initial prices. Rather than declining, however, an indexed tariff would increase over time to reflect inflation. (See fig. 2.)

Levelized tariffs could potentially reduce the price of ANGTS gas in the early years of the project, thus improving the project's competitiveness. According to a 1981 FERC staff study, an indexed financing schedule shows that ANGTS gas delivered at an estimated $21.00 per mcf (1987 dollars) could be reduced to $8.00 per mcf (1987 dollars).

On the other hand, a levelized tariff or indexed financing would require complex negotiations among the project participants and the financial community to determine which costs and returns are to be deferred and by whom. For example, the partnership is exploring (1) reducing the project's depreciation charges, which would require the deferral of equity and possibly principle to creditors, and (2) reducing the gas wellhead price in order to reduce the initial delivered gas costs. Such negotiations are in the early stages, and any outcome will not be known until early next year.

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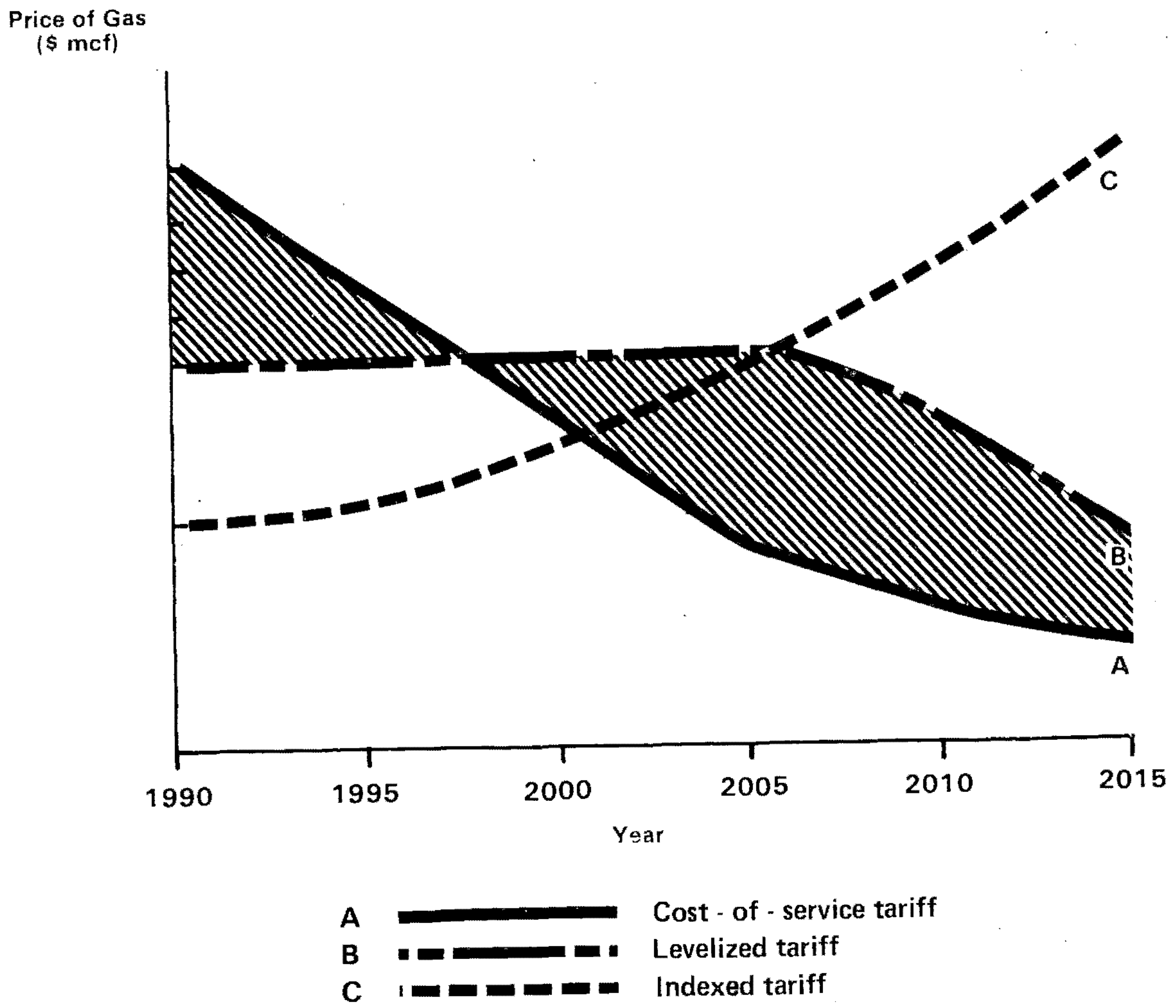
[7] Cost of service is a rate-making concept used for the design and development of rate schedules to ensure that the filed rate schedule recovers only the cost of providing the gas or electric service at issue.

Figure 2

ALTERNATIVE PRICING APPROACHES FOR ANGTS GAS



NOTE: This graph is used for illustrative purposes only. This graph is based on economic theory and past FERC experience. Other price assumptions could be made to illustrate the same point.

Some members of the financial community have expressed concern about using a levelized pricing approach on a project as large as ANGTS. For example, leveling the ANGTS tariff was not attractive to Canadian bankers.[8] The Canadian operating company prefers to see Canadian costs treated in a full cost-of-service tariff even if the Alaska pipeline segment must be levelized to make the gas more marketable. Trended-costs or indexed tariffs were seen as the least attractive proposal because by adding an escalating cost formula to the tariff, a large repayment burden is shifted ahead. If, in an effort to reduce the early price for the Alaskan gas, later prices are high (as under a trended-cost tariff), ANGTS gas may not have a market in the future, according to these lenders.

Changing the regulatory framework for ANGTS

Two aspects of the regulation of ANGTS have been subject to controversy for inflating the project's costs: the incentive rate of return mechanism and wellhead ceiling prices. The effect of these requirements on ANGTS costs is unclear. In addition, some analysts have favored total deregulation of the project in an effort to reduce its costs.

Incentive rate of return

A variable or incentive rate of return (IROR) was required by the President's 1977 decision as a special regulatory mechanism "* * * that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above budgeted cost." Basically, IROR is a ratemaking procedure to award a target rate of return (17.5 percent) to ANGTS investors if the pipeline is built at its estimated costs, a higher rate of return if the project comes in below estimated costs, and a lower rate of return if the project comes in above its estimated costs. This mechanism was believed necessary to avoid a repetition of cost overruns experienced with TAPS and to prevent overruns from being passed on to consumers in the ANGTS project's rate base. FERC's orders finalizing the IROR mechanism were issued in 1979. Proceedings to determine a target cost estimate are still ongoing.

IROR has been criticized for acting as an incentive for the project's participants to overestimate the costs of the project. As described by an early advocate of the mechanism,[9]

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[8]The National Energy Board of Canada and McGill University sponsored a conference in November 1982 on "Regulation of Pipelines in an Inflationary Era," which discussed various methods to levelize pipeline tariffs.

[9]Walter Mead, "The Economic Viability of the Alaska Natural Gas Transportation System," Sept. 15, 1982.

"An intentional overstatement would increase the probability of meeting * * * projected costs." Some analysts believe that the difficulty in financing ANGTS is because the project's costs have been overstated in order to guarantee investors' the highest return under IROR. One suggested that costs may be overstated as much as 20 percent. The Northwest partnership, on the other hand, believes it has put forward a realistic cost estimate in full recognition of the need to obtain financing for the project.

In practice, the effect of IROR on construction costs is uncertain. In addition, it is a complicated and untested regulatory mechanism, and some questions exist as to the Government's ability to enforce it fairly and efficiently. According to one financial analyst we spoke with, if the ANGTS project were economic, investors would probably accept a marketplace rate of return and would not require such a special mechanism.

Wellhead pricing

NGPA sets certain ceiling prices for the purchase of ANGTS gas from the producers. This value, which varies monthly ($2.25 per Mmbtu in December 1982), is added to the transportation costs of the project in calculating the delivered cost of the gas. Several studies [10] have assumed that the producers might accept other than this ceiling price for their gas, particularly for alternative proposals to move the gas from the North Slope.

One way to restructure the pricing of ANGTS gas would be to deregulate the gas wellhead price, which, in effect, would result in "netback" pricing. This would require a change to the Natural Gas Policy Act so that ceilings on the producers' returns could be removed. [11] An unregulated wellhead price would be determined from competition, with competing fuels in the marketplace--primarily gas competition with oil. Once a market price is set, subtraction of the costs of transporting and distributing the gas would leave the producers with a wellhead price. One advantage to a deregulated wellhead price is that the producers might have more incentive to ensure that resources are allocated efficiently and transportation charges (derived from ANGTS construction, operating, and maintenance costs) are minimized if they hope to get some return for their

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[10] See ICF, CRS, and Governor's Economic Committee on North Slope Natural Gas studies, discussed in chapters 4, 5, and 7 respectively.

[11] The administration has proposed legislation to remove all existing controls on natural gas by 1986. See "The Natural Gas Consumer Regulatory Reform Amendments of 1983." (H.R. 1760)

gas. On the other hand, if gas prices were to increase dramatically due to an oil supply disruption, large profits could be transferred to the producers.

Total deregulation

Another alternative takes the idea of deregulating wellhead prices further to a totally deregulated project (first proposed in 1976 by the New York Public Service Commission). Under this concept, the participants would be left to devise arrangements for an Alaskan pipeline to deliver competitively priced gas in the lower 48 States without any Federal regulation. The potential advantage of this concept is that the costs of the project might be reduced if no guarantee of payment from consumers through a tariff was available. (Neither the wellhead or delivered price for the gas would be subject to Federal regulation.) In this way, cost overruns or bad management would directly be the sponsors' responsibility and could affect their returns. However, this approach's disadvantage is that an unregulated project could deliver gas at uncompetitively high prices and leave its sponsors with a "white elephant" project. (Presumably industry would not build a system with such a market outlook.) It is also unclear what Canada's reaction to an unregulated project might be since Canada has emphasized close regulatory tracking to assure costs are passed through as a requirement for financing.

Changing the design of the Alaska segment of the pipeline

In order to improve the economics of the project and reduce the unit costs of the pipeline, experts have suggested that it could be redesigned. The most frequent change mentioned is to increase the pipeline's throughput [12] and pressure. We also discussed adding a small pipeline spur to the system for LNG conversion in South Alaska because of the State's interest to provide LNG for export. [13]

Increasing pipeline throughput and pressure

The 1979 FERC order approving design specifications for the Alaskan pipeline resulted from an examination of a variety of pipeline diameters and pressures. FERC approved a 48-inch-diameter, 1,260-psig system for Alaska as requested by the

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[12] The volume of material, as measured in cubic feet or barrels, that flows through a pipeline during a defined time period (day, year, etc.).

[13] Other suggestions to improve the economics of the project, which we have not examined here, include using existing pipelines in Canada, mechanized welding, and the use of ice roads during construction.

sponsors. During hearings, this position has been supported by Canada, the sponsors, and SOHIO. However, the other North Slope producers, the State of Alaska, and the Department of Transportation argued that the system should be designed to accomodate future growth and that a higher pressure system (higher than 1,260 psig) had transportation cost advantages.

FERC's decision on the issue left open the possibility of increasing the throughput capacity if the sponsors later sought such an increase. FERC based its decision on publicly available gas data which did not support the need for a higher capacity system. FERC also believed that any financing problems and safety and reliability questions would need to be resolved. The burden of providing new information justifying an increase in the capacity of the system was left to the producers.

Although the producers have not yet demonstrated the existence of increased Alaskan gas, ARCO, Exxon, and some member pipeline companies continue to support a higher pressure pipeline. They argue that, given the transportation costs for the current ANGTS design and problems in marketing gas at these costs, every effort must be made to reduce the unit costs for the pipeline. Higher pressure pipelines have been successfully financed with completion of the Northern Border pipeline (the Eastern Leg of ANGTS), an 823-mile, 42-inch, 1,435-psig system. (A consortium of 28 banks agreed to loan over $1 billion to this project once completion has been guaranteed by member companies.) Moreover, construction and operation of the Northern Border line and others [14] have increased U.S. industry's experience with high-pressure systems, thereby reducing some of the safety risks originally attributed to them.

In light of advances in technology since FERC's 1979 decision, we believe the ANGTS pipeline could be dated technology by 1989. High-pressure pipelines are no longer an unproven advance in technology, as Northwest previously stated, although such pipelines have generally been built in easier terrain. Our discussions with the Canadian Government indicate that it would not oppose reopening the issue. Moreover, with continuing delays in the project's schedule, and the availability of pipeline pressure test facilities in North Alberta, a test period would not appear to be the deterrent Northwest originally claimed. Northwest's original objections to the cost of additional testing were based on projected increasing inflation and its impact on the project's costs, but were not derived from actual estimates of the cost of a testing program. Northwest has advised us that it is reexamining this issue, but states that additional study is required to determine

[14] For example, a 2,200-psig North Sea gas gathering line (carrying offshore gas from the well to processing facilities) is under construction.

whether the potential advantages of a more technically efficient system would, in fact, offset additional costs (such as possible alignment changes) that might be incurred.

Adding a pipeline spur for LNG export

In light of efforts by State of Alaska representatives to attract foreign customers for Alaskan gas shipped as LNG (see ch. 4), could ANGTS similarly be modified to bring some gas to South Alaska for LNG export? This would introduce a market for some of the gas in Far East countries and might reduce the volume of gas delivered and corresponding marketing problems in the lower 48 States. This concept has not been addressed in previous studies.

Technically, an LNG spur could be designed for ANGTS to allow the system to branch off at Fairbanks or Delta Junction and move south to Valdez or Cook Inlet, according to engineers we spoke with. In order to prevent leaving unused capacity in the rest of the line, reductions in the size of ANGTS downstream from the LNG spur would have to be made. Both pipeline and equipment would have to be redesigned, according to industry officials. This is not likely to be a major design problem. The ANGTS pre-build already splits into an Eastern and Western Leg, so a divided pipeline has already been designed and put into operation for this system.

A spur would add to the total costs of the system but might allow more incremental or phased construction. For example, if gas surpluses continued to hinder marketing Alaskan gas in the lower 48 States, the LNG spur could be built first, allowing some return prior to completion of the rest of the system. It is unclear, however, whether the price of both the gas and LNG would be marketable since the transportation costs of each leg of the pipeline would have to be borne by small volumes of gas and LNG. This question would require further analysis.

Expanding project participants to increase ANGTS' credit support

If more companies were members of the ANGTS project, more collateral might be made available to support ANGTS debt. Similarly, if the current participants are willing to increase their financial commitment to ANGTS, its credit support would be improved. The banks in the United States and Canada consider Exxon to be the only private party likely to improve the project's ability to be financed because of the size of the company's assets. Finally, if the State of Alaska would guarantee debt or participate in financing ANGTS, credit support for the project would be increased.

Based on our interviews with financial institutions, gas producers, pipeline companies (participants as well as nonparticipants), and the State of Alaska, additional credit support is not likely to be forthcoming in the near future to permit successful private financing of ANGTS. None of the major nonparticipant natural gas pipeline companies we spoke with is interested in joining the ANGTS project at this time. Only a few of the participants themselves would consider increasing their financial share if this is needed to bridge a financing gap. Their contribution would not be sufficient. Exxon will not act as a guarantor for the project. Other industrial gas users, according to the banks, would not be in the financial position to help ANGTS or have the intent to participate in the project during a recession period.

As oil companies develop new arctic gas projects, Northwest believes other logical participants will emerge for the ANGTS project. We believe the development of these resources will be longer term than the current schedule for financing ANGTS. For example, OCS Sale 71, the recent Federal Alaskan sale, is not considered to be a "gassy" sale by industry. Our discussions with the companies which actively bid in this sale indicate that they believe it is premature to talk about shipment of Beaufort Sea gas. Many companies have placed little or no value on the gas resources which might be available offshore, in the absence of an economic transportation system. Moreover, these companies are not interested in joining ANGTS in the foreseeable future. Northwest believes that these attitudes will change quickly when the need for Alaskan gas in the lower 48 States is more widely perceived and its marketability has been assured.

The State of Alaska was advised by an investment banking firm to participate in financing ANGTS. However, the State has not become involved since the project was delayed. Our discussions with the State's Department of Revenue indicate that

--the State would require all other monies to be committed to ANGTS before it participates;

--ANGTS support could require lifting the limits on the State's bond market borrowings and could displace other large, popular capital expenditure projects such as roads and public works projects;

--limited funds are available on an annual basis without specific statutory provisions; and

--the extent to which the State must provide infrastructure for the project is likely to offset direct financial involvement.

One State official's estimate of Alaska's maximum participation in a gas pipeline project, even if these conditions were met, during this period of projected declining oil revenues is about $1 billion.

Using the gas to secure the project's financing

While the participants' credit preliminarily committed to ANGTS has not been sufficient to secure the project's financing, another collateral source is the natural gas itself. Using the gas to guarantee ANGTS would require the issuance of gas-backed bonds. In the past, commodity bonds have been attractive to certain investors. However, the bankers we spoke with felt this was no longer a common investment. Moreover, the gas value in the absence of a transportation system to move it would be questionable. The producers would have to pledge their gas as security in addition to their previous commitments, which is unlikely, according to one lender. The State of Alaska has also looked at pledging its share of the gas to guarantee cost overruns or to serve as security for some aspect of financing. According to the State, authority to do this exists, but the value of the gas in such a proposal remains an issue.

Attracting capital from other potential lenders

After analyzing the availability of funds from private capital market sources (e.g., commercial banks, insurance companies, and other institutional lenders), we examined other potential markets that might help finance the Alaskan segment of the project. The single largest such source is the tax-exempt bond market--about $75 billion was raised in this market during 1982.

States and local governments issue industrial development bonds (IDBs) to fund construction of government capital projects and to provide financing for certain types of private investments in plant and equipment. Under Section 103 of the Internal Revenue Code, the interest income from certain of these obligations is exempt from Federal income taxation. The use of IDBs to provide financing for the ANGTS pipeline and related facilities in Alaska has been considered. However, the Internal Revenue Code's list of acceptable tax-exempt activities does not include pipelines and would preclude issuance of tax-exempt IDBs for use in financing portions of ANGTS (I.R.C. sec 103(b)(4)). The Congress would have to amend the code to allow such financing for the ANGTS system.[15]

There are advantages as well as disadvantages associated with using tax-exempt bonds. Some officials within the State

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[15]The Code defines an IDB as any issued obligation, the proceeds of which are used in any trade or business carried on by a nongovernmental entity. The repayment of principal or interest must be secured by collateral in the form of property.

support IDBs for financing the ANGTS gas conditioning plant, pointing to the lower rates of interest on tax-exempt bonds as a way of shifting the cost of the project and reducing the price of the gas. They also indicate that the tax-exempt debt securities market offers an opportunity to broaden the capital available to finance ANGTS. One disadvantage of IDBs to finance ANGTS is some potential loss of Federal revenues to the Treasury from investors shifting funds from taxable securities to the tax-exempt securities market. However, a University of Chicago study has shown these shifts have minimal impact on markets. Another concern focuses on the adequacy of the credit support for the proposed issuance of IDBs and the ability of the State or municipality to generate adequate property tax revenues in the future to repay the bonds' principal and interest.

Federal financial support to guarantee project completion

The 1977 Presidential decision determined that Prudhoe Bay gas transported through ANGTS was marketable and that ANGTS, therefore, could be privately financed. Under the provisions of ANGTA, any change from private financing would require a waiver of law from these requirements. [16]

In 1977, the Department of the Treasury submitted a report analyzing ANGTS' financing to the President. The report's principal conclusion was that the system could be privately financed without Federal financing assistance. However, the report noted that private financing could be difficult, if not impossible to arrange, without resolution of a number of issues. It states that before any Government funds are authorized, the producers, the State of Alaska, and consumers should all be participants in the system's financing. [17]

The most commonly identified forms of Federal financing assistance or participation for a project such as ANGTS include:

1. Providing a specified amount of funds directly to the project for financing cost overruns.

2. Government guarantee of all or part of the project debt.

3. Financial assistance similar to some programs provided under the Energy Security Act (P.L. 96-294) and

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[16] Legislation has been introduced in the 98th Congress to prohibit any Federal financial assistance to ANGTS. See H.J. Res. 192.

[17] The Treasury report further lists five principles for Federal financial assistance to minimize its impact on the market.

administered by the Federal Synthetic Fuels Corporation. These include: loans, loan guarantees, purchase agreements, and joint ventures.

4. Federal insurance similar to that offered by the Overseas Private Investment Corporation (OPIC) to protect U.S. companies from the political risks involved in investment abroad.

All of these would require special Federal authorizing legislation and appropriation. For example, Federal insurance could be provided through political risk insurance legislation, similar to that established for OPIC, which could create an insurance reserve to pay investors in the event ANGTS' construction stopped for political reasons. Such reasons might include State public utility commissions not passing through ANGTS' costs to consumers, and environmental or Canadian actions. The definition of political risk would have to be defined tightly to avoid mismanagement and unjustified compensation.

Based on our discussions with the financial community, we believe a growing consensus exists (1) that ANGTS is too costly a project to be solely privately financed and (2) its financing is too complex for private financing. A majority of participants feel that Federal assistance will be needed to finance the project. During our interviews with the financial community, Federal loan guarantees were frequently identified as a potential source of assistance. Federal financial assistance would (1) assist ANGTS to assure lenders that debt would be repaid if construction is not completed and (2) open the public debt markets to the project and increase the capital available for financing ANGTS.

On the other hand, Federal financial assistance might further deter some institutional investors looking for high-risk, high-return projects. Some of the other disadvantages of Federal assistance are that:

--The risks of the project's failure would be transferred to taxpayers, many of whom are not gas consumers.

--Lower interest rates would subsidize the market price for the gas.

--The Government would be both the guarantor and regulator of the project, which are potentially conflicting roles.

CHAPTER 4

VIABILITY OF ALTERNATIVE ROUTES

AND MARKETS FOR ALASKAN GAS

Since the 1970's, other proposals have been considered to transport Prudhoe Bay natural gas to market. One such proposal, a gas transmission system operating entirely within the State of Alaska, must overcome marketing, legal, and environmental obstacles before financial support is likely to be forthcoming from potential sponsors.

As with ANGTS, marketing Alaskan natural gas as LNG from an all-Alaskan pipeline system (AAPS) will be difficult, even if sponsors look toward countries in Asia as potential customers. Although Japan, for example, is the world's largest importer of LNG, worldwide competition for a small share of the Japanese market is severe, and an Alaskan LNG project would compete with existing foreign LNG projects that are more developed and have established contractual agreements with Japan.

Legal and environmental obstacles that would confront an AAPS may further preclude its viability as an alternative to ANGTS. The export of natural gas from Alaska's Prudhoe Bay is restricted by law to small quantities. Before large-scale exports to foreign countries are permitted, Presidential action would be required. The environmental ramifications of an AAPS would require a complete analysis, but such a project would confront two potentially significant problems: pipeline burial in areas of considerable earthquake activity and below an Alaskan inlet.

In addition to an all-Alaskan system, other projects that rely on marine systems to transport the natural gas have been advocated. Included among these proposals are (1) the construction of a marine gas pipeline located in the inshore waters of the Beaufort Sea from Prudhoe Bay, Alaska, to the MacKenzie Delta in Canada and (2) the use of icebreaking tankers or nuclear-powered submarines that would transport natural gas directly from a marine terminal at Prudhoe Bay. However, these options, like the all-Alaskan pipeline system, have not been proven economically attractive.

PREVIOUS STUDIES SUPPORTING THE ALL-ALASKAN PIPELINE SYSTEM

An all-Alaskan gas pipeline was first proposed in 1974, when El Paso Alaska Company filed an application before the Federal Power Commission to build an "all-American" pipeline system from Prudhoe Bay to Prince William Sound with subsequent

LNG deliveries to California. El Paso estimated that costs for the entire system, including facilities in California, would total approximately $6.8 billion ($11.1 billion in 1982 dollars).[1]

Support for the El Paso proposal was primarily based on the line's lying entirely within the United States. According to its supporters, this line would result in greater domestic employment, higher tax payments, better security of supply, and regulatory control by one country. (Current proponents of an AAPS believe it could provide the State additional employment opportunities through the development of spur industries such as a petrochemical complex in South Alaska. See ch. 7.)

The President did not select the original El Paso proposal in 1977 for several reasons, including its higher cost of service, the liquefaction plant's location in active seismic areas, and an inability to tap Canadian gas reserves. Nonetheless, the delays surrounding ANGTS have revived consideration of a transmission system solely within Alaska. In addition, supporters of an AAPS view Japan as the logical market for Alaskan natural gas.

In September 1982, for example, ICF, Incorporated, a Washington-based consulting firm, completed its analysis for the U.S. Maritime Administration on alternative methods for transporting Alaskan natural gas to market.[2] ICF concluded that, of the options considered, a trans-Alaska gas transmission system was the most economically attractive option for developing Prudhoe Bay natural gas. Such a system could be constructed for $20.4 billion and deliver LNG to Japan for an estimated cost of $5.90 per million British thermal units (MmBtu).[3] ICF further stated that "* * * if development options were limited to supplying the lower 48 states* * *, then a marine LNG system would be economically competitive with the proposed ANGTS pipeline option." Only the market value of LNG delivered to Japan, however, could cover the estimated costs of the project, according to ICF's analysis.

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[1]"Decision and Report to Congress on the Alaska Natural Gas Transportation System," Sept. 1977.

[2]ICF, Inc., "Alaska Natural Gas Development, An Economic Assessment of Marine Systems," Sept. 1982.

[3]The $5.90 price included a gas extraction cost of $0.52. The NGPA wellhead ceiling price for North Slope gas is considerably higher than this extraction cost. An adjusted ICF estimate, using a $2.28-wellhead price, would result in a delivered cost to Japan of $7.66 per MmBtu in 1982 dollars.

Other estimates of capital costs for AAPS have been derived from industry sources. The National Petroleum Council estimates the capital costs for a land pipeline in Alaska transporting 1 bcfd at about $10 million per mile, or about $8 billion for a pipeline from Prudhoe Bay to Cook Inlet. The liquefaction facilities to process the natural gas at Cook Inlet would require an additional $1.6 billion, for a total of $9.6 billion, according to NPC. Other industry estimates for the costs of a trans-Alaska system range from $19.1 billion to $23.9 billion. These estimates incorporate different assumptions, assume different contingency factors, and are based on conceptual design rather than actual engineering.

ECONOMICS OF ALL-ALASKAN PIPELINE SYSTEM

In order to determine the economic viability of an all-Alaskan pipeline system, we solicited requests for proposals from U.S. engineering firms for an analysis of the engineering costs associated with the construction of an all-Alaskan pipeline system. We selected, as our principal contractor, the firm of Parsons Brinckerhoff Quade and Douglas [4] in association with John J. McMullen Associates, Inc., and the Institute of Gas Technology. Their final report detailed construction cost estimates that include all of the components of an AAPS, namely (1) a Prudhoe Bay gas conditioning facility; (2) a pipeline from the North Slope to Cook Inlet; (3) a liquefaction plant, marine terminal, and tank farm on the Kenai peninsula; and (4) LNG tankers to transport the liquefied natural gas to market. The system would be constructed over 6 years, with a completion date assumed to be the end of 1991.

Cost assumptions for an AAPS

Our contractors developed a base-case estimate for an AAPS, premised on the construction of a conventional pipeline system transporting 2.2 bcfd. The raw gas first would be conditioned on the North Slope to remove impurities, and then transported by pipeline to a liquefaction facility in southern Alaska (see app. IX for pipeline route), where it would be loaded on LNG tankers for transport to Japan. (See fig. 3).

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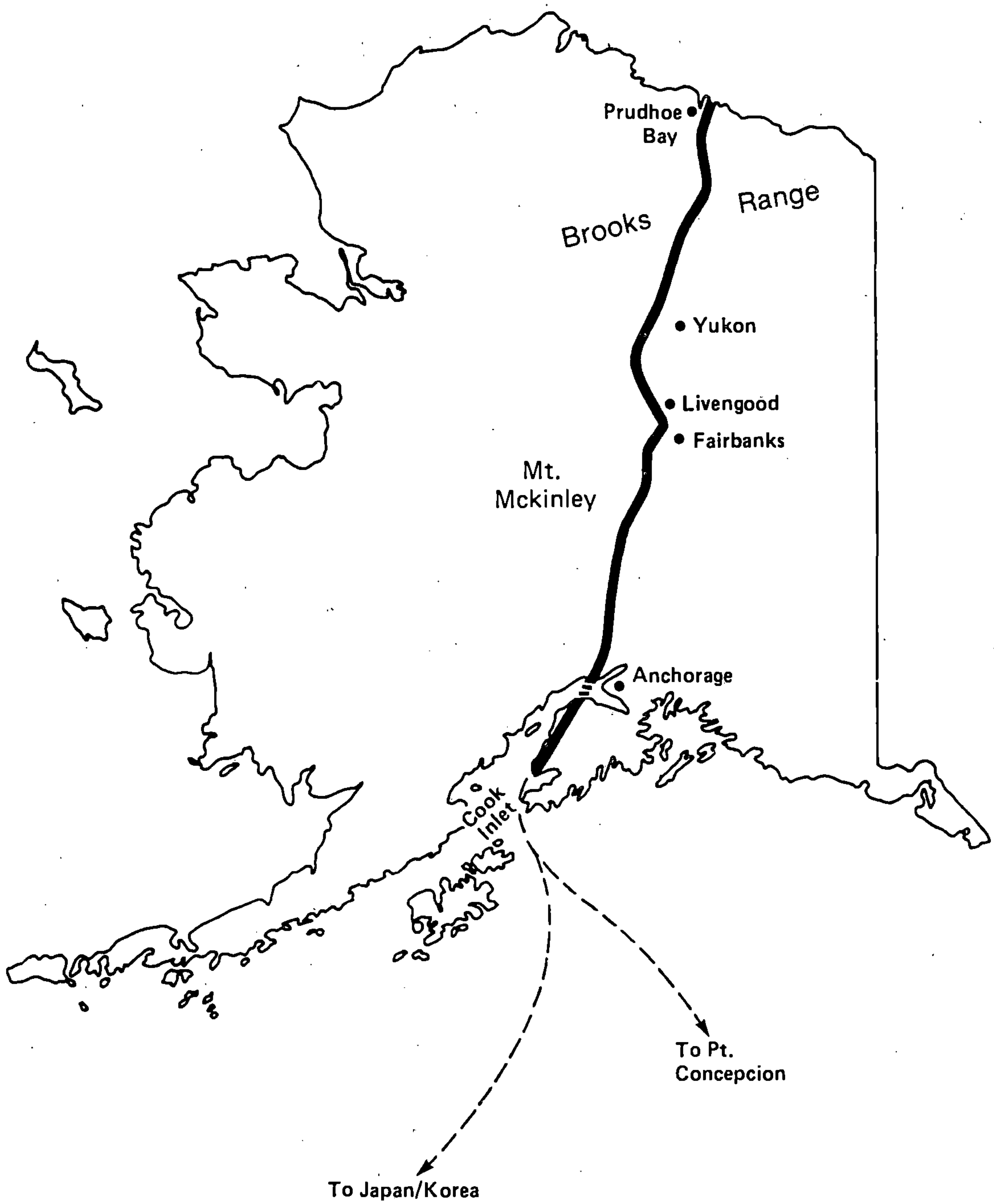
[4]Parsons Brinckerhoff Quade and Douglas is one of the largest engineering, design, planning, and construction management firms in the United States with extensive experience in energy and LNG-related projects.

Figure 3

An All-Alaska Pipeline System



Source: Parsons Brinckerhoff Quade & Douglas, Inc.

Our contractor also evaluated alternatives to the base case by increasing the amount of gas processed, varying the pressure in the pipeline, decreasing the pipe diameter, and locating the gas conditioning plant in southern Alaska. [5]

The contract team included contingency and design factors in its cost estimates for each system component in order to account for the uncertainty in estimations and current industry experience. As displayed below, these factors range from 5 to 40 percent, depending upon the reliability and certainty of each component's estimate. The estimates are most reliable for the marine transportation (which relies heavily on quotations from shipbuilders) and least reliable for the pipeline, where the uncertainties of construction are greater.

	Contingency factor (percent)	Design factor (note a) (percent)
Conditioning plant (North Slope)	20	-
Pipeline (conventional)	25	-
Pipeline (dense phase)	25	15
Liquefaction plant (South Alaska)	15	-
Conditioning plant (South Alaska)	15	-
Marine terminal and storage	10	-
Marine transportation	5	-

a/This factor would account for uncertainties in the design of a relatively new technology.

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[5]Base case: 48-inch-diameter pipe, 1,440 psig, and 2.2 bcfd.

Variant case 1: 48-inch-diameter pipe, 1,260 psig, and 2.2 bcfd.

Variant case 2: 36-inch-diameter pipe, 1,440 psig, and 2.2 bcfd.

Variant case 3: 48-inch-diameter pipe, 1,440 psig, and 4.0 bcfd.

Variant case 4: 36-inch-diameter pipe, 2,145 psig, and 2.2 bcfd.

Gas conditioning facility on the North Slope

The raw gases that are separated from the crude oil at Prudhoe Bay must be conditioned to provide a gas composition suitable for transmission. Carbon dioxide, which has no heating value, must be reduced from about 12 to 13 percent of the raw gas to 1 to 2 percent of the pipeline quality gas. Some natural gas liquids (NGLs)--such as propane, butane, and pentane--must be removed since they could condense in the pipeline and damage compressors. Our contractor assumed that the NGLs would be sold to the operators of the Trans-Alaska Pipeline System at a price of $1.47 per MmBtu and transported with Prudhoe Bay crude oil to Valdez. (The ANGTS sponsors similarly have assumed the sale of NGLs to the TAPS operators.) The revenues accrued from this sale would be deducted from the annual operating and maintenance costs of AAPS.

For the base case, the contractor's estimate for a gas conditioning plant located on the North Slope includes the cost for initial gas compression and chilling. According to our subcontractor, the Institute of Gas Technology, additional compressors will be needed beyond those owned by the producers to act as a contingency should the AAPS line shut down and gas reinjection be needed to maintain the flow of oil through the TAPS line. A North Slope gas conditioning facility is estimated to cost approximately $3.2 billion. (See app. X for discussion of how the system's costs were derived.)

Conditioning the raw gas at South Alaska instead of Prudhoe Bay was evaluated by our contractor as well. The use of a high-pressure gas line, known as dense phase transmission, was considered the only feasible method of transporting unconditioned raw gas across Alaska. The concept of dense phase is discussed on page 55.

Gas pipeline from Prudhoe Bay to Cook Inlet

The conditioned North Slope gas would be transported south via a conventional pipeline system. The pipeline route assumed for our contractor's study generally follows that proposed by the El Paso Company in 1975 to Livengood, near Fairbanks. It then turns south to an area south of Anchorage, where it crosses Cook Inlet and proceeds along the coast of the Kenai peninsula to the base-case terminal at Cape Starichkof. (See fig. 3.)

Our contractor used, as the base case, conventional pipeline technology consisting of a 48-inch-diameter pipe, at a pressure of 1,440 psig and transporting 2.2 bcfd of natural gas. The costs for the pipeline were estimated to be approximately $5.85 billion, or about 45 percent of the total costs for the entire AAPS.

Variations to the base case were analyzed by the contractors, and some economies of scale were determined. For example, the base case is the least expensive for the basic throughput considered (2.2 bcfd). For less gas throughput, a smaller diameter pipeline may be more economical, but such a reduction in the pipeline's size would restrict future increases in gas flow. The contractor also concluded that a system with a larger throughput (4.0 bcfd) would result in economies of scale as well.

<u>LNG plant at Cook Inlet</u>

A liquefaction plant is needed to pretreat and then liquefy the pipeline gas for loading onto specially designed tankers. Pretreatment requires the removal of any components in the gas stream that could lead to corrosion or affect the liquefaction process. For example, the 1 to 2 percent of carbon dioxide remaining in the gas must be reduced even further, and the water in the gas (already reduced at Prudhoe Bay) must be reduced to an insignificant level as well.

Through liquefaction, natural gas becomes a liquid transportable on LNG tankers. (Facilities to regasify the liquid gas were not factored into the contractor's AAPS analysis since the countries assumed to receive the LNG have or will have regasification facilities.) A Cook Inlet liquefaction plant was estimated by our contractor to cost approximately $2.6 billion. (See app. X.) In addition, a storage tank farm and marine terminal would cost about $250 million.

Certain amounts of natural gas would be consumed as the gas is piped to Cook Inlet and converted to a liquid form. Consequently, the initial pipeline throughput of 2.2 bcfd of gas results in a shippable amount of 1.88 bcfd of gas.

<u>Marine transport of LNG</u>

After liquefaction, the resulting LNG will be shipped in refrigerated, pressurized tankers to market, where it will be regasified for distribution. The base case assumes this market to be Japan rather than the U.S. West Coast because of delays in the construction of West Coast regasification facilities.

The shippable LNG volume, 1.88 bcfd of gas, would, according to our contractors, require 12 LNG tankers of 125,000 cubic meters capacity for shipment to Japan. The base case assumes these tankers to be new tankers built and financed in Japan, as Japan has required in recent LNG sales contacts. At $116 million per tanker, the fleet cost would be about $1.4 billion. "Boil-off" of gas during the voyage (used for ship propulsion) reduces this shippable 1.88 bcfd of gas to an estimated delivered volume to Japan of 1.82 bcfd of gas. (Allowance for "boil-off" is incorporated in the calculation of the costs of marine transportation.)

Table 4

Costs for

A Conventional All-Alaskan Pipeline System

Component	Base estimate with contingencies 1982 dollars	Capital costs in current year dollars with interest (note a)
	(billions)	
Pipeline (note b)	$5.85	$11.86
Conditioning facility	3.15	6.38
LNG plant (note c)	2.60	5.27
Marine terminal and tank farm (note d)	.25	.50
LNG ships	1.39	2.82
Total	$13.24	$26.83

a/Calculated by GAO using interest and inflation rates of appendix III.

b/This estimate does not include costs for pipe insulation, socio-economic impacts, highway repairs, geotechnical data acquisition, State ad valorem taxes, and satellite communications system. Such costs have been included in the ANGTS pipeline estimate.

c/Excludes NGL storage facilities.

d/Excludes dock facilities.

Source: Parsons Brinckerhoff Quade & Douglas, Inc., "Report on Engineering Costs Associated with Transporting Alaskan Natural Gas by an All-Alaska Pipeline System," Jan. 1983.

Cost estimates for an AAPS will increase with detailed engineering design

Incorporating the contingency and design factors into each component's estimate, our contractor determined the capital costs for an all-Alaskan pipeline system, as displayed in table 4. As shown, the AAPS could cost approximately $13.2 billion (about $27 billion when the project is assumed completed in late 1991).

Using these capital cost estimates, a delivered price to Japan was calculated by the contractors. The delivered LNG price is estimated at $5.33 per MmBtu, which is the total of three separate prices: a wellhead price of $2.28 per MmBtu, a pipeline system price of $2.50 per MmBtu, and a marine transportation cost of $0.55 per MmBtu. The first component is our late 1982 NGPA ceiling price for Prudhoe Bay natural gas, with the second and third components representing the price needed to recover the fixed capital and annual operating and maintenance expenses of the AAPS.

Using the methodology described in appendix VIII, we calculated a minimum charge, without taxes, based on the construction cost estimates developed by the contractor. A pipeline system price of $2.61 per MmBtu was calculated, which when combined with the wellhead price and marine transportation costs, equates to a minimum LNG price to Japan of $5.44 per MmBtu. Ultimately, the costs of regasification must be added to this charge before the price to consumers can be determined.

The project's cost estimates and the subsequent delivered LNG price to Japan are determined from a conceptual design. These estimates could increase considerably when more detailed engineering design is completed. If, for example, the more detailed pipeline cost estimate for ANGTS, on a per-mile basis, were incorporated into the AAPS estimates, the cost for the pipeline segment alone would nearly double (from $5.85 billion to $10.9 billion). [6] The resulting $18.3-billion Alaskan LNG project would then deliver natural gas to Japan at a higher minimum charge--about $6.49 MmBtu (using the methodology in app. VIII.)

If a market were available for Alaskan LNG in Japan, the gas would have to compete with prices of other current supplies. March 1983 prices for LNG delivered to Japan from southern Alaska, Brunei, Abu Dhabi, and Indonesia range from $4.50 to $5.70 per MmBtu. These prices have varied in recent

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[6] See table 1, page 18. The Alaskan pipeline segment cost for ANGTS of $9.9 billion for 743 miles results in a per-mile cost estimate of $13.3 million. The AAPS from Prudhoe Bay to Cape Starichkof is 823 miles long.

years partly in response to changes in the average price for imported crude oil. Most LNG contracts between suppliers and Japanese utilities peg the price for imported LNG to fluctuations in average crude oil prices.

Dense phase technology could provide less expensive gas

Due to the State of Alaska's interest in another type of pipeline technology, we asked our contractor to consider the option of locating the gas conditioning plant in South Alaska. However, in order to transport the unconditioned gas to South Alaska, a technology known as dense phase transmission would have to be employed.

Dense phase technology relies on a high-pressure transmission line to transport the Prudhoe Bay raw gas to a conditioning/liquefaction facility in South Alaska. [7] This technology has never been employed in arctic conditions, particularly over the rugged terrain and long distance that an AAPS would encounter. Our contractor's analysis shows that dense phase could result in a lower delivered LNG price because (1) the higher pressure allows for the transport of the heavier natural gas liquids that are assumed marketable at Cook Inlet at world prices and (2) lower construction costs result from locating the gas conditioning facility in South Alaska. However, the sale of NGLs may be difficult because of a current world surplus, and the location savings may be offset by higher pipeline costs.

Construction costs in northern Alaska were estimated to be three times those of similar facilities constructed in the lower 48 States and approximately 1.5 times construction costs in southern Alaska. The combined conditioning/LNG plant located at south Alaska, for example, would require about $1.3 billion less than the separate facilities of a conventional system.

However, the capital cost savings due to the plant's southern location may be offset by higher pipeline maintenance costs and the need for additional compressors and fuel. In addition, the amount of saleable gas that can be transported in the pipeline is constrained by the inclusion of large amounts of carbon dioxide, a waste gas. The unconditioned gas also presents a problem for communities along the pipeline corridor that want to use gas for fuel or electrical power generation. The additional costs for conditioning before the gas can serve these local communities must be factored into the total costs for a dense phase system.

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[7]This pipeline has a pressure of 2,145 psig and a pipe diameter of 36 inches.

Since dense phase is a largely unproven technology for such large-diameter, long-distance transmission, our contractors applied a design and contingency factor of 40 percent to the costs for the pipeline. As a result, the pipeline costs for dense phase are higher than costs for conventional technology.

The dense phase system could still deliver gas to market at a price lower than the conventional system if the NGLs can be sold at south Alaska. A potential NGL sale at world prices would reduce the dense phase system's operating and maintenance costs significantly. However, the sale of NGLs at world market prices may be difficult if current market conditions continue through the early 1990's. A surplus of NGLs currently exists in the world market, and most NGL processing plants are operating well below maximum capacity. It is difficult to foresee a viable market for 75,900 to 88,880 barrels of NGLs/day which, at a minimum, would account for about 2.5 percent of the world's 1981 NGL production. [8]

PROBLEMS WITH AN ALL-ALASKAN PIPELINE SYSTEM

An AAPS must overcome marketing, legal, and environmental obstacles before it becomes a viable alternative to ANGTS. As with ANGTS, oversupply of natural gas in the lower 48 States will make the marketing of Alaskan LNG very difficult. California, the logical West Coast delivery point for Alaskan LNG, has a surplus of natural gas that is expected to continue throughout the decade. The transportation of gas from Alaska to California would be subject to FERC regulation. Exports of Alaskan LNG to Asia confront two problems: statutory controls on exports of natural gas and a highly competitive world LNG market. In addition, an AAPS must overcome the environmental consequences of pipeline burial across active earthquake faults and under a major Alaskan inlet.

Marketing Alaskan LNG may be difficult

New LNG deliveries face an uncertain future market in the lower 48 States, as exemplified by recent delays in a West Coast regasification project. The Pacific Rim countries of Japan, South Korea, and Taiwan are envisioned as possible purchasers of Alaskan liquefied natural gas. However, marketing LNG in these countries through 1990 will be difficult since their projected supply gap is small, and several countries with ample natural

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[8]This is a large volume of NGLs. According to our contractor, the average world gas processing plant accounted for 0.08 percent of 1981 production (latest data available).

gas reserves are actively competing to fill the additional supplies still needed. The highly competitive world LNG market will lessen the ability of an all-Alaskan pipeline system to market its resources abroad.

Marketing Alaskan LNG in California will be difficult

The delivery of North Slope natural gas to California, with subsequent distribution to markets throughout the lower 48 States, will be difficult. California is currently experiencing a surplus of natural gas supplies and, according to a report from the State's Public Utilities Commission, does not need LNG through 1990. The recent decision by sponsors of the Point Concepcion regasification facility to postpone the delivery of LNG to California until the 1990's reflects this marketing problem. Moreover, California law (the California LNG Terminal Act) in effect, restricts the importation of LNG into California to LNG from Indonesia and the area of South Alaska.[9] According to staff of the California Public Utilities Commission, natural gas originating on the North Slope of Alaska could not be delivered to California ports until this act is amended.

LNG landing in California would also face the problem of nationwide distribution. In 1974, when El Paso Alaska Company proposed a similar project to market North Slope natural gas in the lower 48 States, it planned to reverse the flow of its Texas to California pipelines so that the gas could flow in an easterly direction to points throughout the lower 48 States. According to FERC officials, the ease with which this pipeline reversal was projected was viewed skeptically by Federal officials.

The problems of nationwide distribution, State statutory restrictions, and gas surpluses in the lower 48 States have led us to discount California and the lower 48 States as logical near-term markets for Alaskan LNG until about 1995. As a result, the contractor's base-case analysis assumed the delivery of Prudhoe Bay gas to markets in Asia, primarily Japan. However, our contractor did examine the shipment of arctic gas to the West Coast as part of a variant analysis and estimated a delivered cost to California of about $5.35 per MmBtu, reflecting a slightly higher tanker transportation charge of $0.57 per MmBtu. (This charge assumes the use of American-built LNG vessels, including the use of existing ships not presently

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[9]We have not analyzed the California LNG Terminal Act to determine whether its restrictions on the geographic origin of the LNG which can be imported into California impose a burden on interstate and foreign commerce.

in operation.) Additional costs for a West Coast regasification facility and a nationwide distribution network would have to be added to the project's cost as well. As a result, the delivered LNG would be priced higher than this estimate.

Japanese supplies of LNG through 1990 appear plentiful

On the basis of information from the Japanese Government, Japanese trading companies, and other forecasting experts, Japan will have sufficient supplies of imported LNG through 1990. Dependent upon the growth rate of the Japanese economy and average crude oil prices, additional supplies of LNG beyond 1990 may be needed. Alaska could supply the additional LNG needs of Japan, but will face severe competition from existing gas exporting countries. It is unclear whether any Japanese market would be available by the time an Alaskan project comes on line.

A Japanese national policy objective is to increase reliance on energy sources other than oil, such as LNG, in order to avoid short-term swings in world oil market conditions. In addition, LNG is viewed as a cleaner and less controversial alternative than either nuclear energy or coal. Japanese consumption of LNG has been projected to rise from a current level of about 0.9 Tcf per year to between 1.8 Tcf and 2.3 Tcf in 1990. The Japanese Ministry of International Trade and Industry (MITI), in its April 1982 forecast on long-term energy demand and supply, emphasized the higher demand estimate of about 2.3 Tcf. Many industry experts believe that the lower demand estimate of 2.0 Tcf will result because Japanese economic growth rates will be lower than those assumed by MITI.[10] In March 1983, for example, the Japanese Institute of Energy Economics (IEE) forecast that LNG demand in Japan in 1990 would be 1.85 Tcf (35.0 million metric tons, (MMT)).

On the basis of information compiled from Japanese trading companies, the existing contracts and commitments that Japanese utilities have with LNG suppliers should provide for yearly imports of about 2.0 Tcf in 1990. If the demand for LNG is 1.85 Tcf, as forecast by IEE, Japan would experience a surplus of 0.14 Tcf in 1990. (See table 5.) On the other hand, a potential shortage of LNG--about 0.365 Tcf--could arise if MITI's higher demand results. The potential shortage would be about 1,000 million-cubic-feet-per day (MMcfd), which could conceivably be supplied by Alaska.

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[10]MITI assumed Gross National Product growth rates of 5 percent annually for 1980-90 and 4 percent for 1990-2000.

Table 5

Supply of LNG to Japan in 1990

In operation	Delivered amount (note a) Million metric tons	Delivered amount (note a) Trillion cubic feet	Contract expiration date
Brunei	5.14	0.272	1992
Abu Dhabi	2.06	.190	1997
Indonesia	7.50	.397	1997
Subtotal	14.70	.778	
New contracts			
Badak, Indonesia	3.20	.169	2003
Irun, Indonesia	3.30	.175	2002
Canada	2.90	.153	2005
Malaysia	6.00	.317	2002
Australia	6.00	.317	2005
Indonesia (supplement)	1.0-1.5	.053-.079	
Subtotal	22.4-22.9	1.184-1.210	
Total supply for 1990	37.1-37.6	1.962-1.988	
Demand estimate	35.0-44.0	1.851-2.327	
Surplus/(Shortage)	2.6-(6.9)	0.137-(.365)	

a/Forecasts of Japanese LNG needs are generally quoted in tons versus cubic feet. The conversion factor used is 52,890 cubic feet of gas per 1 metric ton of LNG.

Source: Compiled from Japanese trading company and Japanese Government forecasts.

However, Alaska would compete with worldwide LNG projects presently under consideration by MITI and Japanese utilities. These projects and their export potential include:

Qatar	0.317 Tcf/year	or	870 MMcfd
USSR	0.159 Tcf/year	or	435 MMcfd
Thailand	0.159 Tcf/year	or	435 MMcfd
Indonesia (Natuna)	0.317-0.423 Tcf/year	or	870-1,160 MMcfd

According to a Japanese trading company, the Government of Qatar has a firm plan to implement the export of 0.317 Tcf of natural gas a year by 1987-88, but no agreements have been reached because of the unclear marketing outlook in Japan. Japan has already invested $200 million in an exploratory drilling program to develop the gas reserves in the Sakhalin Straits of the eastern Soviet Union. Its nearness to Japanese ports and the subsequent lowered transportation costs enhance the viability of the Russian project, but no purchase commitment has been given to the project due to slack Japanese LNG demand.

Based on the discovery of natural gas reserves in offshore Thailand, the Government of Thailand has approved an LNG export plan for surplus natural gas. This project could help offset Japan's trade imbalance ($1.2 billion in 1981) with Thailand. Indonesia also plans to develop its Natuna gas field that could deliver between 0.317 and 0.423 Tcf per year. Japanese utilities have purchased considerable amounts of Indonesian LNG in the past and probably consider Indonesia a very stable source of supply. Indonesia also would have the existing LNG infrastructure to accommodate expanded exports to Japan.

Since the Qatar, Soviet, Thai, and Indonesian projects are further along in their design and development than an Alaskan LNG proposal, competition for a relatively small export market may severely limit Alaskan LNG exports to Japan. For example, if Japanese utilities contract with either Qatar or Indonesia for new supplies, Alaska would no longer have an export market for its natural gas. Also, if contracts due to expire in the 1990's are extended, no supply shortage is likely. The numerous countries that export LNG today or plan to export LNG in the future developed their gas reserves partly in response to an opening Japanese market. As a result, several countries are actively competing for the Japanese LNG market.

<u>Korea and Taiwan have small LNG markets</u>

According to a State Department official and several Asian trading companies, Korea and Taiwan are the only other Asian countries that would likely need LNG in the future. However, opportunities for LNG exports to either Korea or Taiwan are limited since neither country currently imports LNG, and projected future need is minimal.

The Korean Government established its energy plan for the 1980's, focusing on diversifying its energy sources. In May 1982, the Korean Electric Power Corporation (KEPCO) projected Korean demand for LNG would reach 0.159 Tcf per year in 1987. Negotiations for an LNG purchase and sales contract between KEPCO and Indonesia concluded at the end of 1982. Indonesia will begin to supply Korea with 0.106 Tcf of natural gas per year beginning in 1987 and an additional supply of 0.079 Tcf in 1989. Supplies beyond these amounts are uncertain.

In Taiwan, the Chinese Petroleum Corporation is studying the importation of LNG for consumption by Taiwan Power Company and the Great Taipei Gas Corporation. Taiwan has discussed imports of LNG with Malaysia on a government-to-government basis and is considering the import of 0.079 Tcf of gas per year as the first phase of LNG imports. Beyond these initial discussions, however, no firm commitment has been made for LNG imports to Taiwan.

Statutory controls on exports must be considered in assessing the viability of an AAPS

Exports of LNG to Japan must comply with the export provisions of ANGTA, the Natural Gas Act, and the Energy Policy and Conservation Act. The difficulties that could be encountered to realize an export authorization could affect the viability of an AAPS.

The Alaska Natural Gas Transportation Act (15 U.S.C. 719(j) provides specific limits on Alaskan natural gas exports. [11] The Congress, in ANGTA, declared that the expeditious construction of a viable natural gas transportation system for delivery of Alaskan natural gas to U.S. markets is in the national interest (15 U.S.C. 719(3)). Also, the Congress ordered the President to issue a decision by September 1, 1977, as to whether a transportation system should be approved and, if so, to designate a system to assure delivery of Alaskan natural gas to points both east and west of the Rocky Mountains in the continental United States (15 U.S.C. 719e(a)(1)). Thus, the act

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[11] The administration, through the U.S./Japan Energy Working Group, is currently examining whether additional gas could be exported to Japan and what constraints would need to be overcome on both sides.

requires that before Alaskan natural gas can be exported, the President must make (and publish) an express finding that the export will not diminish the total quantity or increase the total price of energy available to the United States. Exports of less than 1 million cubic feet per day and exports to Canada and Mexico are excluded from this requirement.

ANGTA also incorporates the export limitations of the Natural Gas Act and section 103 of the Energy Policy and Conservation Act. The Natural Gas Act (15 U.S.C. 717(b)), as amended by the DOE Organization Act (42 U.S.C. 7151(b)), requires an order from DOE, through its Economic Regulatory Administration, authorizing the export of natural gas. The Energy Policy and Conservation Act (42 U.S.C. 6212), Section 103, allows the President to restrict exports of natural gas by rule, under such terms and conditions as he determines appropriate and necessary to carry out provisions of the act. This act could cause any exports to be redirected to the lower 48 States in a time of emergency, for example.

FERC certification required for an AAPS which proposes to ship LNG to California

The transportation and sale of natural gas in interstate commerce is subject to FERC jurisdiction under the Natural Gas Act (15 U.S.C. 717). Therefore, a system which proposes to ship LNG from Alaska to California would have to be certificated by FERC under section 7 of the act (15 U.S.C. 717f). One issue in the certification process would likely be the impact of ANGTA (which established a mechanism for authorizing the system to deliver Alaskan gas to the contiguous United States) on FERC's general authority under the Natural Gas Act to certificate a second, or additional, delivery system, such as an AAPS.

Environmental problems with an all-Alaskan pipeline system

The environmental consequences of constructing an all-Alaskan pipeline system would have to be assessed prior to its approval by Federal and State governments. Based on the preliminary information provided by the University of Alaska's Arctic Environmental Information and Data Center, the major potential environmental problems unique to AAPS include seismic activity along the southern portion of the line and burial of the pipeline in Cook Inlet. In addition, the proposed routing of the AAPS would go through Denali National Park.

Seismic risk

The proposed pipeline traverses a highly active seismic area. Should the pipeline be rigidly installed in a buried mode, across earthquake fault zones, the probabilities are high that it could displace and eventually rupture with even a moderate earthquake. The probabilities for displacement appear higher along the proposed southern route of the AAPS.[12] There is a significant record of ground uplift associated with major regional seismic events between Mount McKinley and the Kenai peninsula. For example, during the period of the March 1964 earthquake, land level changes between 2 and 4 feet were common along the AAPS route on the Kenai peninsula. Historically, other seismic events have changed land elevations within the Susitna River area.

According to the Arctic Environmental Information and Data Center, given this record of seismic activity, it is doubtful that a gas pipeline could be buried without risk to the pipe itself over much of the route between the Mt. McKinley and Kenai areas. Should displacement cause the pipeline to rupture, a sweeping fire could result. If the pipeline sponsors accept this risk, then consideration during engineering design should be given to (1) special trenching and backfilling techniques[13] to avoid rigid pipeline installation and (2) use of above-ground construction across known faults. Above-ground construction of a high-pressure gasline presents more serious problems than those faced by the oil pipeline which included potential sabotage, restricted wildlife movements, and denial of public access to wildlife areas.

Cook Inlet seabed burial

AAPS is proposed to be buried in the seabed of Cook Inlet. If the pipeline is chilled, as currently proposed by the State of Alaska, the main environmental problem with seabed burial is possible ice accumulations around the pipe, resulting in a lifting of the pipe from the seabed. Pipeline rupture could interfere with ship navigation, but the escaping gas would likely have minimal effect on the Cook Inlet waters because the gas would disperse and be undetectable after a short period of time. If the pipeline remains at an ambient or ground temperature, these problems would not arise.

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[12] The TAPS line, for example, was designed to withstand earthquake activity increasing in Richter scale magnitude of 5.5 in the northern area to 8.5 in the southern area.

[13] Backfill consists of either coarse sand or gravel that is placed around the pipe to avoid rigid installation and allow movement during earthquake activities.

Crossing Denali National Park

With respect to a pipeline routed across any Federal land and especially through Denali National Park, including use of the subsurface of the Alaska Railroad easement, the Secretary of the Interior would have to grant a right-of-way under provisions of the Alaska National Interests Lands Conservation Act (16 U.S.C. 3167(c)) and the Mineral Leasing Act (31 U.S.C. 185). This right-of-way should include an assessment of the environmental consequences of the AAPS in a National Park.

OTHER OPTIONS MUST OVERCOME FINANCIAL AND TECHNOLOGICAL UNCERTAINTIES

Offshore pipeline

Ever since the early 1970's, when the President and the Congress first considered alternative proposals for an Alaskan transportation system, an offshore pipeline concept also has been considered viable by some analysts. This proposal is to route a gas pipeline east from Prudhoe Bay to the Mackenzie Delta within the inshore coastal waters of the Arctic. At an offshore facility in the Canadian Arctic, the Prudhoe Bay gas and Mackenzie Delta gas would be loaded on LNG ice-breaking tankers for shipment through the Northwest Passage to east coast markets.

This concept does offer some attractive environmental impact considerations for the United States since it avoids crossing the Arctic National Wildlife Refuge. According to the Arctic Environmental Information and Data Center, if the pipeline is buried in shallow near-shore waters where there are no large drifting ice-islands, the safety and integrity of the pipe might virtually be assured. These analysts believe all of the major environmental problems of AAPS or ANGTS could be eliminated. For example, the seismicity that does exist along the Arctic coast is extremely low in intensity and very rare. We believe this proposal would require further analysis, however, to determine its economic attractiveness and resolve its shipping uncertainties.

Marine proposals

Canadian energy companies have not limited their options for transporting arctic natural gas to the more conventional land-based pipeline. The Canadians have given more consideration to the use of ice-breaking LNG tankers and nuclear-powered submarines for transporting arctic gas. (Submarines have not been built or tested as cargo-carrying vessels.) Oil ice-breaking tankers were proven technically feasible by the voyage of the *Manhattan* in 1969, but LNG tankers have not been tested in the Arctic.

Ice-breaking tankers have been examined in the United States for future development of the National Petroleum Reserve-Alaska (NPRA) and the offshore waters of Alaska. For example, the National Petroleum Council, in a 1981 study "U.S. Arctic Oil and Gas," stated that a gas pipeline from the NPRA to Nome, Wainright, or Valdez, would be required in order to tap the estimated 10.9 Tcf of natural gas in the NPRA. Transport by ice-breaking LNG tankers would then be necessary from marine terminals at Nome and Wainright and by conventional LNG ships for transport from Valdez. In order to develop the offshore Alaskan areas of the Navarin, Norton, Hope, and Chukchi Basins, ice-breaking LNG tankers would also be needed, according to NPC.

However, many of the northern offshore basins near Prudhoe Bay, proposed for leasing by the Department of the Interior, are located in the shallow waters of the Beaufort Sea near the existing oil and gas facilities. These shallow waters may preclude the use of ice-breaking tankers or even submarines. NPC believes that the probability of utilizing a tanker transportation system in the Beaufort Sea within the next 20 years appears unlikely unless its feasibility is demonstrated by advanced operations in less severe areas in Western Alaska or Canada. Submarines would be limited to minimum operating depths of 600 to 800 feet, which precludes almost all of the area expected to be explored and leased in the foreseeable future.

The cost of building a marine terminal may also be prohibitive for a marine transportation system originating at Prudhoe Bay. No northern arctic terminal exists at present, and there is substantial uncertainty about the costs of such a facility. One company estimates a Prudhoe Bay marine terminal could cost as much as $28 billion because loading lines to ships extending 60 miles beyond the shallow waters of Prudhoe Bay would have to be constructed within tunnels to avoid ice scour problems. As a result, the total cost for direct transport of Prudhoe Bay natural gas, combined with the severe climate, may limit the use of marine options for transporting North Slope natural gas directly to markets.

CHAPTER 5

METHANOL AND PETROCHEMICAL

DEVELOPMENT FROM NORTH SLOPE FACE MARKETING DIFFICULTIES

Processing the North Slope gas into some other product for export has also received consideration. Methanol production, [1] as a full-scale alternative for using Prudhoe Bay natural gas, is not attractive for two main reasons, both economic. First, Alaskan methanol would cost more to produce than methanol from other sources. Second, even if it could be produced at competitive prices, the volume produced would overwhelm both the domestic and international methanol markets at least through 1990. A full-scale Alaskan project would produce about seven times as much methanol as current U.S. production levels. Methanol demand may grow, but predictions of growth sufficient to absorb the Alaskan methanol would have to be based on problematic new uses for methanol, such as boiler fuel. And even if markets were to improve after 1990, other technological factors could affect the viability of the methanol alternative.

The decision on whether to proceed with an Alaskan petrochemical project will depend primarily on the following economic criteria:

--Present and future markets for the petrochemicals.

--Costs of the project relative to similar projects in other geographic areas.

These criteria suggest a grim outlook for Alaskan petrochemicals.

PREVIOUS ALASKAN METHANOL PROPOSALS

The basic Alaskan methanol concept has been suggested since the period preceding the President's 1977 decision but was never investigated to the same degree as the natural gas pipeline proposals because the pipelines were seen as a less expensive method of transporting more energy. Methanol delivers only 59 percent of the Btu's of a gas pipeline because of energy losses involved in the conversion process. [2] The methanol alternative was reexamined after the well-publicized problems with ANGTS as a

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[1] Methanol is methyl alcohol, one of several alcohol fuels. For a discussion of its uses see p.76.

[2] ANGTS will deliver approximately 2,089 billion Btu's per day. Based on the same gas input level, methanol is estimated to deliver only 1,234 billion Btu's per day.

potential means of getting cheaper Btu's than ANGTS. Testimony on the subject appeared in the 1981 waiver package hearings, indicating that methanol might indeed be a preferable alternative to ANGTS.

A number of Alaskan methanol projects have been studied without detailed engineering studies. The North Slope producers have performed preliminary feasibility studies [3] which indicate an Alaskan methanol project would be a poor third choice in their ranking of transportation systems. As a result, more extensive studies were not undertaken.

The following table illustrates the wide range of Alaskan methanol delivered cost estimates from previous studies. To a limited extent, these differences could be narrowed by standardizing some of the assumptions behind each project. For example, the low cost-per-gallon figures appear to be at least partially the result of assumptions such as higher process efficiencies, different gas wellhead prices, and different inflation rates. However, a wide cost range would probably still remain after standardizing these factors, reflecting the fact that these are not detailed engineering studies.

Since the methanol proposals have not been investigated in depth, their engineering uncertainties could have the potential of turning into real problems if a detailed feasibility study were to be made.

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[3]These studies, particularly their breakdown of cost estimates and assumptions, remain proprietary and have not been reviewed in depth by GAO.

Table 6

Previous Alaskan Methanol Cost Estimates

Project element	Study authors: ARCO (1981)	CRS (1981)	OTA (1980)	ICF (1982)	Stanford University (1981)
	(billion)				
Capital cost	$17	$6.9	$23-$32	$13.7	$6
Annual expense	$1	$.66	a/$4-5.6	$1.1	-
Amount of methanol	(barrels/day)				
	500,000	408,000	520,000	500,000	400,000
Delivered cost per gallon	n/a	$0.44-$0.56	$0.80-$1.63	$0.56	$0.60

a/Includes working capital.

Sources: ICF Incorporated, "Alaska Natural Gas Development: An Economic Assessment of Marine Systems," Sept. 1982.

Congressional Research Service, "The Methanol Alternative to the Alaska Natural Gas Transportation System," Nov. 2, 1981.

"Alaska Natural Gas Transportation System (Part 2), 1981: Joint Hearings on H.J. Res. 341 Before the Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce and the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs," 97th Cong., 1st Sess.

ECONOMICS OF AN ALASKAN METHANOL PROJECT

We contracted with Dr. Carl O. Thomas [4] to perform a technical and cost analysis of an Alaskan methanol project. This report, "Methanol as a Carrier for Alaskan Natural Gas" (Nov. 1982), is separated into basic engineering and cost components. Ranges for the required amount of both components were provided in his report. Based on additional industry information, we selected specific values within these ranges to derive the cost estimates presented in this section.

Our contractor's analysis of a full-scale Alaskan methanol project is similar to past proposals; many have had several basic elements in common: (1) barge-mounted plants (the major capital cost), built in an established shipyard, towed to the North Slope, and then beached there and (2) transporting the methanol through TAPS to get the methanol to southern Alaska, with tankers carrying the methanol to its final Far East or West Coast destination. Our analysis utilized each of these basic elements because they are perceived as the lowest cost means of implementing a methanol project. We have also identified other costs associated with storing the methanol and modifying the TAPS pipeline.

Cost of barge-mounted methanol process plants on the North Slope

Barge-mounted plants, for any purpose, are intended to offset high construction costs in areas where either lack of infrastructure or difficult terrain makes normal construction methods prohibitively expensive. The barge-mounted plants, or subunits of the plant, would be built in established shipyards and then towed to their final destination where they would either be beached or left floating. In Alaska's case, they would be beached on Prudhoe Bay. By constructing the plants in a shipyard with experienced labor, both cost and time savings would theoretically occur. While no barge-mounted methanol plants have been completed, one is under construction in Saudi Arabia.

The plant itself could utilize one of several conversion processes to convert natural gas into methanol. Significant improvements in these processes have been made in past decades, resulting in improvements in process efficiency (where efficiency

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[4] Dr. Thomas, Professor of Chemical Engineering, Department of Chemical Engineering, University of Tennessee, was chosen to evaluate the methanol alternative because of his combined background in chemical engineering and prior experience with methanol proposals. Specifically, in 1975, he directed a policy analysis study for the Federal Energy Administration, "Alaskan Methanol Concept," which has been used as background for many governmental and private sector reports on the Alaskan methanol alternative.

is defined as the ratio of the energy in the methanol to the energy in the raw gas input, as measured in Btu's).

The cost for the barge-mounted methanol plants is the main cost component dominating both fixed capital and total cost estimates for the project. Our cost estimates indicate that economies of scale for plant size exist between the range of 1,000 MTPD (metric tons per day) and 5,000 MTPD. The largest current plants actually under construction are less than 3,000 MTPD. In the following analysis, 2,000 MTPD plants are assumed.

Another factor influencing costs is the level of plant efficiency. The plant efficiency level used in our analysis is 60 percent, which is slightly lower than new plant efficiency levels (projected from 70 to 80 percent efficiency.) We chose a 60-percent efficiency level to accommodate several considerations: (1) there are indications that barge-mounted methanol plants may not be able to operate at the same efficiency levels as land-based plants in established locations; (2) problems in the barge-mounted plants will be more difficult and expensive to correct, given their location, so simplicity and durability considerations may partially offset efficiency criteria; and (3) the plants will have to be self-sufficient units, not relying on the infrastructure most existing plants have available.

Given gas production (the plant's input level) of 2.4 bcfd and 60 percent plant efficiency levels, the methanol plant output level will be 74,000 MTPD of methanol (586,000 barrels/day or 8.1 billion gallons per year). If each plant is assumed to operate at 330 days per year (which is standard for more temperate locations, but possibly optimistic for arctic operations), 37 plants are required, according to our contractor. The cost per plant would be $544 million, which reflects a 60-percent contingency. [5] The total cost of these methanol plants would therefore be $20.1 billion.

The largest annual expense associated with processing methanol is probably the raw gas feedstock cost, which is determined by the natural gas wellhead price. Our analysis assumes a NGPA wellhead price of $2.28 MmBtu, for a total of $2.04 billion per year in feedstock costs. Another category of annual expense is "other operating and maintenance costs," which are generally stated as a percentage of fixed capital costs. For similar plants in the lower 48 States, operating and maintenance tends to be 8 to 10 percent of capital costs, according to industry. Our analysis

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[5] We have used a 60-percent contingency factor because this would be an enormous construction project, on a scale never before attempted on the North Slope of Alaska. This 60-percent factor also reflects shipping uncertainties for the large volume of materials required to be sealifted to North Alaska.

assumes that 10 percent operating and maintenance costs might be achieved in an Alaskan methanol project. [6] The remaining annual expenses are associated with transporting the methanol.

Costs for transportation of methanol from the North Slope

Several means of transporting methanol off the North Slope, either by land or sea, have been proposed. The marine-based alternatives include ice-breaking tankers and submarines from Prudhoe Bay. The land-based alternatives include a separate methanol pipeline or sharing the existing oil pipeline, TAPS, to bring the methanol to a south Alaskan port.

The marine-based transportation alternatives are basically similar to those discussed in chapter 4. Although methanol would be easier to transport than LNG because methanol does not require pressurized refrigerated ships as LNG does, many of the basic problems, such as expensive North Slope marine terminals, would apply to either methanol or LNG.

One land-based transportation alternative would be a separate methanol pipeline to south Alaska following a route similar to TAPS, approximately 800 miles long. This would be a small-diameter pipeline (16 to 24 inches). One industry estimate of the costs of a similar 20-inch NGL pipeline is about $2.4 billion.

The logical and cheapest means of moving the methanol off the North Slope would be to move it through TAPS, sharing the pipeline with the oil. This is the main advantage of the Alaskan methanol proposal because it avoids the need for any major new transportation system. The North Slope producers also consider this to be one of the main disadvantages of the proposal since, by not developing a new transportation system, development of additional offshore gas deposits would be hindered.

Methanol could move through TAPS in either of two ways--(1) in an emulsion (mix) with the oil or (2) batched (alternating portions of oil and methanol) with the oil. Batching is generally seen as the preferred alternative because separating the crude oil and methanol would be easier and cheaper. From the end of TAPS in Valdez, methanol could be transported in standard oil tankers to its final destination. While it is generally agreed that this proposal is technically feasible, moving oil and methanol in the same pipeline has not been tested on a full-scale basis, and therefore, some questions remain.

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[6] This may be an overly optimistic assumption. However, this is offset by the fixed capital costs, which are already considered to be high, since the methanol synthesis plants have a 60-percent contingency added to their costs.

A large annual expense--pipeline user charges--would be associated with this transportation mode. This expense is the fee charged for transporting the Alaskan methanol through TAPS, which we assume is a $6.00-per-barrel charge (the current charge for transporting oil through TAPS) at least during the early years of the project. [7] Transporting 586,000 barrels/day at $6.00 per barrel would cost approximately $1.2 billion per year.

A final annual expense associated with the transportation segment of the project would be tanker fees for methanol shipment from Valdez to the final port of entry. This cost element would be dependent on many factors such as destination, nationality of ships, tanker markets, and potential for transporting material on return trips. For estimation purposes, our contractor used a $0.70-per-barrel charge for tanker transport from Valdez to the West Coast. Based on this figure, transporting 586,000 barrels/day would give a yearly total of $140 million in tanker fees.

Cost of other facilities

Other fixed capital costs would include facilities to separate the oil from the methanol and water at Valdez. Gravity would cause most of the oil and methanol to separate while the batch is stored in tanks, but water would remain in the methanol and require removal. The separation facility assumed in our analysis would be located in Valdez to avoid high North Slope construction costs yet limit the additional tanker costs of carrying water to market. However, the facility might also be located on the North Slope if considerations such as the cost of moving useless water through TAPS and potential corrosion were a problem. Both the size and location of required separation facilities would require further extensive study.

If methanol were transported through TAPS, modifications to the oil pipeline system would be required. Additional pumps and storage facilities would be required to handle the increased pipeline throughput. Storage facilities would be needed on the North Slope, at Valdez, and at the West Coast port of entry. The cost for all these facilities is an estimated $1.5 billion to $2 billion. This estimate of the costs of south Alaskan separation and other facilities is based on discussion with the producers about the results of preliminary testing they have undertaken.

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[7] The actual tariff charged to methanol could be higher or lower depending upon the cost of modifications to TAPS, actual throughput, and whether FERC allocates recovery of the cost of constructing the pipeline to the methanol.

Table 7

Costs of Alaskan Methanol Project

	1982 dollars	Capital costs in 1989 dollars (note a)
	----------(billions)----------	
Fixed capital costs (note b)		
Methanol synthesis plants	$20.1	$31.6
Other facilities	2.0	3.1
Total	$22.1	$34.7
Annual expenses		
Feedstocks	$2.04	$3.20
Tanker fees	.14	.22
TAPS user charges	1.16	1.82
Other operating and maintenance	c/ 2.21	3.47
Total	$5.55	$8.71

a/Calculated by GAO using inflation estimates of app. III.

b/Includes an unspecified amount of interest on funds used during construction.

c/Ten percent of fixed capital costs.

Source: Calculated from Dr. Carl O. Thomas, "Methanol as a Carrier for Alaskan Natural Gas," Nov. 1982.

Resulting methanol costs per gallon: more expensive than other sources

Our contractor's report provides a range of methanol costs from \$0.80 to \$1.83 per gallon based on different assumptions. (See app. XI.) The system elements we have previously described could initially require revenue of approximately \$14 billion per year. When this total is divided by methanol production of 8.1 billion gallons per year, the cost per gallon of methanol needed to cover these revenues would be \$1.08, or about \$16.72 per MmBtu. (See app. VIII for a discussion of how delivered product costs are derived.) The average price over 15 years would be about \$1.17 per gallon, or \$18.11 per MmBtu.

Current U.S. sources are supplying chemical-grade methanol to the U.S. West Coast at about \$0.70 per gallon; therefore, we believe that \$1.08 per gallon of methanol would be noncompetitive in the U.S. chemical market. If methanol were used as a transportation fuel, it would have to compete with gasoline, which delivers twice the Btu's of methanol. Its cost, therefore would need to be roughly half that of gasoline to be competitive. Early 1983 spot market prices for regular gasoline were about $0.83 per gallon. At our estimated delivered price of $1.08 per gallon, Alaskan methanol would have difficulty competing with gasoline.

POTENTIAL PROBLEMS WITH AN ALASKAN METHANOL PROJECT

There are several potential problems with an Alaskan methanol alternative. The major problem is the poor marketability of the large methanol supply that an Alaskan project would produce. Other technical or contractual factors could also affect the project. These problems would include the reluctance of oil pipeline owners to permit methanol to be carried in their pipeline. One suggestion to relieve these problems, constructing the project in stages over an extended period of time--the incremental approach--would do little, if anything, to solve these problems.

A major question regarding batching methanol through TAPS is whether there would be adequate room for methanol in the pipeline. The pipeline's current oil throughput is about 1.6 Mmbd (million barrels per day). However, further use of chemicals and additional pumps to increase the speed of the oil flow may possibly increase TAPS' capacity to 2.5 Mmbd. Since Prudhoe Bay's annual average oil production is limited by State order to no more than 1.5 Mmbd and production from the field is predicted to decline by the end of the decade, it would appear that there will be room for up to 1 Mmbd of methanol. However, this may not be the case because, according to industry plans, new arctic oil fields may well be under development through the 1990s. Thus, the available TAPS capacity for methanol shipment cannot be definitively estimated.

Another potential problem is the provisions of the current Agreement for the Operation and Maintenance of TAPS, which prohibit the pipeline from carrying anything except petroleum. Agreement from all eight owners (not all of whom have an interest in Prudhoe Bay gas) would be required to amend the TAPS agreement in order to allow methanol to be transported through TAPS. Both the owners and the pipeline's operator (Alyeska Corporation) may well be reluctant to change the agreement and commit space to methanol because of the future potential for more oil and the possibility that methanol might damage any oil shipped.

The actual level of risk involved with transporting the methanol through TAPS appears uncertain because many technical questions remain to be resolved. One potential problem is the possibility of methanol's corroding TAPS. (Methanol is known to corrode several types of metals, including the steel composing TAPS). However, this problem may be solvable by the addition of certain corrosion-preventive chemicals, according to industry officials.

Another aspect of batching which would require further investigation is the treatment of the interface (boundary layer) between the methanol and crude oil batches. Methanol and crude oil separate naturally, which would take care of a good deal of the interface, and possibly the remaining interface would be negligible. However, it is also possible that the interface may not be negligible and that facilities may be required to separate the two substances. No Government regulations currently cover shipping oil and methanol in the same pipeline. The Department of Transportation's Office of Pipeline Safety will require further answers to the above questions to develop safety criteria and regulations.

<u>Incremental construction will not eliminate problems of a full-scale project</u>

Another element common to many of the methanol proposals is the use of incremental, or phased, construction. This would involve the construction and implementation of several plants per year, with a buildup to full-scale production occurring over several years. This approach would theoretically have certain advantages over one-step construction: (1) revenues from early plants could be flowing before later plants are built, which would limit the initial capital required; (2) a learning curve might develop which could decrease risks and improve the economics of later plants; and (3) marketing problems might be eased as slower demand buildup could occur, easing methanol absorption.

However, increments could also face the same marketing problems as a full-scale project. For example, if the full-scale project assumed in our report were divided into fifths, these increments would still involve the operation of seven world-scale methanol plants (based on the 37 plants needed for a full-scale project as previously mentioned). This additional production of 1.6 billion gallons per year would double current U.S. production of 1.1 billion gallons and would obviously raise marketing problems similar in nature, if not extent, to a full-scale project.

Another problem with an incremental approach, particularly if less than 100 percent of the North Slope gas is used, is that this cannot be viewed as a project comparable to a natural gas pipeline. An incremental project could use much less of the Prudhoe Bay gas and, therefore, should not be evaluated as an alternative to a gas pipeline. We have chosen to evaluate only a full-scale methanol project.

Methanol markets must develop before United States can absorb large Alaskan volumes

Methanol from a full-scale Alaskan project will not be absorbed in the market under current circumstances. Alaskan methanol priced near $1.08 per gallon would not be able to compete with methanol from current U.S. sources priced at about $0.70 per gallon. This price differential is particularly important because of the large quantity of Alaskan methanol that will have to be sold. In 1982, the United States produced about 1.1 billion gallons of methanol. A full-scale Alaskan project producing 8.1 billion gallons would cause a seven-fold increase in domestic production levels. For this amount to be absorbed, new uses of methanol will have to develop, but the high price of Alaskan methanol would likely limit this development.

Methanol currently has two broad applications--chemical and fuel use. Chemical applications now use about 95 percent of total methanol produced, with fuel applications consuming the remaining 5 percent. While chemical demand dominates the current market, the major new thrust is the expansion and creation of methanol fuel uses to substitute for petroleum-based fuels such as gasoline and fuel oil. If any major growth in the methanol market is to occur, it will probably happen because of increased demand for methanol as a fuel.

Chemical uses for methanol unlikely to experience significant growth

About half of the methanol used in the chemical sector goes to the production of formaldehyde, which is used in making resins and insulation. This methanol demand is primarily determined by growth in the forest products industry which, in turn, is affected by construction industry growth.

The next largest use of chemical methanol is as a solvent for the chemical, paint, and textile industries. These two uses, along with the remaining traditional chemical uses, are closely tied to the chemical markets which are currently depressed. (See p. 80.)

Fuel uses for methanol offer largest potential to expand demand

Only 5 percent of methanol is currently used for fuel. About half of this amount is used in the production of gasoline octane enhancers. Some methanol is consumed directly as automotive fuel (mixed with gasoline in low-level blends--5 percent methanol to 95 percent gasoline). A very small amount is used, on an experimental basis, as a "neat" (mostly methanol) automotive fuel for several fleets of automobiles. A potential use of methanol is its conversion to gasoline processes such as Mobil's methanol-to-gasoline process. Another proposed fuel use of methanol is in powerplants. There are no firm predictions on the future methanol demand from each of the above uses.

Advocates strongly push increased methanol use, based on benefits such as decreased pollution, decreased petroleum imports, and improved national security. However, these reasons, even when combined with low costs, may not lead to vast increases in methanol use. According to the Ford Motor Company, automobile makers are reluctant to build an assembly line for methanol cars if a methanol fuel supply (and distribution system) is not readily available. Simultaneously, methanol producers are reluctant to produce large new supplies before the vehicles (and hence demand) exists. The North Slope producers, in particular, have told us that they are not in the business of developing a methanol market. A similar problem exists with the use of methanol as a utility fuel according to the California Energy Commission. Until a long-term, low-cost methanol supply can be firmly guaranteed, the utilities (and utility commissions) will not demand large amounts. (See app. XII for a further discussion of fuel uses for methanol.)

As we have previously stated

> "* * * the major obstacle impeding achievement of methanol's potential is the problem of simultaneously developing methanol production, a distribution network and suitable vehicles." [8]

We do not believe that swamping the United States and the world with Alaskan methanol is a reasonable means of overcoming this problem.

If the market outlook were to improve later in the 1990's, an Alaskan methanol project might become competitive. This would require that methanol become attractive as a neat automotive fuel or a widespread utility fuel to significantly increase demand. Since predictions of methanol markets beyond 1990 are tenuous, we cannot rule out the possibility of a more viable project in the long term as market situations change.

<u>Methanol markets are expected to remain small relative to potential full-scale Alaskan methanol production</u>

As the following table indicates, a world methanol supply shortfall is not expected until 1990. However, the size of this shortfall pales in comparison to the output of an Alaskan methanol project--24 million tons per year, almost 10 times the size of the predicted deficit. Moreover, a world methanol surplus is expected to continue at least through 1985.

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[8] Statement of F. Kevin Boland, GAO, before the Subcommittee on Fossil and Synthetic Fuels of the House Committee on Energy and Commerce, Sept. 24, 1982.

Table 8

Projected World Methanol Supply and Demand

	1979(est)	1985	1990
	----------------(000 tons)----------------		
Supply	11,255	18,500	20,155
Demand	10,435	15,225	22,900
Resulting supply surplus (deficit)	820	3,275	(2,745)

Source: World Bank, "Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries," Apr. 1982.

These pessimistic predictions could be partially offset by some of the following considerations. First, the methanol demand estimates may be overly conservative. These estimates reflect methanol use only in currently economic applications--chemicals, gasoline octane enhancers, and limited low-level fuel blends. Second, the estimates are based on the assumption that the price ratio between methanol and gasoline will remain the same in the future. If methanol prices should fall relative to gasoline prices, methanol may become more attractive as a fuel. Third, the 1990 U.S. supply shortfall as predicted by the World Bank is almost as large as the world shortfall figure. U.S. methanol imports, especially from other North American suppliers, such as Canada, may rise, according to this study.

However, even after considering these factors, we believe an Alaskan methanol project to use all the North Slope gas is not viable. The size of both the U.S. and world deficits is still small relative to potential Alaskan production, and investors will probably require strong evidence that a large increase in methanol demand will occur in the future to absorb Alaskan production before a methanol project can be considered economical.

OUTLOOK FOR A PETROCHEMICAL INDUSTRY IN ALASKA

Petrochemicals are chemicals derived from crude petroleum and natural gas feedstocks. [9] Petrochemical production usually occurs in conjunction with crude oil refining or natural gas

[9] The natural gas feedstocks are formed into primary petrochemicals, such as ethylene. These primaries are then refined into intermediate petrochemicals, which are in turn formed into petrochemical products. The major end uses for ethylene are fabricated plastics, antifreeze, and fibers.

conditioning. For example, in Alaska, petrochemical production was proposed in 1977 to use the State's royalty share of the crude oil from Prudhoe Bay. The Alaska Petrochemical Company was formed to carry out this venture. However, the project never developed because of difficulties involving economic feasibility and financing.

One of the main advantages of any world-scale petrochemical plant in Alaska is that it would significantly expand the State's industrial base. Most of the other energy projects in Alaska involve exporting a natural resource with little value added within the State. A petrochemical project would be an exception to this trend. Skilled and highly paid labor would be attracted to the State on a long-term basis, in contrast to the boom/bust cycle typical of other projects.

The idea of a petrochemical project was revived with the proposals for the development of the North Slope's natural gas resources. Alaska's natural gas liquids could provide sufficient feedstocks for two world-scale petrochemical plants. After consultant studies indicated a petrochemical project might be feasible, the State solicited proposals from the petrochemical industry to undertake a comprehensive feasibility study. The State selected a group of nine companies, the Dow-Shell Group (named for Dow Chemical Company and Shell Chemical Company) to undertake the study. The resulting $5.5-million 1981 study, "Alaska Petrochemical Industry Feasibility Study," came to the conclusion "an NGL project [10] in Alaska does not appear feasible at current crude oil values." For a project to be feasible, the study found that oil prices would have to rise significantly to about $50 per barrel.

The study also found that Alaska's high construction cost [11] would need to be offset by lower feedstock prices. Specifically, it was estimated that Alaskan ethane would have to be priced at approximately two-thirds the price of U.S. Gulf of Mexico ethane prices to offset the higher costs of an Alaskan project. Other conditions deemed necessary for a feasible Alaskan project were (1) State support for the infrastructure necessary to accommodate a large project labor force (through low-interest bonds) and (2) a decision on a natural gas pipeline, so that the gas producers would be able to begin negotiations with potential NGL buyers.

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[10] An NGL project is a prerequisite to a petrochemical project.

[11] The study evaluated six sites--five along the southern coast of Alaska and one in an interior location near Fairbanks.

Since that report was published, the outlook for a feasible petrochemical project has worsened. Crude oil prices have been declining toward $30 per barrel (1982 dollars). But perhaps most importantly, according to Dow-Shell:

> "A worldwide recession is occurring which has a negative impact on the markets and prices of chemicals and the associated feedstocks. This poor market is coupled with an associated excess supply of petrochemical feedstocks. The recession has also resulted in a decreased demand for petrochemicals and a downward trend in projecting future growth rates."

Based on the previous higher growth rates, Dow thought the market would be able to absorb Alaska's additional ethylene output by 1985-86. With the lower industry growth rates, this date is significantly postponed, and a future market for Alaskan petrochemicals is in doubt.

GROWTH IN WORLD MARKETS FOR PETROCHEMICALS DECLINING

In the past few years, growth rates in the petrochemical industry have declined worldwide. Through the 1960's, the growth rate of the petrochemical industry was twice that of the gross national project (GNP); now it is only about equal to the GNP growth rate. Operating rates for most parts of the industry have declined and overcapacity now exists. For example, the plant operating rate for ethylene, one of the potential petrochemical products from Alaska, is estimated at 65 percent in 1982. According to industry experts, overcapacity is predicted to continue worldwide throughout the decade.

There are several reasons for the decline in petrochemical growth, many of which appear to reflect industrial maturity. Growth in technological improvements and savings from economies of scale have leveled off since the early- and mid-1970's. Growth has also leveled off in some of the main industries using petrochemical products (e.g., automotive and housing).

The petrochemical industry is one of the most energy-intensive industries, using large quantities of hydrocarbons as both feedstocks and fuels. The industry grew up in a period of cheap energy. When the energy crisis developed in 1973-74, the petrochemical industries in countries relying heavily on energy import were hardest hit (Japan, Western Europe). According to industry experts, the U.S. petrochemical industry felt fewer of the impacts because U.S. producers have abundant supplies of natural gas liquids from domestic natural gas, whereas the Japanese and Europeans were almost totally reliant on imported feedstocks.

Because of this diversity in feedstocks, the U.S. advantage was only partially reduced with the phasing out of domestic oil price control in 1981. However, many in the industry believe that the competitive advantage will be more severely limited by natural gas price deregulation under the Natural Gas Policy Act of 1978. The act will result in decontrol of large portions of the interstate gas market in 1985 which is predicted to increase natural gas prices. As natural gas prices rise, natural gas liquids are likely to become more valuable, and their prices will also rise. U.S. petrochemical prices will approach world levels, and export growth will be limited, just when an Alaskan petrochemical project might be commencing. In an attempt to cope with these problems, the industry is moving toward an increased emphasis on downstream production (i.e., specialty chemicals) and increased foreign production. These shifts indicate that current petrochemical overcapacity is structural and will not go away with the current recession.

Shift to downstream production

Chemicals range from commodity petrochemicals (such as ethylene), which are produced and sold in bulk volumes at low profits, to specialty chemicals which are highly differentiated, and low-volume products. According to industry experts, companies emphasizing specialty chemicals have tended to have higher profit rates than large, diversified chemical companies because specialty chemicals are relatively less energy- and capital-intensive than commodity petrochemicals, and are therefore hurt less by increasing energy and capital costs. Dow Chemical recently cited reductions in projected commodity petrochemical demand and a shift to specialty products as the main reason for its withdrawal from a large Saudi Arabian petrochemical project.

This downstream shift is relevant to Alaska because in-State production would consist of commodity petrochemicals which would be shipped out-of-State for further processing. Thus, an Alaskan project would be entering a segment of the industry which is already experiencing overcapacity and low profits.

Shift to foreign producers which offer incentives to offset higher production costs

Foreign countries are becoming increasingly interested in petrochemical projects and are willing to subsidize traditional petrochemical producers which enter their country, in effect exchanging abundant, cheap feedstocks for technological and marketing expertise. Other countries, especially Saudi Arabia and Canada, have long had abundant sources of NGL in their oil-associated natural gas, but this resource was seen as secondary to the oil and, thus, was often flared. This situation changed during the 1970's as countries began seeing the potential for moving downstream and creating a large, highly capital intensive, new processing industry. Petrochemicals were seen as a way of promoting industrial development, as opposed to simply exporting natural resources with no value added.

The market impacts, as other countries enter the competition, will be significant. Industry experts predict that the current major petrochemical-producing areas (U.S., Japan, and Western Europe) will lose part of their market share to the new entrants--Saudi Arabia and Canada (particularly the Province of Alberta). These countries have already begun plant construction and have the largest gas reserves.

Saudi Arabia to play key role in future petrochemical supplies

Saudi Arabia will probably be the most important new entrant into the market because of its high level of government support. The Saudi Government created the Saudi Arabian Basic Industries Corporation in 1976 to head the development of non-oil industries, primarily petrochemicals. In addition to large expenditures for infrastructure development, about $20 billion is being spent on a gas-gathering program, begun in 1975 and estimated to be completed in 1983. This system will eventually collect 3.2 bcf per day of oil-associated natural gas. Large amounts of the gas will serve as feedstocks for the petrochemical industry. Several Saudi world-scale projects producing ethylene or ethylene derivatives are predicted to come on stream in the 1980's.

This huge development effort is going on despite the current world petrochemical overcapacity, thereby ensuring that overcapacity will continue throughout the decade. The Saudi Government has stated that it hopes to capture 5 percent of the world chemical market by 1990 and 15 percent by 2000. That government is backing the effort in order to achieve industrial development. The private companies are investing in the effort because of the various incentives given by the Saudi Government, such as low or interest-free loans, subsidized water and electricity, oil entitlements, and cheap feedstocks.

Since most of the future petrochemical siting decisions will be made by these multinational companies, which have numerous siting options, cost comparisons between locations seem significant. Various types of foreign government subsidies influence these costs differently, according to specific government policies. According to an International Trade Commission analyst, specific information on each country's subsidies is difficult to obtain for two reasons: (1) countries prefer to limit knowledge on what they are willing to give in order to keep a strong bargaining position and (2) they do not want to reveal the extent of subsidization for fear of being accused of unfair trade practices. However, some estimates have been made which allow the following rough comparisons, based on Alaskan, Saudi Arabian, and Canadian petrochemical industries.

Our cost comparison emphasizes two cost categories: feedstocks (fuel) and construction. A third cost category--transportation--has not been addressed for two reasons. First, transportation is not as large a cost element as the others. Second, transportation charges are difficult to measure since they depend on ship nationality, type of financing, and other factors. Feedstocks and construction costs can outweigh the charge for the distance travelled to a market. Therefore, whether an Alaska petrochemical plant is closer or farther from a market than its competitors will probably not be a determining factor in a decision to construct an Alaskan petrochemical plant.

Feedstock costs are the most important factor in plant location

The feedstock cost component, which constitutes between 35 and 80 percent of total petrochemical production costs, is the most important cost element because in addition to its size, it is the most variable component. The price of the feedstocks depends largely on their alternative value because most petrochemical feedstocks can also be used as fuel. Ethane, which would be one of the main feedstocks for an Alaskan petrochemical project, can also be sold as part of a natural gas pipeline's output. If natural gas prices rise in the lower 48 States and Alaska due to deregulation, the incentive to extract ethane as a feedstock from the natural gas stream would be reduced. Therefore, petrochemical producers would pay a premium to use ethane as a feedstock. This increased price could be significant because given the continued poor profitably of commodity petrochemical production, petrochemical producers will likely limit the use of high-cost feedstocks, according to a Commerce Department analyst.

According to industry analysts, the Saudis will price ethane at about $0.56 per mcf through 1985, about one-sixth its real value in the United States (based on a U.S. 1985 average wellhead gas price of $3.36 per mcf). While Canadian ethane prices are currently in a state of flux, the long-run potential for relatively cheap feedstocks still exists since Canada has abundant gas supplies and an extensive gas delivery system. The Canadian industry is asking its government to develop a long-term petrochemical policy to allow the industry to compete successfully.

Construction costs must compete with Gulf of Mexico

To compare plant construction costs in different locations, regional cost indexes are developed, based on past construction experience. Costs for the U.S. Gulf of Mexico (where petrochemical plants are heavily concentrated) are often used as the base figure. Alaskan construction costs are then between 1.7 and 2 times this base cost, depending on whether an interior or southern Alaskan area is chosen. Canadian plant construction costs are about 1.35 times the base figure,[12] and Saudi Arabian costs are even greater than the Canadian costs. The additional costs of building a plant in Alaska would have to be offset for a project to be competitive.

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[12]Based on interior Canadian locations in Alberta and subject to availability of trained personnel.

CHAPTER 6

OTHER ALTERNATIVES TO USE OR TRANSPORT NORTH SLOPE GAS

In examining other methods to use or transport North Slope gas primarily within the State of Alaska, it is difficult to find an alternative which could use significant quantities of the Prudhoe Bay gas. Our review of uses within Alaska--for fuel, enhanced recovery of heavy oil on the North Slope, flaring or continued reinjection of the gas at Prudhoe Bay, and converting TAPS to a gas pipeline--demonstrates that these alternatives (1) would use only minimal amounts of the gas available on the North Slope and (2) may require tradeoffs between the value obtained for the gas and other fuels.

FUEL USE WITHIN ALASKA CAN USE ONLY LIMITED AMOUNTS OF NORTH SLOPE GAS

Alaska's population is centered around the Anchorage area, with 75 percent of the State's inhabitants living in the Railbelt area [1] between Anchorage and Fairbanks. Because Alaskans have clustered in this area, the State's energy needs can largely be addressed by looking at the needs of this particular region.

Alaska's small population (402,000 in 1980) has access to a variety of energy supplies. Coal, hydroelectricity, oil, and Cook Inlet natural gas all provide fuel and electrical power to Alaska. The Anchorage area, where Cook Inlet gas furnishes 88 percent of the electric power and heats 60 percent of the households, is the major Alaskan gas market. In order for Prudhoe Bay's gas to reach a substantial market, it must compete with Cook Inlet gas supplies, which would be difficult.

Cook Inlet gas currently provides cheap supplies for electrical power in quantities that are likely to remain available over the next 20 years. The planned transmission intertie between Anchorage and Fairbanks would make these supplies available as power to Railbelt electrical consumers as well in late 1984. One of the arguments in favor of State funding of the intertie was that it would make cheap Cook Inlet gas accessible to consumers in the Northern Railbelt. At the same time, however, if the North Slope gas were transported to South Alaska, consumers' gas costs could increase since Cook Inlet's gas producers would then have the opportunity to sell more of their gas as LNG to Japan.

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[1] Alaska's "Railbelt" is a term used to describe the area surrounding the Alaska Railroad's north-south corridor connecting the State's two largest cities.

There has been significant debate within the State over how much growth in population and energy demand could occur in the next decade. We believe, even under optimistic assumptions (such as gas penetration of 50 percent of the northern Alaskan heating market and all gas-fired electric power generation), it is unlikely that demand for North Slope gas would exceed about 18 to 20 bcf per year for power and heating or 10 days of the annual gas production from Prudhoe Bay. (This figure represents 15 bcf for projected Fairbanks area heating and power use and could cover an additional 30 percent (5 bcf) growth in demand.) Moreover, this is less than one-eighth of the Prudhoe Bay gas.

The cost of meeting this minimum demand with Prudhoe Bay gas is likely to be prohibitive. Using North Slope gas as fuel or for electric power generation requires that the energy be transported 450 to 800 miles to its market. In our opinion, without State subsidies, the consumer must ultimately bear the full cost of this transportation since there are no large communities en route to Fairbanks which could utilize the gas and share its tariff. For example, a 20- to 25-inch-diameter pipeline to Fairbanks would cost several billion dollars to construct according to industry estimates. A pipeline to Fairbanks would likely require State financing of construction in order to reduce the cost of the delivered gas and make it attractive to consumers. The producers are not really interested in such proposals because (1) the volume of gas needed to serve 54,000 people is so much less than what a full-scale pipeline project could use and (2) ANGTS or an all-Alaskan pipeline would offer the same access to gas for local needs. In addition to a pipeline from Prudhoe Bay to Fairbanks, a gas-distribution system for the Fairbanks community would also need to be developed at substantial costs.

The costs involved in constructing an electrical transmission system on the North Slope to serve Alaskan markets are enormous. For example, in 1972 the Alaska Power Administration estimated that the 26 Tcf of gas at Prudhoe Bay could support an 8,000-megawatt power plant (six times the size of the State's forecasted need) for 50 years at a cost of $10.2 billion (1982 dollars).[2] The study also concluded that "* * * the Railbelt area could be better served by local generation than by more remote North Slope generation."

Other potential uses for North Slope gas include its continued use for oilfield operations, use of some gas liquids as propane fuel, development of compressed natural gas as a vehicle fuel, and possibly a large methanol plant in Fairbanks. As discussed later in this chapter, oilfield operations continue to be a major consumer of North Slope gas. The other options,

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[2]Alaska Power Administration, "North Slope Transmission Study," July 1982.

however, do not serve large markets in Alaska. Propane suppliers are serving largely rural Alaskan customers and have used Cook Inlet gas with only 32 percent of total propane supplies being imported. (In 1980 Alaska used only 190,000 barrels of propane.) Compressed natural gas for motor fuel has not been widely used in the United States. A single 5,000-MTPD methanol project, as proposed by some Alaskans,[3] could consume only about 1.46 Tcf of North Slope gas, but as with the propane and vehicle uses mentioned above, a transportation system must first be in place to move the gas from the North Slope.

Our estimates show that without a transportation system, about 12.5 percent of the Prudhoe Bay raw gas would be used within the State for oilfield operations on the North Slope. (See p. 91.) With a small pipeline to Fairbanks, another 2 Tcf might be utilized within the State (especially if plans for a methanol project are pursued). If power were generated on the North Slope, it is unlikely to be utilized within the State since only a small amount would be required to meet the needs of northern Alaskans. Therefore, the maximum in-State use without a major transportation system would be with a small pipeline to Fairbanks for total consumption of approximately 6 Tcf, or 23 percent of Prudhoe Bay's natural gas. If more gas is discovered in the North Slope, in-State needs would be an even smaller proportion of the ultimate resource potential of northern Alaska.

Fuel Use Act could preclude any use of North Slope gas for electricity generation

Prior to any new powerplant's use of Prudhoe Bay gas, the utility would have to obtain an exemption from the prohibition on burning gas in new powerplants contained in the Powerplant and Industrial Fuel Use Act of 1978 (42 U.S.C. 8301). This act prohibits use of natural gas as a primary energy source in any new electric powerplants and major fuel-burning installations constructed or acquired after November 9, 1978. However, the act also provides numerous grounds for temporary (5 years) and permanent (life of the plant) exemptions from these prohibitions.[4]

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[3]Alaska Interior Resources Company, Inc., "Methanol/Energy Complex - Fairbanks, Alaska," Oct. 2, 1981.

[4]The Interior Department Appropriations Act for Fiscal Year 1983 (P.L. 97-394) provides a statutory exemption for the use of natural gas by new Alaskan powerplants which petition DOE before December 31, 1985. The exemption, however, does not apply to Prudhoe Bay natural gas.

DOE's Economic Regulatory Administration administers this act for the Secretary of Energy. One Alaskan analyst suggested that the grounds for an exemption to this act could be

"(a) lack of alternate fuel supply for the first 10 years of the useful life of the facility,

(b) lack of alternate fuel at a cost which does not substantially exceed the cost of imported oil,

(c) site limitations,

(d) inability to comply with applicable environmental requirements, and

(e) inability to use alternative fuel because of a State or local requirement."

ENHANCED RECOVERY OF HEAVY OIL IN THE KUPARUK FIELD

We analyzed the use of Prudhoe Bay gas for recovery of West Sak petroleum (a heavy oil geological formation that exists in the zone overlapping the Kuparuk field in Alaska). Testing of such recovery is in the initial stages, so there is no way to determine the ultimate viability of such gas use at this time. However, it is likely that North Slope gas could be used as a fuel for some enhanced recovery program at Kuparuk in the absence of an alternative use for the gas.

ARCO's test program

The Kuparuk field, discovered in 1969, is located 30 miles northwest of Prudhoe Bay on Alaska's North Slope. ARCO Alaska, Incorporated, is the field's operator, producing an average of 87,000 barrels of oil per day. Five potential reservoirs are located within the Kuparuk field, two of which ARCO is studying in detail for heavy oil recovery--the West Sak sands and the Ugnu tar sands.

The West Sak sands are a highly viscous (17 to 23 degrees API),[5] cold (46 degrees F), and relatively shallow (3,742 to 3,842 feet) oil deposit. Estimates are that from 18 billion to 40 billion barrels of oil are in place, but the amount which is ultimately recoverable is unknown. While the geologic characteristics of the deposit are similar to heavy oil projects in the lower 48 States, the oil's depth and temperature make it so viscous that it will not flow. Moreover, the West Sak sands are located close to

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[5]API gravity is the standard American Petroleum Institute method for specifying the density of crude petroleum in degrees.

the permafrost level (1,000 to 2,000 feet), and according to USGS, the permafrost itself could be the trapping mechanism for the oil.

The oil's viscosity and the existence of permafrost in the Kuparuk field require consideration of alternative recovery technologies--sometimes called tertiary or enhanced recovery techniques--some of which have been practically applied and others of which are experimental. According to an ARCO official, the permafrost cap for the West Sak sands presents a problem only if heat technology methods like steam and combustion are used. Heat generation for steam recovery on the surface could melt the permafrost if the equipment is not properly insulated. According to a Chevron expert, steam generators could be insulated from the permafrost by using gravel pads as is done at Prudhoe Bay. Insulated casing and pipe are also available to reduce heat loss. A more experimental alternative is "down hole" steam generation, where the generator is placed at the bottom of the well. But this has not been commercially proven, according to a Getty official.

ARCO officials believe there is no way to determine now whether recovery of heavy oil in the Kuparuk field is an alternative to the ANGTS pipeline. They believe recovery of the West Sak oil depends on a breakthrough in technology resulting from its current test program. ARCO officials told us that the technology probably exists for recovering West Sak sands heavy oil, but that the economics of using such technology in an arctic environment needs to be proven. According to an ARCO Alaska regional engineer, ARCO is studying the economic feasibility of a range of techniques including mining, combustion technologies, steam injection, and combinations of these techniques.

The first phase of ARCO's study includes gathering data on the West Sak sand reservoirs to determine how the reservoirs will act under different recovery scenarios. Data acquisition will include drilling onsite wells during 1983. According to an ARCO official, actual field testing of any recovery process is several years down the road. Moreover, ARCO officials generally believe that it could be 5 to 10 years or longer before any commercial production of the West Sak sands oil occurs.

Gas used for enhanced recovery could be substantial, but need not come from Prudhoe Bay

The amount of natural gas that might ultimately be used for the West Sak sands oil recovery program is unknown at this time. Gas could be used (1) directly as an injectant to help move the oil or (2) indirectly as fuel for a heat-generation technology. Industry and State analysts believe it is more likely the gas would be used as a fuel source, since gas injection alone is unlikely to have much effect on improving the flow of this heavy oil. Rather, increasing the temperature of the oil by applying some form of heat would be more effective in reducing its viscosity.

Estimates of the amount of gas needed to recover this heavy oil vary. Enhanced recovery technologies can be major fuel consumers. For example, Chevron's recovery of heavy oil in California consumes 1 barrel of oil to produce 2 to 2.5 barrels of oil. DOE estimated that in 1980, recovery of heavy oil using steam drive techniques cost from $21 to $35 per barrel. Yet, using Prudhoe Bay gas as a fuel remains attractive to the North Slope producers as long as the gas is not marketable and has no other value.

ARCO is not necessarily assuming that the natural gas for a tertiary recovery program will come from Prudhoe Bay, but rather is considering all options including the use of Kuparuk, Lisburne field, and OCS Sale 71 natural gas. The best approach is likely to be using whatever gas is available elsewhere in the Kuparuk field first because it is considered a "free" resource for use anywhere on the State's lease. Associated gas is currently being reinjected at Kuparuk at a rate of 32 mcf a day and is expected to increase as primary oil production increases.

Cost is a drawback to using Prudhoe Bay natural gas for heavy oil recovery of the West Sak sands. Prudhoe Bay and Kuparuk are separate fields with separate unit boundaries and operating parties. To move the gas between these fields, it would first have to be sold between owners and then the State would collect its royalty for any gas which leaves a lease unit.

CONTINUED REINJECTION OF THE GAS IS POSSIBLE THROUGH THE 1990's

Since the production of oil from Prudhoe Bay began in 1977, opinions have abounded as to how long the oil producers can continue to inject the gas being produced with their oil back into the reservoir. All of the North Slope producers and the State of Alaska regulatory authorities agree that there is no reservoir management problem at Prudhoe Bay and that gas reinjection can continue indefinitely. There is no near-term deadline, therefore, by which the producers must produce and sell their gas or risk damaging the reservoir.

An analysis for the State shows that the absence of gas sales helps rather than hinders oil production. For example, the Prudhoe Bay waterflood program (using water to force additional oil out of the field) is projected to increase oil recovery 11.2 percent over a scenario where the gas is sold and no injection program occurs. In addition, the life of the field increased from 24.2 years to 37.5 years. According to the State's report, the maximum life of the field and the maximum oil recovery were predicted to occur with this reinjection program but no gas sales.

Using the State's analysis and given that oil production started in 1977, the point at which reinjection would stop and recovery of the remaining Prudhoe Bay oil would be uneconomic could be 2034. Several factors, however, could reduce this lifespan, especially the cost of continued reinjection.

The North Slope producers believe that a point may come where the cost of reinjecting the gas exceeds the value received for the oil being produced. One company suggested that at the point where the costs of additional compressors and reinjection techniques exceed the value of the oil, the compressors will not be added, and it may allow the pressure in the oil field to drop. While the State report used a minimum production rate of 100,000 barrels a day to measure the economic life of the field, this level may be too low to offset the costs of continued reservoir maintenance. For example, field expenses are currently $20 million per year to reinject the gas, with an additional $2.5 billion to $3 billion invested as a one-time expense in the waterflood program. One Interior Department official believes that 150,000 to 200,000 barrels of oil per day is probably as low as the producers will allow the field's production to go. Since production is expected to approach 400,000 barrels per day through 1998, the economics could justify continued reinjection through the 1990's.

Furthermore, continued reinjection will consume a lot of gas as compressor fuel. Approximately 100 million cubic feet of gas are used daily to fuel these compressors.

In addition to its waterflood program, the North Slope producers recently received State approval for an additional recovery program to inject enriched hydrocarbon gas, alternating with water, into a test area of the reservoir. This program is being tested on 2 percent of the Prudhoe Bay field as a means to increase ultimate oil recovery. The producers estimate that an additional 5.5 percent, or 24 million barrels of oil, could be recovered in the test area using this new injection program. It is unclear whether this test program could have broader application in future years.

Field operations will continue to use large amounts of Prudhoe Bay gas

Oil-related operations on the North Slope are energy intensive. The oil must be gathered and purified, and the TAPS pump stations and compressors for gas reinjection fueled. New facilities will add to fuel demand. Since the North Slope gas itself has no market value and the State allows lessors to use the gas for field fuel without charge, the producers are likely to continue using gas to fuel as many operations as possible.

Using the gas for field operations eventually reduces the amount of gas available for transportation or use. Over the next 25 years, field activities can be anticipated to consume a total of about 12.5 percent (3.3 Tcf) of the 26 Tcf of recoverable reserves in the Prudhoe Bay field before export. Delay of a transportation system beyond 1989 would increase the fuel consumed because of the continued need to fuel compressors for reinjection.

FLARING THE GAS WOULD REQUIRE A LEGISLATIVE CHANGE

If prolonged reinjection were likely to harm the Prudhoe Bay oil field, State law would need to be changed before the gas could be flared (vented into the atmosphere). [6] Therefore, the North Slope producers must continue reinjecting the gas until another use can be made of it. In addition, Alaska Oil and Gas Conservation Committee Order No. 145 on the Prudhoe Bay field requires that "Until a large gas sales pipeline is available, all produced gas, except that used as fuel in the field and small local gas sales, will be reinjected into the gas cap."

If prolonged reinjection were likely to harm oil recovery at Prudhoe Bay, the producers could request a change in State law to allow them to flare the gas. If no alternative use for the gas was available at that time, it might be in the State's interest to protect its oil revenues by permitting gas flaring. But this alternative would not be beneficial.

CONVERTING TAPS TO A GAS PIPELINE

A petroleum pipeline and transportation system currently exists in Alaska--the Trans-Alaska Pipeline System. To avoid the costs and problems associated with building a new gas pipeline, it would be technically possible to convert the TAPS oil pipeline to a gas pipeline. However, in our opinion, this alternative may be impractical (1) until Prudhoe Bay oil production is depleted, (2) if one assumes more oil is likely to be discovered on the North Slope, or (3) until a liquids line is built to carry any remaining oil to South Alaska.

Converting TAPS is an alternative that the North Slope producers have considered. Technically, its major disadvantage is that the pressure of the system is likely to be limited to 900 to 1,000 psig, making it a relatively inefficient gas pipeline. Modifications to the pipeline itself would be necessary, including changing some pipe and valves, replacing pumps with compressor stations, and building a different terminal for LNG processing.

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[6]The State of Alaska prohibits wasting or flaring natural gas (A.S. 21.05.020).

In addition, the gas would have to be heated to (1) avoid permafrost problems where TAPS is buried in thawed soils and (2) maintain a temperature similar to the oil. One producer's estimate of the costs of such a conversion is about $12 billion to $13 billion.

In addition to the TAPS conversion, construction of a smaller pipeline designed to carry gas or liquids has been suggested. This line, perhaps buried in the haul road, could carry gas liquids until the oil production reached a level low enough to transfer its output from TAPS to the small pipeline and would allow conversion of TAPS with no loss of oil production. The economics of small-diameter pipelines, however, makes this an expensive undertaking. With the tremendous uncertainty surrounding the marketing of Alaskan gas liquids, this alternative would be difficult to justify until some point in the future.

Finally, if one assumes that additional oil supplies from Duck Island, Point Thompson, Kuparuk, and offshore Alaska will require shipment, it seems unlikely that the producers would be able to phase out the TAPS pipeline, except over the long term.

CHAPTER 7

EVALUATION OF STATE OF ALASKA

REPORTS ON USING NORTH SLOPE GAS

Three reports have been prepared for the State of Alaska evaluating alternative uses for Prudhoe Bay gas. [1] Two of these reports see advantages to construction of an all-Alaskan pipeline system producing LNG for export to Japan. The third deals exclusively with gas for electric power generation within the State. These reports describe the marketing and cost problems any of these systems to transport Alaskan gas will encounter. Our analysis indicates that these problems are likely to undermine the viability of the State's alternative proposals to ANGTS.

BACKGROUND

In June 1982, the Alaska legislature appropriated $500,000 for two studies on the use of North Slope gas. [2] The first $250,000 was appropriated to the Alaska Power Authority for a study to determine the feasibility of using North Slope gas to generate electricity for the State. (APA hired Ebasco Services, Inc., to perform this study.) The remaining $250,000 was appropriated to conduct a feasibility study of a gas pipeline to south Alaska. To accomplish this, the former Governor of Alaska directed a task force of State agency heads and legislators to study all alternatives to get North Slope gas to market. [3] Finally, an eight-member citizens advisory committee, the Governor's Economic Advisory Committee on North Slope gas, was also asked to investigate the economic feasibility and business aspects of the various alternatives. (The appropriation was used by the State Task Force to hire the services of Booz, Allen & Hamilton, Inc., to prepare a report evaluating alternatives; some minor finances were also provided to the Governor's Economic Committee.)

REPORT TO THE GOVERNOR'S TASK FORCE ON NORTH SLOPE NATURAL GAS

Booz, Allen & Hamilton's draft final report analyzes five alternative uses of North Slope gas:

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[1] As our report went to press, only one of these studies had been issued in final form.

[2] See sec. 244 and 245 of the appropriations act of June 29, 1982.

[3] The State of Alaska Task Force on Alternative Uses of North Slope Natural Gas, hereafter referred to as the State Task Force.

--ANGTS.

--A trans-Alaska gas pipeline system (TAGS).

--Methanol (a 5,000 MTPD unit in Fairbanks area).

--Electricity generation in the Fairbanks area.

--Enhanced oil recovery.

The report limited itself to these five alternatives after an earlier analysis (Nov. 1982) indicated that these were the most promising, based on project economics, markets, value added in Alaska, technological risk, and other factors.

Only two of the five alternatives analyzed are full-scale projects using the entire Prudhoe Bay gas stream. The report found that these two projects--ANGTS and TAGS--were able to deliver gas to markets at similar costs. However, TAGS has significant economic advantages over ANGTS--a Japanese market that could absorb higher priced gas than the lower 48 States and the potential for higher wellhead return to the producers than with ANGTS. State tax and royalty returns are also estimated to be higher with TAGS, according to the report.

The relatively short market opening in Japan for Alaskan gas is the major risk associated with TAGS, according to the report. Japan is contracting for its 1990's supplies and has gas suppliers located closer to its ports than Cook Inlet. TAGS will lose this market, according to the report, if it does not become "* * * the viable project" soon. The report further states that if the TAGS project is not operating by the 1988-1990 period, "* * * the market window may be lost until after 2000." [4] The report recognizes, however, a number of key legal and regulatory issues are likely to delay TAGS' approval beyond 1988.

The remaining three alternatives examined by Booz, Allen & Hamilton would use only relatively small portions of the gas. Moreover, two of these--electricity generation and methanol, both located in Fairbanks--were found desirable only if the required gas were tapped from TAGS or ANGTS. According to this report, the temporary use of some gas for enhanced oil recovery could be a viable use of the gas, especially in the period preceding completion of a major pipeline project.

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[4] Booz, Allen & Hamilton, Inc., "Evaluation of Alternatives for Transportation and Utilization of Alaskan North Slope Gas," draft final report, Feb. 1983.

The Booz, Allen & Hamilton report makes the broad recommendation that the State of Alaska should support North Slope gas development by helping to facilitate both ANGTS and TAGS. More analysis of TAGS' costs and economics is required to allow for an adequate, in-depth comparison with ANGTS, however. Therefore, the report also suggests that additional issues should be addressed.

Comparison of State Task Force and our findings

We and the State Task Force contractor used several similar criteria in evaluating alternatives, primarily cost and marketability criteria. The State report also used benefits to the State as a major criterion.

Both reports emphasize the marketability problems facing ANGTS and an all-Alaskan pipeline. The State report explicitly discusses the various impacts of oil prices on gas markets. The State Task Force report recognizes, by including a "flat prices" scenario [5] that the current changes in the oil market may be an indication of a more basic change in long-term oil markets. The most obvious implication of the "flat prices" scenario is lower returns to both TAGS and ANGTS. Under all the price scenarios evaluated by the State's contractor, TAGS yields greater returns to the producers and the State than ANGTS, largely because TAGS' LNG is assumed to be sold to Japan on a Btu oil equivalency basis. Solely on the basis of wellhead return, TAGS looks better than ANGTS, according to the contractor's report, regardless of what oil prices do.

However, the different price scenarios will have different impacts on the market opportunities for each project. The lower oil price scenarios are predicted to hurt the TAGS market in Japan more than ANGTS' market, according to this State report. With slow economic growth and soft energy demand accompanying the lower oil prices, LNG exporters will be vigorously competing to maintain market shares and maximize revenues. On the other hand, in the lower 48 States, gas exploration and production could decrease, providing a potential market opportunity for ANGTS gas. (Conversely, the TAGS market appears safer than lower 48 States markets under a stronger economy/high-price scenario, according to this report.)

The State Task Force report did not specifically state the most important implication of a "flat price" scenario--the possibility that any major North Slope gas project will not be economical without the prospect of rising oil prices. In our

[5]This scenario reflects a 2-percent-per-year real decline in world oil prices to 1988 and no increase in real terms thereafter.

discussions with various financial institutions, we found that, without guaranteed cost recovery, severe financing problems are likely for large-scale energy projects that depend on rising oil prices to be competitive.

The State's report also discusses the economic problems with electric generation or a methanol project if a small-diameter pipeline is built from the North Slope to Fairbanks. We concur in the report's conclusion that a full-scale pipeline project could serve local communities at less cost.

Finally, the enhanced oil recovery analysis in the Booz, Allen & Hamilton report is limited to one ongoing recovery project for existing oil resources at Prudhoe Bay. Our evaluation was broader and concerns both gas reinjection and heavy oil recovery elsewhere on Alaska's North Slope. In either case, enhanced recovery is not seen as a major near-term use for the gas.

FINAL REPORT OF GOVERNOR'S ECONOMIC COMMITTEE ON NORTH SLOPE NATURAL GAS

According to the Governor's Economic Committee on North Slope Natural Gas, TAGS is the best means of transporting North Slope Gas to a market. [6] The report states that TAGS has several important advantages, including

--lower project costs;

--elimination of the need for a separate NGL pipeline;

--greater marketing flexibility;

--possible greater returns to the producers through the use of a "beachhead," as opposed to a wellhead price for the gas; and

--more flexible financing through segmenting components of the system as separate risks.

TAGS would be built in three stages, over a 9-year period, with an initial delivery of 0.65 bcfd of natural gas to Japan at the end of the fifth year. The second and third stages of TAGS, completed in later 2-year increments, could deliver approximately 1.2 bcfd and 1.9 bcfd, respectively, of natural gas to Japan and other markets.

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[6] Governor's Economic Committee on North Slope Natural Gas, "Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas," Jan. 1983.

If the TAGS project were to be built, additional benefits would accrue to both the Nation and Alaska. The committee sees national benefits from TAGS including increased Federal leasing revenues, a decreased balance of trade deficit with Japan, and increased national security, since the Japanese would not have to become reliant on the Soviet Union for energy. State benefits would include increased State revenues and employment, more power available for the areas near TAGS, and the potential for future south Alaskan industrial development to process the gas resources (petrochemicals). However, we believe many of these benefits would occur to the Nation and the State of Alaska from any major Alaskan transportation alternative and cannot be treated as benefits unique to TAGS.

Comparison of Governor's committee and our findings

While the project's advantages and benefits indicate that TAGS is attractive, the committee's report recognizes that the time for marketing LNG in Japan may soon end. The committee's report encourages prompt initiation of TAGS. We believe TAGS, as proposed by the Governor's Economic Committee on North Slope Gas, will confront obstacles to its completion similar to those discussed for an AAPS in chapter 4. Specifically, based on conceptual design, the cost estimates for a TAGS will likely escalate as detailed engineering studies are performed; the marketing of Alaskan LNG in Asian countries cannot be presumed because of slack demand; several jurisdictional questions remain as to the extent of Federal regulation over a TAGS; and financing difficulties could face this system as well.

Cost estimates for TAGS will increase with detailed engineering work

The committee recommends construction of a high-pressure (dense phase) pipeline system that could ultimately transport 2.8 bcfd of raw natural gas from Prudhoe Bay to an LNG plant at Nikiski on the Kenai peninsula. Using our assumptions of inflation and interest rates and the methodology of appendix VIII, TAGS' minimum charge including the wellhead price would be \$6.43 per MmBtu. [7] In all probability, system costs will increase as the conceptual design estimates are refined through engineering studies. For example, the project's delivered price

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[7]The committee's economic advisors determined the pipeline component price to be \$3.48 per MmBtu which, when combined with a \$2.28 per MmBtu wellhead price and a marine transportation charge of \$1.11 (as determined by the committee's marketing advisors), would result in a \$6.87 per MmBtu delivered price to Japan.

to Japan, assuming a per-mile-cost similar to the Alaskan segment of ANGTS, would be higher than the conceptual design estimate.

As displayed in table 9, the total system cost for TAGS would be $14.3 billion in 1982 dollars, or $25.5 billion when the project is completed in 1992. The system's estimated costs of over $14 billion do not include about $4 billion that would be needed for compression facilities on the North Slope and for LNG tankers. According to the committee's engineering advisors, about $1 billion for initial compression was excluded from the system's cost estimate because it was assumed that existing facilities owned by North Slope producers could be used. This cost was included in our AAPS estimate. According to our subcontractor, initial compressors would be needed beyond those owned by the producers to act as a contingency should the pipeline shut down and gas reinjection be needed to maintain the flow of oil through the TAPS line. Since the TAGS system's initial phases would deliver only a portion of the gas being produced, the remaining gas would have to be reinjected, requiring compressor capability and continuing some of the costs of a reinjection program.

Table 9

Trans-Alaska Gas System
Capital Cost Estimates

Components	Base case with contingencies in 1982 dollars	Current year dollars with interest
	(billions)	
Pipeline	$ 8.24	$14.65
Conditioning	1.42	2.52
LNG plant	4.63	8.30
Total	$14.29	$25.47

Source: The Governor's Economic Committee, "Trans Alaska Gas System: Economics of an Alternative for North Slope Gas."

In addition, the TAGS estimate above does not include the cost for LNG tankers used to deliver LNG to foreign and domestic markets. The committee estimates that ships will cost about $175 million each for new construction. If the entire volume of natural gas was delivered to Korea, for example, 19 new LNG tankers would be needed, at a total capital cost of about $3.3 billion. [8]

The committee's cost estimates are based on conceptual design. The increased estimating detail that would accompany an engineering design will, in all likelihood, result in a cost estimate that is higher than the current TAGS estimate. On the basis of previous pipeline project experience, the costs for the system will increase as more data are known on the environmental and technical problems with the system. The Alaskan oil pipeline, for example, was originally estimated to cost slightly more than $1.0 billion. Its final cost of nearly $8 billion was based on more system design and engineering, improved system definition, and actual construction experience. If the estimate for the TAGS pipeline were to reach the ANGTS per mile cost of $13.3 million, the 820-mile TAGS would cost an estimated $17 billion in 1982 dollars, or about $31.7 billion when completed. [9] The detail provided by an engineering study would be needed to further define the costs for an all-Alaskan pipeline system and to determine a possible contract price between the potential sponsors of TAGS and the potential purchasers of Alaskan LNG.

Marketing Alaskan LNG in Asia unlikely

The opportunity for marketing Alaskan LNG in Asia, primarily Japan, is likely to pass during the period that a TAGS seeks to market its LNG abroad. The committee's report concludes that by 1990, Japan will need to import an additional 2 to 9 MMT of LNG. However, the report also shows that Japan will have already contracted for enough supplies by 1990 to meet these needs and, therefore, could have a surplus and need no additional reserves (including those from Alaska). If demand projections change and additional LNG supplies are required by Japan, several countries with LNG export plans that are more advanced than Alaska's could fill the gap.

The committee's marketing advisor, Mitsubishi Research Institute, forecasts that Japan will need 37 MMT of LNG in 1990. As projected by the committee and displayed in table 10, Japan

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[8]Although the committee estimates that component cost for marine transportation to Japan would be $1.11 MmBtu (new LNG ships), the number of ships required and the total ship cost were not provided in the report. The $3.3-billion cost for marine transportation to Korea assumed in the report would probably decrease for the voyage to Japan.

[9]Based on a 5-year compressed construction period and our assumptions on inflation and interest rates. The project's planned construction period is 9 years, but the committee believed the system could be completed in 5 years. The projected cost for TAGS is higher under this scenario.

will have sufficient contracts to meet and exceed this projected demand. (The supply picture includes 2.9 MMT per year from Canada, based on the January 1983 decision of the National Energy Board of Canada to permit LNG exports to Japan.) In addition, the committee states that 3 MMT of LNG from the Soviet Union will be shipped to Japan because of its nature as a Government-level project. A potential LNG surplus of 3.6 MMT could emerge if the Soviet project is completed by 1989 as planned.

Table 10

Japanese LNG in 1990: Supply and Demand

LNG suppliers:	Million metric tons of LNG
Existing sources	
Brunei, Abu Dhabi, and Indonesia	14.7
Scheduled projects	
Indonesia (supplement)	1.5
Malaysia	6.0
Badak, Indonesia	3.2
Irun, Indonesia	3.3
Australia	6.0
Canada (note a)	2.9
Total	[b] 37.6
Mitsubishi demand estimate	37.0
Surplus	.6

[a]Canada has been included as a result of the January 1983 National Energy Board export decision.

[b]Does not include LNG from Alaska's Cook Inlet--about 1 MMT--since current contracts expire in 1989.

Source: The Governor's Economic Committee, "Trans Alaska Gas System: Economics of an Alternative for North Slope Gas," Jan. 1983.

Although the committee's marketing advisor believes the Japanese Government's demand forecast of 43 MMT in 1990 is too high, should demand increase to this level, Japan would need an additional 2.4 MMT per year. [10] As stated in chapter 4 and as noted by the committee, the additional reserves that may be needed could be supplied from projects in Qatar, Thailand, and Indonesia that have a combined per-year production potential of 14 to 15 MMT. These countries developed natural gas export plans in response to a perceived demand in Japan and, according to the committee, have at least 2 years lead time in approaching the market.

Thus, the timing of an Alaskan LNG project is critical for its sponsors. The committee's report states that phase I of TAGS could be completed in 1988--in time to displace the Soviet Union gas scheduled for 1989 delivery, even though the committee considers this a firmly committed project. In addition, if markets demand more gas, the entire project could be accelerated and completed in 5 years. (The State Task Force's report, on the other hand, has concluded that TAGS completion could well be delayed beyond 1988.)

Regulatory questions remain over TAGS designation as a gathering line

Exporting Alaskan LNG to Japan must comply with the statutory restrictions discussed in chapter 4, including a requirement for Presidential approval. The sponsors of TAGS also propose the shipment of LNG to the U.S. West Coast after the entire system is built. Such a system would be subject to FERC jurisdiction under the Natural Gas Act. (See ch. 4.)

The committee recognizes that TAGS would have to comply with export control statutes before it could export LNG to Japan. Furthermore, its legal advisors believe the export provisions of ANGTA, for example, could be met. With respect to shipping LNG to California, the committee's legal advisors assert that FERC jurisdiction over TAGS could be limited by having the system classified as a gathering line carrying the gas from the well to its processing point. The gathering of natural gas is excluded from FERC's jurisdiction under the Natural Gas Act by section 1(b) (15 U.S.C. 717(b)).

The committee argues that TAGS, which carries carbon dioxide-laden gas to south Alaska, where it would be cleaned, "* * * might be considered part of a sophisticated gathering

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[10]Demand would equal 43 MMT. Supply would equal 40.6 MMT, including natural gas from Canada and the Soviet Union.

system necessitated by the unique transportation barriers imposed by the Alaskan environment and patterns of land ownership." This interpretation depends to a large extent on whether FERC would consider the gas at south Alaska to be in an unconditioned form. According to FERC officials, the gas may be considered conditioned if, for example, water is removed at Prudhoe Bay or if the gas is changed in any way, such as compression or chilling, to make it suitable for pipeline transmission.

In addition to the issues involved in obtaining a gathering line classification, another consideration for TAGS sponsors would be the timing of their application. If the sponsors of TAGS wait until after the pipeline is constructed and wish to ship LNG to the West Coast, they run the risk that FERC might not certify the system as already constructed. This is an important consideration for TAGS since the committee proposes initial deliveries of LNG to Japan, which would not involve FERC, and subsequent deliveries of LNG to the West Coast, which would involve FERC.

TAGS will face financing problems

The large capital costs required to construct TAGS will impose a major financing obligation on potential sponsors. The committee cites several potential equity sponsors for the project and possible lending sources from Japanese banks. The committee's report emphasizes the component nature of TAGS--pipeline, conditioning facilities, and LNG plant--as a means to provide financing options to the project.

For the equity portion of the project, the committee notes that its potential sponsors include the North Slope producers, the State of Alaska, the gas users (e.g., Japanese utilities), the Japanese Government, and major contractors and suppliers. (These are the same potential sponsors as those of ANGTS, except for the Japanese Government.) These potential investors could own and operate, either separately or collectively, the three discrete components of the TAGS, according to the committee. For example, the State of Alaska or Japanese trading companies could own the Cook Inlet LNG plant. The committee views such component financing as a way to facilitate the entire project's financing. However, the committee does recognize that component financing is subject to the limitation that all components must be financed on a basis that ensures the timely completion of the entire system.

Our discussions with major U.S. banks indicate that their approach to financing TAGS would not change--either the companies involved or the Japanese Government must cover the project's risks and guarantee completion of the system's construction. Any such project must prove its technical feasibility and economic viability through adequate credit support and completion guarantees, according to these bankers.

The committee does not discuss debt financing in detail but does note three Japanese lending institutions that could be used: Japan National Oil Corporation, Export Import Bank of Japan, and the Development Bank of Japan. (The expenditures of these three institutions in 1981-82 were about $2.4 billion.) However, TAGS may not have access to these funds. The recent problems experienced by the Australian LNG project exemplify the potential obstacle for TAGS.

Information obtained from a major Japanese trading company indicates that the Australian LNG project may be delayed because an important loan from Japanese banks may be disapproved. Several reasons were cited for this possible refusal. First, the Japanese LNG purchasers have observed a definite Japanese policy that they should not be involved in the financing of LNG projects, i.e., financing should be the gas suppliers' responsibility. Second, the borrowers of direct loans should be (1) in a developing country and (2) a government or a governmental body. As a result of these loan conditions, the Australian LNG project faces financing uncertainties. If the proposed TAGS seeks debt financing under similar conditions from Japanese institutions, it may confront similar problems.

Finally, the committee suggests that the State of Alaska may be able to participate in TAGS financing through the issuance of tax-exempt revenue bonds for the LNG facilities. The States' participation would contribute to the economics of the project by providing new sources of capital, reducing equity investment in the LNG plant, and reducing the cost of debt financing, according to the committee's report.

However, the committee notes the State may not be able to implement tax-exempt financing since it depends upon future interpretations or modifications of the tax laws. We agree that the Internal Revenue Code would preclude the use of tax-exempt financing of the liquefaction plant and would apply only to certain infrastructure such as docks, wharves, and storage facilities (a small part of the project's expense). As discussed in chapter 3, the State of Alaska would need to approach the Congress for a change in the law specifically for TAGS, in order to realize some of the tariff savings shown in the committee's report for tax-exempt financing.

REPORT TO THE ALASKA POWER AUTHORITY ON USING NORTH SLOPE GAS FOR HEAT AND ELECTRICITY

The draft report of Ebasco Service, Inc., for the Alaska Power Authority evaluates three scenarios for power use: generating electricity on the North Slope, at Fairbanks, or on the Kenai Peninsula. (Costs for each of these alternatives are projected using two demand forecasts.)

--The Fairbanks scenario is the most expensive ($4.7 billion to $6.2 billion) because it includes a small-diameter pipeline and a North Slope gas conditioning facility as well as upgraded power lines from Fairbanks to Anchorage. In addition, over $1 billion for a gas distribution system to serve residential and other customers in Fairbanks would be required.

--Transmission from the North Slope ($3.3 billion to $4.2 billion) includes the cost of high-power lines from the North Slope to Fairbanks and upgrading of the Fairbanks-Anchorage intertie.

--Kenai Peninsula power use is seen as the most economic, at a cost of about $2 billion. This scenario assumes that the costs of a major gas pipeline system from the North Slope to South Alaska (TAGS) would be borne by other investors.

The Ebasco report does not recommend any of these three systems. Rather, the report states that because each scenario is different, "* * * cost comparisons should not be the sole factor in evaluating the desirability * * *" of any of them. While socioeconomic and environmental effects of these major electric power projects are substantial, the report believes they can be mitigated.

<u>Comparison of Ebasco and our findings</u>

The Ebasco draft study evaluates alternatives which, at most, could consume about 204 bcf per year by 2010, or 21 percent of the annual production of Prudhoe Bay gas. Given the levels of investment required to construct any of these systems, it is difficult to see how any of the projects could be economically viable because of the high per-unit cost that would likely result for the small amount of gas consumed. For example, Ebasco estimates that a 1,260 psig, 22-inch diameter pipeline to Fairbanks could cost about $4.8 billion. This is about 48 percent of the cost of the 743-mile Alaskan pipeline segment of ANGTS. When the additional costs for gas conditioning, distribution, and upgrading of the transmission intertie to Anchorage are included, such a project could cost approximately $6.7 billion to construct, according to Ebasco. Such an investment, however, would only serve and be paid for by Alaska's small population. If the State were willing to support such a large expenditure, many of the same benefits could be obtained from financial assistance to one of the major pipeline projects.

Ebasco's report also discounts the advantages of moving the gas to south Alaska for power by stating that "* * * the waste gas stream associated with the Kenai generating scenario is incapable of meeting the needs of even the low forecast * * *" for

State power use.[11] Only 50 percent of the required energy for the power plant could be provided from the TAGS system's waste gas. Therefore, additional gas that might have been targeted for LNG production would have to be made available to such a power project. By reducing the volume of gas available for sale as LNG, the higher netbacks assumed in the two other State reports for a trans-Alaska gas pipeline would be offset somewhat (unless the gas sold for electricity were priced competitively with LNG). Moreover, as previously discussed in chapter 6, other gas producers in the Cook Inlet area would have an opportunity to market their gas in Japan. They could increase their prices to local consumers and still keep their gas competitive with North Slope gas. Therefore, consumers would likely bear the cost of higher priced gas-generated electricity under these projects to bring North Slope gas to South Alaska.

[11] Ebasco Services, Inc., "Use of North Slope Gas for Heat and Electricity in the Railbelt," draft final report, Jan. 1983.

CHAPTER 8

CONCLUSIONS

Our examination of a variety of alternatives for bringing North Slope gas to market shows that there is no easy solution to the issue. Marketability and financing problems which have hindered the ANGTS project are likely to affect other options for transporting all the Prudhoe Bay gas. Processing the gas for export as methanol or petrochemicals faces marketing and other problems as well. Using the gas within the State of Alaska will not consume large quantities since State demand is small (less than one-fourth of the gas) when compared with the 26 Tcf of Prudhoe Bay gas reserves and estimates of possible future discoveries.

It should be remembered that the ultimate disposition of Prudhoe Bay gas is in the control of the North Slope producers. Neither the U.S. Government nor the State of Alaska can require that any action be taken to use the gas unless the producers first determine that it is in their interests to do so.

CLEAR MARKET SIGNALS WILL BE NEEDED BEFORE ANGTS IS COMPLETED

The ANGTS project faces a lower 48 States gas market that is dramatically changed from the situation projected in 1977, when the project was approved. Declining oil prices and continuing gas surpluses in the lower 48 States could continue to delay ANGTS. The project's timing will depend on whether a clear need for Alaskan gas in 1989 or beyond can be demonstrated.

Because of ANGTS' high construction costs, the delivered price of its gas, especially in the project's initial years, is expensive and will be competing with lower average gas prices, nationwide. This has led to consideration of changing the project's tariff to reduce the price of the gas in its early years and provide relatively level gas prices over the life of ANGTS.

Levelizing the ANGTS tariff will require restructuring the risks of the project by deferring returns to investors and possibly lenders. While tariff levelizing may be needed to make the gas marketable, it complicates the financing requirements for the project.

ANGTS HAS PROBLEMS WITH PRIVATE SECTOR FINANCING AS REQUIRED BY THE 1977 PRESIDENTIAL DECISION

Once the marketability problem is resolved, the ANGTS project faces further delays because of its financing problems. We have defined these problems as a credit support gap, a capital gap, and a refinancing gap. The Canadian, as well as Alaskan, segments of the project face financing uncertainty.

Credit support gap

The ANGTS system will not be financed until banks and other potential lenders are convinced that adequate collateral is provided to cover the project's debt if construction of the Alaskan segment is not finished. To date, neither the sponsors nor the producers have offered sufficient credit support to guarantee completion of the pipeline's construction. Each participant has set specific limits on the amount to be pledged to ANGTS. As a result, the combined contributions of the participants fall at least $5 billion short of the total funds likely to be required as credit support.

Capital gap

Even if sufficient credit support were provided for the Alaskan segment, whether sufficient capital will be available to build the pipeline is uncertain. In 1981, ANGTS' bank advisors estimated that between $12 billion and $18 billion might be available from world capital markets to finance the project's Alaskan facilities. This assessment was based on optimistic assumptions about the participation of U.S. and world banks as well as institutional lenders. Our review suggests that if another capital study was done today, the amount likely to be available to ANGTS would be lower.

Refinancing gap

The life of the ANGTS project is usually assumed to be 25 years. Returns to investors come in the later years of the project's operations and could be delayed by levelizing the tariff and stretching out debt repayment. While ANGTS will recover its costs over 20 to 25 years, loans available to the project will be of a shorter term nature--an average life of probably 7 to 8 years. It is unlikely ANGTS will be able to attract initial financing at terms to match its payback period.

Therefore, ANGTS will face refinancing requirements in its early years of operation. As with other large utility projects, this refinancing issue must be addressed before financing is provided for construction. The project must be operational and the gas marketable enough to attract additional investors to refinance maturing loans.

Canadian segment financing problems

Financing problems are not largely unique to the project's Alaskan facilities. The Canadian segment, as well, faces problems with the adequacy of its credit support and the availability of capital to finance its construction at the same time that the Alaskan facilities are being financed. The costs of the Canadian segment currently exceed the capital likely to be available within Canada. Both segments will be seeking substantial foreign financing.

ANGTS WILL REQUIRE SPECIAL FINANCIAL ARRANGEMENTS

Most proposed solutions to ANGTS' financing problems fall short, by themselves, of meeting the necessary requirements for financing. For example, levelizing the tariff, which would require major concessions on returns to producers and sponsors, does not guarantee sufficient credit support. Increasing participants' contributions to ANGTS to cover the needed credit support would not necessarily attract the major amounts of capital needed to build the system. Bringing the State of Alaska in as a participant will not by itself provide sufficient revenue to guarantee the project's completion. A combination of special financing arrangements is likely to be needed to construct the system.

Our discussions with the banking community indicate that only two entities have sufficient finances to guarantee ANGTS' completion--Exxon or the U.S. Government. Exxon has time and again refused to act as a guarantor for the project. And as only a one-third gas owner, is it reasonable to assume Exxon should? Moreover, even if it were to undertake that responsibility, ANGTS' initial funding would still have to come from private capital markets--markets that we believe could be stretched for this investment. U.S. Government involvement, on the other hand, would open up public debt markets and make additional capital available to the project.

Most ANGTS participants, as well as members of the financial community, now believe that some form of Federal involvement will be necessary to ensure the project's completion. The best form of Federal assistance is unclear, however, and is likely to require further study by ANGTS' participants before they decide how to seek Federal financial assistance.

AN ALL-ALASKAN GAS PIPELINE MUST OVERCOME SEVERAL OBSTACLES

Construction and operation of an all-Alaskan gas pipeline system depends on the resolution of several obstacles that undermine its viability. First, Japan is not likely to be a market for Alaskan LNG. Several other countries with existing infrastructure or firm plans to construct facilities for LNG exports are similarly targeting Japan as their eventual purchaser of LNG; market opportunities in Japan are limited especially because of slack Japanese LNG demand. An AAPS must also obtain certain Presidential determinations to overcome the statutory limits placed on the export of North Slope natural gas to countries outside of North America. Designers of AAPS must overcome engineering and environmental problems associated with a chilled pipeline buried through seismically active areas of Alaska and below the waters of Cook Inlet.

Both the Governor of Alaska's Economic Committee and a recent report prepared for the Maritime Administration favor this transportation alternative to serve Pacific Rim markets. However, the attractiveness of an all-Alaskan pipeline system is based on speculative cost estimates. Further design and engineering work could increase these costs and thereby reduce any advantages for an LNG alternative. Moreover, the capital required to finance the estimated costs of the project is large and the project could face the same financing difficulties as ANGTS if sponsorship is not sufficient to guarantee completion of the system.

Whether the United States is willing to export gas becomes critical to the viability of an all-Alaskan pipeline. Because of legal limits on gas exports under ANGTA, the President would first need to make a finding that gas exports are in the national interest. Such a finding is likely to involve difficult political choices for both the administration and the Congress.

MARKETING DIFFICULTIES MAKE METHANOL AND PETROCHEMICAL ALTERNATIVES UNVIABLE AT THIS TIME

While an Alaskan methanol project to use all the gas might be built for slightly less than the cost of the entire ANGTS system, this alternative would deliver only about 60 percent of the energy (Btu's) of ANGTS. Its methanol would also be more costly than methanol from other sources.

Alaskan methanol would face the additional problem of a limited methanol market in the United States. While new methanol uses may well develop in the future, expensive Alaskan methanol is unlikely to promote this development. Our consultant's analysis shows a wide range of delivered methanol prices, most of which would be unlikely to find a market. A variety of technical and contractual uncertainties also need to be resolved before an Alaskan methanol project could be considered an economic venture.

The petrochemical industry is undergoing a period of structural change requiring the industry to adapt to low growth and a supply surplus which is anticipated to last throughout the decade. Petrochemical producers are examining potential sites very closely to decide where a limited number of new plants should be located. They are negotiating with interested governments to achieve the most favorable project conditions. Foreign countries offer the petrochemical industry significant incentives to maintain production in their countries.

A competitive Alaskan petrochemical project would require that someone match the terms that other governments have offered and offset the disadvantages of remote location, higher operating costs, and high feedstock costs attributed to an Alaskan project. These required subsidies, combined with anticipated low profits for an Alaskan project, make a major petrochemical project in Alaska an unattractive venture.

CONTINUING TO REINJECT GAS MAY BE THE ONLY ECONOMIC CHOICE FOR THE NEAR TERM

Using the Prudhoe Bay gas within the State of Alaska would not be attractive to the North Slope producers because their returns for such limited gas use would be small. In addition, major pipeline projects which use all the gas are considered a way to use the gas within Alaska as well as share it with U.S. or foreign consumers. Full-scale projects are the only alternatives likely to maximize North Slope gas usage.

Given the current gas surplus in the United States and uncertainties surrounding foreign LNG markets as well as future methanol and petrochemical markets, the only economic choice to use North Slope gas may be continuing to reinject it until market conditions change. Gas reinjection can continue indefinitely according to State of Alaska reports. Any project to bring North Slope gas to market while uncertainties still exist about future gas demand, deregulated gas prices, and future oil prices is likely to meet skepticism from the financial community about whether a need for Alaskan gas truly exists. Given this uncertainty, it appears unlikely that private investors will be willing to lend money today at the levels necessary to construct a major natural gas transportation project.

Moreover, as long as the ANGTS participants continue to pursue the project, there will be legal and political barriers confronting any alternative.

STATE OF ALASKA EVALUATIONS OF ALTERNATIVES

The reports prepared for the Governor and legislature of the State of Alaska emphasize benefits to the State from alternative gas projects. A close reading of these studies indicates that marketing and financing difficulties would confront these alternatives. While it is in the State's interest to see that North Slope gas is developed, the North Slope producers ultimately control its development. The State can either limit or expedite their efforts, but the law to date, which is still supported by the President and the Congress, authorizes only one project to deliver North Slope gas.

FRAMEWORK FOR SELECTING ANY ALTERNATIVE PROJECT

Our analysis of options to use or transport North Slope natural gas indicates that many of the proposals have similar disadvantages largely due to (1) the expense and size of a project needed to move the gas more than 800 miles over difficult terrain to a market and (2) market difficulties. Any major project to move North Slope gas should meet certain conditions if it hopes to be economically viable and acceptable to the financial community:

--The product must have a firm long-term market and a price that minimizes the use of subsidies or assistance to maintain its competitiveness without distorting the market.

--The economics of the project must be attractive, and its financial backers must be strong enough to be able to attract necessary funding. Specifically, the project must be able to assure an adequate return to lenders throughout its entire life, and the project's sponsors must guarantee completion of its construction.

Once these conditions are met, the regulatory system or the Congress, through some mechanism similar to ANGTA, must then create an atmosphere of institutional support and certainty which will allow the project to proceed in a timely manner.

INDUSTRY COMMENTS AND OUR EVALUATION

Sections of our report discussing the ANGTS project were reviewed by officials of the Northwest Alaskan Pipeline Company. (See app. XIII.) A summary of their comments and our response follows.

Northwest's comments emphasize that national security considerations played a major role in the selection of the ANGTS project. Over the long-term, Northwest believes that Alaskan gas will be needed to ensure U.S. energy self sufficiency and meet the gas needs of the lower 48 States.

While we recognize that the uncertainties in current U.S. gas markets could be temporary, our report does not attempt to define when Alaskan gas will be critical to meet U.S. needs. Such forecasting would be highly speculative on our part. Moreover, as outlined in chapter 1 and recognized by Northwest's comments, national security considerations, while important, were beyond the scope of this analysis.

Northwest believes our discussion of ANGTS' financing problems was overly influenced by current market conditions.

Our discussion of financing is caveated to recognize that improved markets and economic conditions could moderate the opinions of the financial community. We maintain, however, that meeting the assumptions of the bankers' 1981 study to finance ANGTS will be difficult. The "extreme conservatism," according to Northwest, in its advisors' estimates still would require a major commitment on the part of the U.S. banking community. As the study itself notes, it would be unwise to maintain that 300 banks at very high levels of their lending limits would finance ANGTS,

> "* * * it is considered unlikely that banks ranking lower than no. 150 will participate as lenders to the project. Similarly, it is likely that the smaller the bank the lower will be the percentage of its legal lending limit committed to the project and the higher will be the likelihood of that bank declining to participate. Realistically, therefore, the project is looking to <u>no more than</u> the top 100 banks * * *." [Emphasis added.] [1]

Northwest disagrees with our characterization of the roll-in cushion for Alaskan gas and the role of State Public Utility Commissions as "issues" surrounding the marketability of ANGTS' gas. Its objections have been noted where appropriate in chapter 2.

Finally, Northwest asks that the reader recognize the caveats attached to our projections of 1990 gas prices from a February 1983 report. We agree with Northwest that all projections of future gas prices or demand are highly dependent upon assumptions. Our February 3 report shows the sensitivity of our results to changes in assumptions regarding both crude oil prices and economic growth. As noted in the report, most of the difference between DOE's or the American Gas Association's results and ours are due to different assumptions regarding future oil prices and the ratio of crude oil to residual oil prices.

We maintain that the forecasts in our previous report are reasonable and based on a sound analysis of the natural gas industry. Our model has been validated by energy consultants and experts at CRS. Rather than being based entirely on econometric modeling, our demand model draws from information obtained through extensive interviews with nearly 200 large natural gas consumers.

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[1] "Alaska Natural Gas Transportation System," (Part 1), 1981: Joint Hearings on H.J. 341 Before the Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce and the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs, 97th Cong., 1st Sess. (1981).

We would like to comment on several of the points made by Northwest regarding our results. First, our report's projected increase in both wood and coal use is consistent with those assumed by Data Resources, Inc., and other industry experts. Second, regarding latent industrial demand for natural gas in 1981, our survey of 80 large industrial gas users and 55 gas distributors found no evidence that natural gas demand was held back by a lack of supply. Northwest argues that this sluggish demand was due to the existing regulatory environment. In reality, however, the existing regulatory environment actually provided a substantial pricing incentive in favor of natural gas, and yet no evidence of latent demand exists. After 1985, when these incentives are removed, natural gas prices, as shown in our earlier report, will be set through direct competition with residual fuel oil. Third, regarding the "significant inconsistency" which Northwest feels exists between our projections of low industrial demand and the conclusion that the gas market will clear at an average wellhead price of approximately 50 percent of crude oil, our findings are totally consistent with both economic theory and results reported by the American Gas Association, Data Resources, Inc., and DOE. All three see natural gas markets clearing at between 50 to 60 percent of crude oil prices. Northwest's logic would have the price of natural gas actually rising in the face of falling industrial demand. In the long term, natural gas must compete on the margin with residual fuel oil, not higher priced fuel oil.

TED STEVENS
ALASKA

United States Senate

OFFICE OF
THE ASSISTANT MAJORITY LEADER
WASHINGTON, D.C. 20510

June 30, 1982

Charles A. Bowsher, Comptroller
United States General Accounting
Office
441 G Street, N.W.
Washington, D.C. 20548

Dear Mr. Bowsher:

I am writing to formally request that your office look into a matter of great National concern, as well as a critical issue for development of Arctic oil and gas resources. The problem concerns the proposed Alaska Natural Gas Transportation System, created in 1976 to deliver the 26 trillion cubic feet of gas known to exist in Prudhoe Bay.

Even though this huge supply of gas has been evident since 1968, we are still waiting today for a transportation system. Pursuant to the Congressional effort in 1976 and subsequent executive and Congressional actions, we are today poised to initiate construction of a route through Canada and into the lower 48.

At this time, the sponsors of the proposed Trans-Canada route are seeking financing for this project. However, there is some doubt regarding the ability of the companies to obtain private financing despite unprecedented capital commitments and passage of a "waiver package" by Congress last year designed to clear the way for adequate private investment.

The problems with financing of the project lead to speculation on the possibility of an alternative delivery system for North Slope gas. The State of Alaska, as a prospective investor in the project and as owner of a royalty interest in the gas, have commissioned a private and governmental task force to analyze the legal, economic, and technical potential for alternatives.

It is my desire that GAO do an independent analysis of this issue. We have seen no evidence that another economic system currently exists to deliver this gas. However, I believe it is time that the Federal government pull together

Charles A. Bowsher, Comptroller
June 30, 1982
Page Two

the vast data on this project and provide a thorough examination of alternatives. I suggest you analyze:

1. The possibility of an "all America" route through Alaska for conversion into liquified natural gas (LNG) for domestic use or exportation,

2. The possibility of using this gas to create methanol for delivery in the lower 48 or abroad,

3. Use of petrochemicals within the state or outside as separate commodities from the natural gas,

4. Use of the gas within Alaska for power generation or other required fuel supplies, and

5. Use of the gas for recovery of "West Sack" petroleum. This resource is a heavy oil geologic formation that exists in the ugnu zone overlapping the Kuparuk field in Alaska. This formation covers an area between 200 to 600 square miles containing 18 to 40 billion barrels of oil. Gas could possibly be used for recovery of this petroleum.

These are some of the areas that should be explored. I feel that a report from you in January or February of 1983 could greatly contribute to any resolution that Congress may have regarding delivery of existing and future North Slope Gas supplies. Thank you for your consideration of this matter.

With best wishes,

Cordially,

Ted Stevens

TED STEVENS
Assistant Majority Leader

I know this will be an expensive project - if you wish to discuss it, I will be pleased to do so at your convenience.

FEDERAL ACTION AFFECTING AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM (ANGTS)

THE ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976

In 1976, the Alaska Natural Gas Transportation Act (ANGTA) (15 U.S.C. 719) was enacted to expedite construction of a system for transporting Alaskan natural gas to the lower 48 States. The underlying reasons for expediting such a project were (1) the existing natural gas supply shortage in the United States, and its anticipated continuance; (2) the large quantity of Alaskan natural gas reserves, which could help alleviate the existing supply shortage; and (3) the national interest.

Because of the magnitude and international ramifications of creating an Alaskan natural gas transportation system, the act marked a major departure from the usual administrative and public participation processes used for selecting and approving proposed natural gas pipeline systems. That is, the act provided for participation by the President and the Congress in the final decision, and it provided measures to expedite construction of the transportation system and delivery of the gas. To help do this, the act limited the jurisdiction of the courts to review the actions of Federal agencies, limited administrative procedures relating to such actions, and limited the Federal Energy Regulatory Commission's authority to select a transportation system for Alaskan gas. The act, however, did not address the possible failure of the project designated by the President and approved by the Congress.

THE PRESIDENT'S DECISION AND REPORT TO THE CONGRESS ON ANGTS

In accordance with ANGTA, the Federal Power Commission (FPC) issued its report to the President in May 1977 recommending an overland system through Canada for delivering Alaskan natural gas to the lower 48 States. Although FPC recommended an overland system through Canada, the Commissioners were split between two of the three applicants for a certificate of public convenience--i.e., the Alaska Arctic Gas Pipeline Company and the Alcan Pipeline Company. (The third applicant, El Paso Alaska Company, proposed an all-Alaskan pipeline and LNG tanker route.) FPC stated that it was premature at the time for the Commission to unconditionally recommend a route since the Canadian Government had yet to decide on the availability of a land route.

The Canadian National Energy Board subsequently approved the Alcan pipeline route and rejected the Arctic Gas route as environmentally unsuitable. At the conclusion of negotiations with Canada, President Carter, on September 22, 1977, announced that he had selected the Alcan Pipeline Project.

In his report to the Congress, the President described the designated project and sponsors, and the pipeline's route and facilities. In November 1977, the Congress, by joint resolution, adopted the President's decision, which included analyses of the desirability, financing, environmental and safety features, reliability, and flexibility of the proposed system and its route. The President's decision included six general areas of terms and conditions which relate to ANGTS:

--Construction costs and schedule management and organization requirements.

--Safety and design requirements.

--Environmental protection.

--Provision of private financing for the project.

--Antitrust requirements.

--FERC certification of facilities.

U.S./CANADA PIPELINE AGREEMENTS

The U.S./Canada Agreement on Transit Pipelines

This agreement between the United States and Canada, signed in January 1977, established the principles of uninterrupted transmission and nondiscrimination for transportation of hydrocarbons (e.g., oil, gas, coal, and their products) between the two countries. The agreement stated that no import or export fees would be imposed on such hydrocarbons. Public authorities in both countries are not to interfere with hydrocarbons in transit and are to facilitate issuance of any permits required for export or import of hydrocarbons between the two countries.

The U.S./Canada Agreement on Principles Applicable to a Northern Natural Gas Pipeline

This agreement sets forth principles for the construction and operation of ANGTS. In the September 1977 agreement, the Canadian and U.S. Governments agreed that a pipeline was the best way to transport Alaskan natural gas to the continental United States. The governments further agreed to take certain steps to facilitate and expedite construction of the pipeline.

The agreement does not discuss alternative forms of transportation. There is no indication that either government considered that a particular pipeline project might fail and that some alternate transportation system might be necessary.

THE NATURAL GAS POLICY ACT'S PROVISIONS FOR PRICING PRUDHOE BAY GAS

In October 1978, the Congress enacted the Natural Gas Policy Act (NGPA) (P.L. 95-621). Section 109 of the act establishes a maximum wellhead pricing policy for particular categories of natural gas, including natural gas produced from the Prudhoe Bay unit of Alaska that is transported through ANGTS. The maximum price for Prudhoe Bay gas is based on a base price of $1.45 per million Btu's (as of April 1977) and adjusted monthly thereafter for inflation. The act also provides for rolled-in pricing (sec. 208), as opposed to incremental pricing, for any gas produced by the Prudhoe Bay unit and transported through ANGTS.

According to the House Conference report, [1]

> "* * * the conferees agreed to provide rolled in pricing for natural gas transported through the ANGTS and for the cost of transportation because they believed that private financing of the pipeline would not be available otherwise."

The conference report also states that "* * * rolled in pricing is the only Federal subsidy, of any type, direct or indirect, to be provided for the pipeline."

THE WAIVER PACKAGE

In October 1981, President Reagan proposed a waiver of law under Section 8(g) of ANGTA [2] to further expedite ANGTS' construction and initial operation by removing "* * * government obstacles to proceeding with private financing." The Congress

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[1]House Report No. 95-1752.

[2]Section 8(g) requires that only the President can propose changes in the law if he finds such changes necessary to "permit expeditious construction and initial operation" of the pipeline.

enacted the waiver of law in December 1981 as proposed by the President, thus granting ANGTS waivers of provisions in the 1977 Presidential decision, the Natural Gas Act, and the Energy Policy and Conservation Act. The waiver package included provisions:

1. To permit the North Slope natural gas producers to own an equity interest in the pipeline and the conditioning plant. (The President's decision had prohibited any equity ownership in the pipeline by these producers. The waiver allows such ownership, subject to approval by FERC and the Attorney General.)

2. To include the gas conditioning plant in the system so that it would be part of FERC's final certificate and subject to most of the provisions in the President's decision.

3. To allow FERC to approve a tariff that will, under limited conditions, permit commencement of partial billing to consumers prior to the flow of Alaskan gas through the pipeline. The provisions also allow FERC to establish a tariff that will provide an assured source of revenue for payment of a minimum bill tariff when the system goes into operation.

4. To eliminate the Natural Gas Act's requirement for FERC evidentiary hearings on each application for a certificate of public convenience and necessity to construct or operate any segment of the system.

5. To prohibit FERC from exercising its authority under the Natural Gas Act to change any final tariff applicable to ANGTS that would impair cost recovery. Specifically, the waiver precludes FERC from changing a tariff which would impair the recovery of actual operation and maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt.

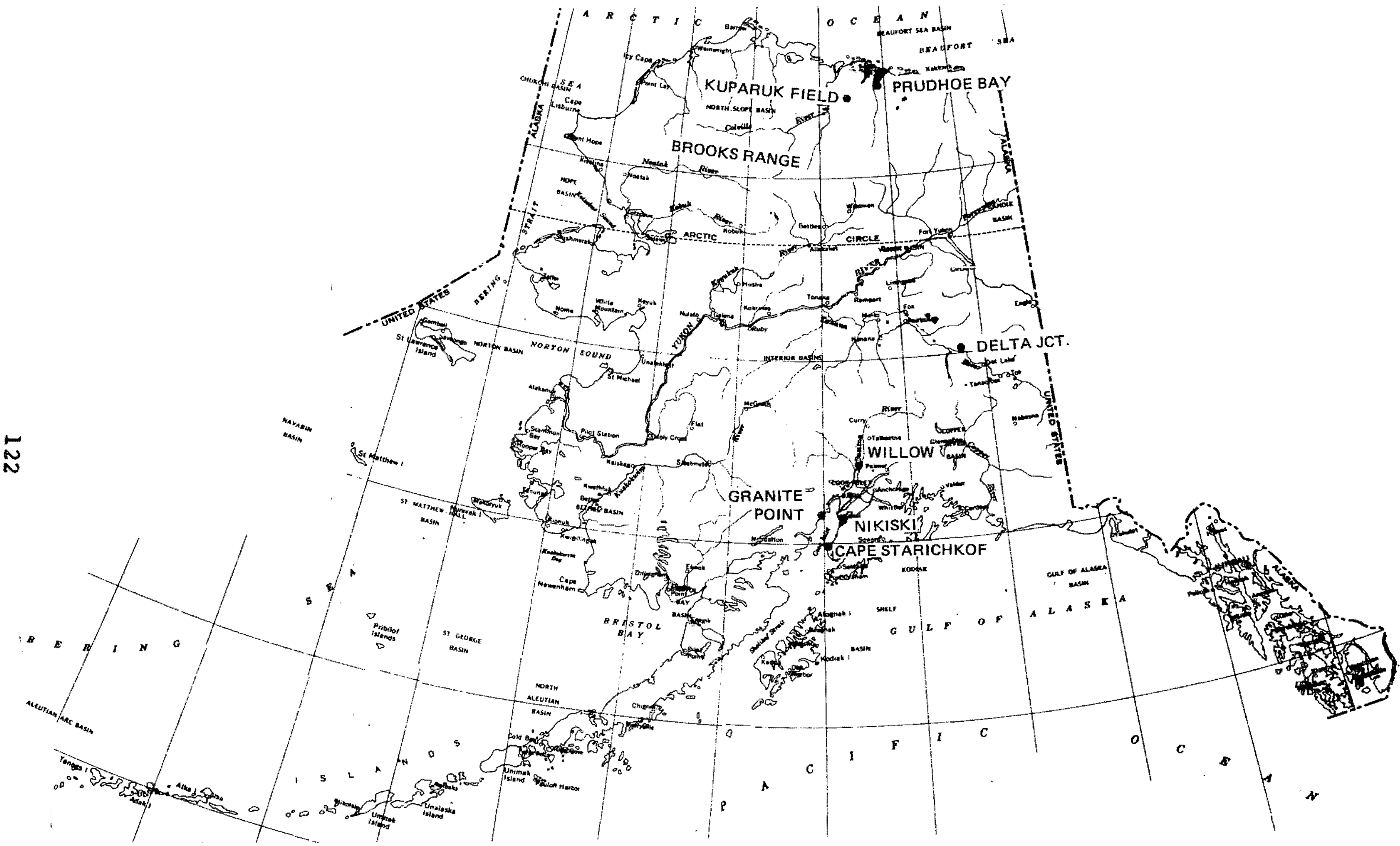
(Legislation has been introduced in the 98th Congress to have the waiver law expire on December 15, 1983, unless FERC has issued a final certificate to ANGTS. See H.J. Res. 192.)

THE TAX EQUITY AND FISCAL RESPONSIBILITY ACT OF 1982

Section 207 of the Tax Equity and Fiscal Responsibility Act of 1982 (P.L. 97-248) amends the Internal Revenue Code to disallow the deduction of interest and taxes (except income taxes) incurred during the construction of real property. Instead, interest and tax costs are to be added to the capital value of the property under construction, and recovered in later years through depreciation.

The act states that this amendment is not to apply to the construction of ANGTS and its related facilities. The effect of this tax provision for ANGTS is a timing difference which permits ANGTS owners to immediately receive the Federal income tax savings arising from the deduction of interest and taxes rather than defer them to the years in which the project is in operation. In future years, as the system goes into operation, Federal tax liabilities for ANGTS may be higher due to lower depreciation charges resulting from expensing rather than capitalizing interest and tax costs incurred during construction. (This, of course, assumes that the project is profitable and that future tax liabilities are not offset by new tax-timing differences.) This provision was intended to help reduce the difficulty of obtaining adequate financing for construction of the project.

MAP OF ALASKA



SOURCE: OFFICE OF THE GOVERNOR, STATE OF ALASKA

APPENDIX III

OIL COMPANY AND GAS

PIPELINE COMPANY CONTACTS

OCS Sale 71 lease bidders contacted:

- Amoco Oil Company
- Chevron U.S.A., Inc.
- Getty Oil Company
- Gulf Oil Corporation
- Marathon Oil Company
- Mobil Oil Corporation
- Phillips Petroleum Company
- Shell Oil Company
- Tenneco, Inc.
- Texaco, Inc.
- Union Oil Company of California

Major gas pipeline companies contacted:

- Colorado Interstate Corporation
- Consolidated Gas Supply Corporation
- El Paso Natural Gas Company
- Great Lakes Gas Transmission Company
- Michigan-Wisconsin Pipeline Company [a]
- Natural Gas Pipeline Company of America
- Southern Natural Gas Company
- Tenneco, Inc.
- Texas Gas Transmission Corporation [a]
- Transcontinental Gas Pipeline Corporation

[a]Former members of ANGTS.

ASSUMPTIONS USED BY GAO CONSULTANTS ON ALTERNATIVES TO ANGTS [1]

(1) No alternative would be started before 1985. Therefore, assume 1985 start date.

(2) No Government financing.

(3) To project base-cost estimates to current year dollars and for all financing work, the following rates are used:

United States

Year	Inflation (GNP price deflator)	Interest rates (nominal) (note a)	Real interest rates
1983	6.6	15.2	8.6
1984	6.5	13.8	7.3
1985	6.6	12.1	5.5
1986	6.9	12.4	5.5
1987	6.8	11.7	4.9
1988	6.5	11.1	4.6
1989	6.4	10.9	4.5
1990	6.2	10.6	4.4
1991	6.0	10.4	4.4
1992	5.9	10.4	4.5
1993	5.8	10.1	4.3
1994	5.6	9.9	4.3
1995	5.5	9.5	4.0

[a] High-grade corporate bond rate.

Sources: These figures are the average of three long-term econometric forecasts: Data Resources Inc., "U.S. Long-Term Review," Spring 1982.

Chase Econometrics, "Long-Term U.S. Macroeconomic Forecasts and Analysis," Third Quarter 1982.

Wharton Econometric Forecasting Associates, "Wharton Long-Term Forecast," June 1982.

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[1] These assumptions correspond to the types of assumptions participants are using for the ANGTS project.

Canada

Year	Inflation (GNP deflator)	Interest rates (note a)
1983	7.5	14.8
1984	6.5	14.0
1985	8.1	13.2
1986	7.1	12.2
1987	6.4	11.5
1988	6.6	11.1
1989	6.4	11.0
1990	5.7	10.8

[a]Prime rate.

Source: Chase Econometrics Canada, "Canadian Macro Service," Nov. 19, 1982.

(4) Wellhead prices (Assume NGPA wellhead ceiling prices for all alternatives. The U.S. inflation factors above were used to project wellhead prices. Historical GNP price deflator indexes were used for 1977-82.)

Year	Jan.	Dec.
1977	$1.45	$1.53
1978	1.53	1.64
1979	1.64	1.78
1980	1.78	1.95
1981	1.95	2.13
1982	2.13	2.28
1983	2.28	2.43
1984	2.43	2.59
1985	2.59	2.76
1986	2.76	2.95
1987	2.95	3.15
1988	3.15	3.35
1989	3.35	3.56
1990	3.56	3.78
1991	3.78	4.01
1992	4.01	4.25
1993	4.25	4.50
1994	4.50	4.75
1995	4.75	5.01

(5) Financial assumptions

--An after-tax rate of return on equity of 17 percent would be acceptable. No salvage value for the system is assumed.

--Equity/debt ratio for the project is assumed to be 25-percent equity and 75-percent debt.

--Depreciation of elements of the system should be in accordance with the Economic Recovery Tax Act of 1981 (P.L. 97-34) and the Tax Equity and Fiscal Responsibility Act of 1982 (P.L. 97-248). These laws contain accelerated cost recovery schedules for depreciable assets and require that interest and taxes incurred during the project's period of construction be capitalized.

DESCRIPTION OF GAO CONTRACTOR WORK ON ALTERNATIVES TO ANGTS [1]

Parsons Brinckerhoff Quade and Douglas, Inc., "Report on Engineering Costs Associated with Transporting Alaskan Natural Gas by an All-Alaska Pipeline System." Jan. 1983.

This study prepared a conceptual plan and engineering cost estimate for an all-Alaskan pipeline system moving Alaskan North Slope natural gas from Prudhoe Bay to a warm water port on the south coast of Alaska and then to market by a fleet of cryogenic (LNG) tankers. The study considered a base-case conceptual design and the effect of certain specified design variations to that base case. The study includes conditioning the gas on the North Slope of Alaska at Prudhoe Bay, transporting that gas by pipeline to Cook Inlet on the South Coast of Alaska near Anchorage, liquefying it, and shipping it to markets in Japan, Korea, and the lower 48 States. The study was limited to consideration of five design cases involving two different pipeline diameters, three gas transmission pressures, and two throughput quantities. To these five design cases were added the effect of varying the terminal locations in Cook Inlet, the possibility of conditioning the gas at Cook Inlet instead of at Prudhoe Bay, and the effect of different combinations of product destinations and ship fleet make-up (new or used LNG carriers or both).

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Thomas, Dr. Carl O., "Methanol as a Carrier for Alaskan Natural Gas," A Technical and Economic Review. Nov. 1982.

This report analyzes an alternative method for delivering the energy content of the North Slope gas via conversion to fuel-grade methanol (methyl alcohol), a liquid fuel, and its delivery to Valdez, Alaska, through the existing TAPS pipeline. The technical and cost aspects of this concept have been analyzed in a number of previous studies. Dr. Thomas' work consolidates, updates, and evaluates the economics and other information affecting the methanol alternative. Additional comments are provided on some of the more important technical aspects and uncertainties surrounding a methanol project.

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Tussing, Arlon R. and Connie C. Barlow. "The Struggle for an Alaska Gas Pipeline: What Went Wrong?" Nov. 1982; and "Use in Alaska of North Slope Natural Gas: A Survey of Prospects and Their Likely Impacts on an Alaska Gas Pipeline." Nov. 1982.

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[1]Copies of these reports should be requested directly from the Resources, Community, and Economic Development Division, GAO. (See 4 C.F.R. 81.7 for applicable fees.)

The first report is an assessment of what went wrong, and what, if anything, can be done to make the ANGTS project viable. It updates several previous reports by these authors and suggests that any successful pipeline project will have to meet 16 rules of viability.

The second report looks at the scale of in-State use that could be expected for natural gas. It examines those activities which would (1) utilize the gas right on the North Slope for oilfield operations, including enhanced recovery of oil; (2) process it into a nonfuel commodity (such as petrochemicals) destined for markets outside of the State; or (3) actually consume the gas within Alaska for a variety of energy applications.

GAO CONSULTANT REVIEW PANEL

Mr. John Adger, Former Director, FERC, Alaska Gas Project Office.

Mr. Michael Baly, American Gas Association (Ms. Lorraine Cross, alternate).

Mr. Frederick Boness, Former Deputy Commissioner of Natural Resources, State of Alaska.

Mr. Paul Kobrin, American Petroleum Institute.

Mr. Dennis Dooley, Former Director of Transportation, Planning and Programming, State of Alaska.

Dr. Jerome Hass, Graduate School of Business and Public Administration, Cornell University.

Dr. Ronald Minet, Chairman, Kinetics Technology International Corporation (Dr. Patrick Sweeney, alternate).

Mr. Richard Rowberg, Chief of Energy Programs, Office of Technology Assessment.

Mr. Adam Sieminski, Vice-President, Washington Analysis Corporation.

METHODOLOGY FOR DERIVATION OF MINIMUM CHARGES FOR ALASKAN GAS, LNG, AND METHANOL

We estimated the minimum charge associated with ANGTS, an all-Alaskan pipeline, and a methanol project. This charge is one that does not provide any wellhead return, any royalty or severance tax payments, or any property taxes. It is roughly equivalent to the processing and transportation charge for each project.

In any particular project cost estimate, there are two basic cost categories--(1) fixed costs (associated with construction costs) and (2) variable costs, also called annual expenses. For a project to continue operating in any given year, all annual expenses must be covered by revenues. For profitable projects, revenues must also cover some portion of fixed capital costs on an annual basis. The specific portion is a function of financial parameters such as the project's lifespan and required rate of return. A requirement for starting a project is that it be profitable throughout its lifespan.

ANGTS--FIXED CAPITAL COSTS AND ANNUAL EXPENSES

ANGTS has four fixed capital cost components--the Alaskan pipeline segment, gas conditioning plant, Canadian pipeline, and lower 48 States pipelines. (We have excluded the cost of the pre-build from this calculation since its costs are already being recovered in the rate base.)

Operating and maintenance costs are the only annual expenses for ANGTS included in our analysis.

ALL-ALASKAN PIPELINE SYSTEM--FIXED CAPITAL COSTS AND ANNUAL EXPENSES

The all-Alaskan pipeline system is separated into six fixed capital cost components--(1) pipeline, (2) compression/chilling facilities, (3) conditioning/LNG plant, (4) marine terminal, (5) tank farms, and (6) LNG ships. The first three components vary according to whether the project is designed for a dense-phase or conventional transmission system. (Ship costs were not included in our initial determination, rather, tanker fees were later added to the minimum charge.)

Annual expenses for this alternative consist of operating and maintenance costs.

METHANOL--FIXED CAPITAL COSTS AND ANNUAL EXPENSES

The methanol project is separated into two fixed capital cost components--(1) methanol synthesis plants and (2) other facilities. The latter component includes required changes to TAPS to accommodate the methanol, storage tanks, and facilities to separate the oil, methanol, and water.

The methanol alternative faces more types of annual expenses. In addition to feedstock costs (we used gas wellhead prices), tanker fees, TAPS user charges, and operating and maintenance costs are included as annual expenses.

DETERMINATION OF INITIAL CHARGE FOR ALASKAN GAS, LNG, AND METHANOL

For each project, each cost component in current-year dollars is added to get total fixed capital costs. A portion of this total expense must be recovered each year. The specific recoverable amount is a function of many factors, most importantly, the project's lifespan [1] and the required rate of return to investors.

As previously stated, our financial assumptions include a 25-percent equity/75-percent debt split on investment, and a 17-percent after-tax return on equity. For this analysis, we also assumed an interest rate on debt repayment of 10 percent in the United States (11 percent in Canada). Finally, we assumed that debt would be amortized on a straight-line basis over the life of each project.

Once total capital costs were determined for each project, we applied the following ratios to determine the present value of debt service amortization and return on equity required in the initial year of the project's operation.

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[1] We have assumed a 25-year lifespan for ANGTS and an all-Alaskan pipeline and a 15-year lifespan for a methanol project.

$$\text{Debt service} = \frac{(0.75 \times C)}{\text{PV of the annuity at 10 percent for X years}}$$

$$\text{Equity return} = \frac{(0.25 \times C)}{\text{PV of the annuity at 17 percent for X years}}$$

Where C = capital costs.
PV = present value of annuity factor.
X = project's lifespan.

These amounts were then added to annual expenses such as operating and maintenance costs.

To determine the minimum charge per unit of product, this sum was divided by the total volume of gas, methanol, or LNG delivered in the project's first year. The resulting unit cost, which is in current-year dollars, must then be deflated to 1982 dollars.

To determine a delivered price, this minimum charge would be added to some anticipated gas purchase (wellhead) price. Taxes, tanker fees, and any distribution costs to deliver the product to its ultimate consumer would also be added before a final delivered price can be approximated.

DETERMINATION OF AVERAGE CHARGE FOR ALASKAN GAS, LNG, AND METHANOL

To determine an average charge for these products over the life of the projects, we deflated the current-year total per-unit-charge by 6 percent annually for 15 or 25 years. These charges were then added. To find an average charge, this sum was divided by the total years corresponding to the particular project's lifespan.

As previously stated, this charge does not include any taxes or royalty payments to the State which would increase the delivered price per unit of product. For example, DOE has estimated that State property taxes alone would add an average 92 cents per mcf over the first 20 years of ANGTS' operation.

DESCRIPTION OF AN ALL-ALASKAN PIPELINE SYSTEM

PIPELINE FROM PRUDHOE BAY TO COOK INLET

The pipeline route assumed for our analysis follows that proposed by the El Paso Company in 1975 (except for a possible alternative crossing of the Brooks Range near the Atigun Pass) to Livengood, near Fairbanks. It then turns south to join the railroad right-of-way at Dunbar; from Dunbar, it generally follows the alignment of the road and rail rights-of-way to the town of Willow, near Anchorage. From Willow, the route travels south, following the Susitna River across the Susitna Flats swamp to an underwater crossing of Cook Inlet to the Kenai Peninsula. From there, the route follows the coast, south, to the base-case terminal at Cape Starichkof.[1] (See fig. 3.) The pipeline is assumed to be buried underground over its entire length, except for major river crossings over the Yukon and Tanana Rivers. The gas is chilled to below freezing (27 degrees F) to prevent degradation of the permafrost over the northern half of the route.

Construction of the pipeline represents the single largest expense for AAPS--approximately $5.85 billion (base case). The pipeline system is designed using generally accepted formulae for the flow of refrigerated gas and assumes the use of X-70 grade steel for the pipe. Higher grades lead to welding control and preparation restrictions, and lower grades require heavier sections, thus increasing the cost of freight.

Cost estimates vary, depending on the degree of difficulty encountered by the geography of the route, including the seismic activity of the route south of Livengood, the subsea crossing of Cook Inlet, and the traversing of major rivers, swamps, and muskeg (peat bog).

LNG PLANT AT COOK INLET

Cook Inlet was selected as AAPS' southern terminus, and three potential LNG plant sites were selected for comparative analysis. Cook Inlet's selection was based on its year-round access for navigation, as evidenced by operations at the Port of Anchorage and at existing oil, LNG, and chemical marine terminals in the area. According to the U.S. Coast Guard at the Port of Anchorage, no particular hazards to navigation are expected because of increased traffic, expected ice, or offshore oil

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[1] Cape Starichkof was recommended by the Federal Power Commission staff in 1975 as the preferred site for a marine terminal.

structures if the LNG terminal is located at any of the three Cook Inlet sites.

Cape Starichkof was chosen as the base-case site for the marine terminal and liquefaction plant. Two alternative terminal locations were given detailed consideration; one avoids the subsea crossing by allowing the pipeline to follow the western shore of Cook Inlet to Granite Point, the other shortens the Cape Starichkof route by locating the terminal 60 miles up the line near the existing LNG plant and terminal at Nikiski.

The three potential sites--Cape Starichkof and Nikiski on the eastern shore and Granite Point on the western shore of Cook Inlet--are practicable sites for a major LNG plant and terminal. Differences among the three sites will not have a significant impact on the viability of the project as a whole.

MARINE TRANSPORTATION ALTERNATIVES

Variations to the base-case shipment pattern would send some of the LNG to Point Concepcion, California, and to Korea. Shipment of the LNG equivalent of approximately 400 Mmcfd to Pt. Concepcion, California, and to Yosu, Korea, would require two and three LNG tankers respectively. Transportation costs based on new U.S.-built ships for the Pt. Concepcion trade and new Japanese-built ships for the Korea trade are estimated to be \$0.57 MmBtu and \$0.61 MmBtu delivered, respectively. (These costs are the transportation charges used in ch. 4.)

The purchase of existing LNG ships was also considered. Existing foreign-built ships, to be purchased in 1987 and laid-up for 5 years prior to the start of LNG shipments, would have an estimated transportation charge of \$0.37 per MmBtu delivered to Tokyo. It cannot be assumed, however, that a sufficient number of vessels could be obtained or that they would, in all cases, be accepted by the Japanese authorities. Delivering LNG to the West Coast using existing American-built ships would offer similar cost savings, with a transportation charge of \$0.27 per Mmbtu.

DERIVATION OF GAO CONTRACTOR'S BASE COST ESTIMATES FOR AN ALL-ALASKAN PIPELINE SYSTEM [1]

GAS CONDITIONING PLANT

The gas conditioning plant's costs were first estimated on the basis of construction on the Gulf Coast and then escalated by a construction cost index of 3.0 for North Slope construction. Cost estimates for the major process actions of carbon dioxide removal and NGL removal were based on previous project designs of the subcontracter--the Institute of Gas Technology--confirmation from appropriate vendors, and vendor quotes.

PIPELINE

The pipeline cost estimate relies on earlier cost estimates developed by the contractor in 1975 during consideration of the Arctic Gas Pipeline System. These earlier estimates were built up from detailed quantities, crew and equipment studies, and unit-rate schedules in a similar manner to that used in the preparation of a contractor's bid estimate.

The contractor used the results of past studies along with costs escalated to present conditions, using pipeline cost indexes or escalation factors. In addition, the cost experience gained from past arctic and subarctic pipeline projects, particularly the Trans-Alaska Pipeline System, and published cost estimates from the Northwest Alaskan Natural Gas Company and Williams Brothers Engineering Company were also reviewed.

LIQUEFACTION PLANT

The subcontractor, Institute of Gas Technology, developed a preliminary cost estimate based on U.S. Gulf Coast construction for a liquefaction plant. This estimate was then escalated by a factor of 1.73 to represent South Alaskan construction. The LNG plant is assumed to use the optimized cascade system to liquefy

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[1]Parsons Brinckerhoff Quade & Douglas, Inc., "Report on Engineering Costs Associated with Transporting Alaskan Natural Gas by an All-Alaska Pipeline System," January 1983. This report was prepared for the General Accounting Office as a result of contract number 3130124. Neither the General Accounting Office, nor any person acting on behalf of the General Accounting Office makes any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report.

approximately 2.05 bcfd of natural gas at an operating efficiency of 94 percent. Six liquefaction trains are needed for the proposed daily output.

MARINE TRANSPORTATION

The LNG transportation study's principal objective was to calculate the number of vessels required and the cost of transporting LNG to potential markets. Estimated construction costs for new LNG ships built in the United States and Japan were developed from published information, previous studies conducted by the subcontractor, John J. McMullen Associates, and discussions with shipyards. The shipyard contract price estimates were based on a 1986 delivery and deescalated at 8 percent per annum (for U.S. construction) and 5.5 percent per annum (for Japanese construction) to the 1982 base.

In addition, the contractor's transportation planning tool, a marine transportation simulation model, was used to estimate the consequences of interaction at the loading port of vessels operating on different trade routes. Port delays, due to port operating rules, and the tankage capacity required at the loading port to minimize vessel delays were estimated by this model.

PRICE RANGE COMPARISONS FOR DELIVERED METHANOL

Volume (586,000 barrels/day, 74,000 MTPD, or 8.98×10^9 gallons/year)

Unit size = 2,000 MTPD	Low case	High case
Capital costs for methanol units	13.70	18.00
Other capital costs	1.73	1.97
Total capital costs	15.43	19.97
Lifetime	15 years	5 years
Pre-tax rate of return	20%	30%
A = Annual cash flow requirement re: capital costs	3.30	8.20
Annual expenses:		
Feedstocks	2.11	2.11
Pump fuel	0.05	0.09
Tanker shipments	0.15	0.15
Other operating and maintenance	1.54 (@ 10%)	5.00 (@ 25%)
	3.85	7.35
Subtotals	$\$7.15 \times 10^9$	$\$15.55 \times 10^9$
FOB Price	$0.80/gallon	$ 1.73/gallon
Pipeline user costs	- (marginal)	0.10 (linear)
Totals	$0.80/gallon	$ 1.83/gallon

Average = $1.32/gallon ± 40%

Source: Dr. Carl O. Thomas, "Methanol as a Carrier for Alaskan Natural Gas," Nov. 1982.

APPENDIX XI

POTENTIAL FUEL USES FOR METHANOL

GASOLINE OCTANE ENHANCERS

Methanol is now profitably used to produce gasoline octane enhancers. Approximately half of the volume of the final enhancer is methanol. Several factors will influence the future demand for these octane enhancers. Restrictions on gasoline lead content are a positive factor increasing their potential use; EPA restrictions on maximum blending levels are a negative factor. A theoretical maximum for this domestic use is about 20,000 MTPD of methanol, which would absorb less than a third of the output from a full-scale Alaskan methanol project.

GASOLINE BLENDING AGENT

Methanol can also be blended directly with gasoline in either a low- or high-level blend. The percentage of methanol in low-level blends is up to 4 or 5 percent, while the percentage for high-level blends is 15 or 20 percent methanol. Methanol in the low-level blends appears to be more attractive because few, if any, vehicle engine changes are required. Mixing methanol at low levels raises the octane rating of the gasoline without harmful effects on engine performance. (These results are based on industry's experimental fleet use of low-level blends over the past decade.) The higher level blends appear to be less attractive because engine changes are required. The cost of these changes varies, depending upon whether they are performed retroactively on existing automobiles, in which case they are relatively expensive, or whether automobile manufacturers design the changes for an assembly line of automobiles. While the changes for an assembly line vehicle may be less expensive, high-level blends are not popular because they do not achieve the unique benefits attributed to the use of methanol as a "neat" fuel.

NEAT METHANOL FUEL

Many groups, including the Ford Motor Company, believe that neat methanol has the greatest long-range potential for transportation applications of methanol. This use may have the advantage of limiting U.S. dependence on petroleum feedstocks for gasoline. Neat fuel is usually defined as fuel containing over 85 percent methanol. Special engines can be designed to achieve greater energy efficiency (miles per Btu) from neat methanol fuel. However, methanol use also results in lower fuel economy (miles per gallon) because each gallon of methanol has only about half the Btu's of a gallon of gasoline. This lower fuel economy means that a full fuel tank of methanol carries a vehicle a much shorter distance than a full tank of gasoline.

Several fleets have experimented with this methanol use. Since few automobiles have been built in the United States to use neat methanol, changes in existing engines have been required. Estimates of the costs of these changes range from $1,000 to $1,500, according to previous studies. For neat methanol to achieve widespread use in transportation applications, automobile producers would probably have to mass produce methanol engines, which could add about 5 percent to the total cost of the automobile. Other costs involved would be some required changes in the gasoline station distribution system to handle the new fuel. After these changes were made and if methanol could be priced competitively, methanol use as a neat fuel could be a large new market.

METHANOL AS A UTILITY FUEL

A further proposed fuel use of methanol is in powerplants as either a boiler or gas turbine fuel. Few equipment changes are required to use this fuel, and studies have indicated that technology is not a problem. Moreover, harmful plant emissions could be reduced if methanol were used. This factor would be particularly relevant in areas where air quality is of major concern to utilities. Methanol could also be useful in increasing the capacity of existing older plants where operation is restricted because of emissions. However, public utility commissions would have to give additional rate base credits (for pollution reduction) for methanol use before methanol is likely to be competitive with prices of other fuel sources. Although our discussion is based primarily on California's experience, we believe that, in the near future, most utilities are likely to continue to rely on traditional fuels since California has some of the Nation's most stringent air quality requirements and could be considered a primary market for this methanol use.

NORTHWEST ALASKAN PIPELINE COMPANY

DARRELL B. MACKAY
SENIOR VICE PRESIDENT
REGULATORY & GOVERNMENTAL AFFAIRS

March 25, 1983

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Mr. F. Kevin Boland
Senior Associate Director
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Boland:

This responds to your request, dated March 15, 1983, addressed to John G. McMillian, for comments on certain sections of a draft GAO report entitled "Issues Facing the Future Use of North Slope Gas." Northwest Alaskan Pipeline Company (NWA) is agent and operator for the Alaska Northwest Natural Gas Transportation Company, a partnership that sponsors the Alaskan segment of the ANGTS.

The sections of the draft report provided by your letter were limited to a portion of Chapter 1 (Introduction) and all of Chapters 2 and 3 (Status and Outlook, respectively, for the ANGTS). This material dealt solely with the ANGTS; it did not address other alternatives considered by GAO and did not contain the overall conclusions reached by your study. Nevertheless, we are pleased to provide comments on several fundamental considerations and implied conclusions in the material you provided. The absence of NWA comment on specific statements in the report should not necessarily be construed as an NWA endorsement of such statements or of any part of the report or its conclusions, except for statements directly attributable to NWA. We look forward to seeing the complete, final report.

We had earlier responded to your staff by providing factual background material and our views on a number of subjects related to the ANGTS, and we have been impressed by their thoroughness and professional approach to this subject. Our comments are contained in the enclosure.

Very truly yours,

Darrell MacKay

Darrell B. MacKay

DBM/rlc

Enclosure

A SUBSIDIARY OF NORTHWEST ENERGY COMPANY

3/25/83

Comments by Northwest Alaskan Pipeline Company (NWA) on Certain Sections of a Draft Report Entitled "Issues Facing the Future Use of North Slope Gas"

National Security/Energy Self-Sufficiency

The sections of the report we received for comment made no mention of overall U.S. national security interests associated with bringing Alaskan gas to the lower-48 States. This, of course, was a key motivation of the U.S. Congress when it passed the Alaska Natural Gas Transportation Act of 1976. Although certain conditions have changed since 1976, we believe it is important to recognize that Alaskan gas is the only proven large source of gas available to meet long-term needs of the lower-48 States, i.e., needs in the last decade of this century and extending well into the next century. Temporary marketplace conditions can change rapidly and radically as has been witnessed several times in recent years, and the ANGTS sponsors believe that long-term U.S. interests in energy self-sufficiency should not be jeopardized with respect to the disposition of Alaskan gas.

The natural gas industry is currently undergoing a supply-demand-pricing crisis, largely as a result of contract rigidities resulting from the application of the statutory price structure established by the Natural Gas Policy Act of 1978. The crisis is compounded by the current low level of economic activity, the uncertainties and impacts arising from the world oil market, and by perceptions stemming from the warmest winter weather in 30 years. Even when the hopefully short-term crisis is surmounted, the U.S. will remain dependent upon insecure foreign sources for a high percentage of its energy needs. A high level of economic activity, moreover, eventually will resume which will increase energy demands and add to the Nation's vulnerability to supply disruptions and adverse pricing decisions by foreign suppliers. Additions to U.S. natural gas reserves, meanwhile, continue to fall below production levels, and it is not unrealistic to envision future natural gas curtailments of the sort experienced in the heating season of 1976-1977.

Alaskan natural gas truly constitutes a "strategic natural gas reserve," constituting 15% of proven lower-48 reserves. We believe this assured long-term supply of energy will be needed to play an important role in meeting U.S. energy requirements in the 1990s and beyond.

In short, while there has been unavoidable delay in moving the project forward at the previously expected pace, we believe the causative factors are temporary, and long-term gas supply-demand projections in the lower-48 States reveal a continuing future need for Alaskan gas. In this setting described above, any suggestion of committing 26 tcf of Alaskan gas to foreign nations is unthinkable from a national security viewpoint.

NWA has been advised that GAO did not evaluate the national security/national defense implications of alternatives or the desirability of U.S. energy self-sufficiency because it was beyond the scope of its study; however, we believe it is most important that these considerations be kept in mind in reviewing the report.

Financing

Although the report is basically factual in commenting on the financing effort, there are several areas where information is somewhat dated or opinions are stated which obviously reflect only extant conditions. In Chapter 2, the status of the Project's financing is reviewed by citing results from an initial report issued by NWA's commercial banking advisors in 1981 (the only such document available) and more recent GAO interviews with Canadian and U.S. banking officials. In the former reference, it should be noted that: (1) although GAO refers to the assumptions and underlying conditions of the 1981 study as "optimistic," GAO points out in a footnote that legal lending limits of U.S. banks subsequently were increased to 15% for an individual creditor in contrast to the 10% limit that was in effect when the bankers' report was prepared, (2) the preliminary survey included 300 U.S. banks and was reduced to 100 for deriving the estimate, which in turn reduced the estimated amount of credit available, (3) the figure was further judgmentally reduced to 80% of the aggregate legal lending limit, and (4) the figures were based on year-end 1980 data. These factors resulted in extreme conservatism in the commercial banking advisors' estimated debt capacity of the U.S. market. Regarding the recent GAO interviews with Canadian and U.S. banking officials, it should be noted that the people who were interviewed commented on the financing of this project in an atmosphere of highly depressed economic conditions and the current perceived glut of oil and natural gas. Understandably, they would be prone to paint a bleak picture regarding the outlook for lending to the ANGTS or any other major energy project. As discussed above, in the second paragraph under "National Security/Energy Self-Sufficiency," a change in underlying circumstances would bring a corresponding change in opinion for the prospects of financing.

Roll-In Cushion For Alaskan Gas

The report correctly recognizes that the roll-in cushion of low priced old gas will be too small by itself to completely absorb the relatively high priced Alaskan gas. A recent GAO report (GAO/RCED-83-13 of February 3, 1983; page 2) estimated that about 10% of all domestic gas would remain controlled by 1990, presuming continuation of NGPA regulation. If such a roll-in cushion indeed exists, even if it were only 6%, it would of course be helpful in marketing Alaskan gas, as was intended by the Congress under the NGPA. In 1990, Alaskan gas would represent about 5% of the projected total annual U.S. gas supply, and the average U.S. gas price would be only moderately effected by any such roll-in. NWA, however, wishes to make an additional point. The roll-in possibility has not been a key consideration in the sponsors' planning for marketing the gas. It is not a prerequisite for marketability and, hence, is not viewed as an issue by NWA.

State Public Utility Commissions

We believe the report overemphasizes State Public Utility Commissions' (PUCs) reluctance to accept Alaskan gas. PUCs do not have legal jurisdiction to deny a FERC-approved tariff for interstate gas movements. NWA believes that the PUCs will not, in any event, be a significant issue because of the sponsors' intent to levelize the tariff to ensure that gas is priced at market clearing levels. Under these circumstances, and assuming a FERC-approved tariff, there should be no real issue regarding the PUCs.

Projections of Future Gas Prices and Demand

The GAO assumes certain wellhead and burnertip gas prices in 1990 with which Alaskan gas would have to be made competitive. These prices were derived from the above-referenced GAO study of February 3, 1983. The caveats in that study are significant, and the uncertainty that attaches to any projections of future gas prices and gas demand should be recognized by readers of this current GAO report. Relevant statements in the February 3 GAO report include the following:

> "GAO's results are very sensitive to two key assumptions--future oil prices and the effects of contract provisions between natural gas producers and pipelines."

> "Due to the competitiveness of oil and natural gas as substitute fuels, however, these results are very sensitive to alternative oil price assumptions."

> "...a contract-induced price increase could range anywhere from no appreciable change to as high as 80 percent above 1983 market clearing prices...."

> "The quantitative results of this report should be taken cautiously...."
>
> "Our conclusion that the NGPA will not lead to a large price increase in 1985 is very sensitive to oil price assumptions."
>
> "The future impacts of alternative policies are inherently uncertain...."

The February 3 GAO report also assumes a significantly lower demand for natural gas in the industrial sector in 1990 than others who have analyzed the subject (i.e., U.S. Department of Energy, DRI and AGA). Projected future gas prices are based on a set of assumptions that are set out in Volume II of the February 3 GAO report, including for example, a statement that: "We expect industry to use 30-55% more coal and 30-35% more wood in 1990 than it does today." NWA believes such assumptions are of questionable validity due to environmental and other constraints. The resulting GAO conclusions regarding future gas prices and demand are clear: "Since we [GAO] do not believe that industrial demand (in 1981) was held back by any lack of gas supply, we see no corresponding price increase due to latent industrial demand." NWA submits that, in the regulatory and market environments of recent years, it is not surprising for a variety of reasons that industrial demand for gas has not burgeoned. We do not believe that these conditions realistically can be extrapolated indefinitely into the future and, accordingly, foresee a much higher future demand for gas than does GAO.

The February 3 GAO report, moreover, contains a significant inconsistency between two conclusions in the report, i.e., between a projection of low industrial sector demand and a finding that, under "Price Decontrol in 1983," the gas market would clear at an average wellhead price of approximately 50% of crude oil prices. It would appear that these two conclusions are mutually inconsistent. Market clearing at a level as low as 50% is likely to occur <u>only</u> if industrial demand is maintained, and there is significant competition between gas and residual oil. If industrial demand is <u>not</u> maintained, the competition would be primarily betweeen gas and higher priced fuel oil, and the market clearing price would thus be at a much higher percentage of crude oil prices.

The significance of these observations is that future projections of gas prices and demand are inherently uncertain and highly dependent upon assumptions. Indeed, the most recent OPEC oil price is below the 1983 oil price assumed in the February 3 GAO study, clearly demonstrating the hazards and unpredictability of hinging vital U.S. interests on predictions of foreign oil prices which could re-escalate as rapidly as they have descended. Under such circumstances, NWA believes it is imperative that the American public keep firmly in mind the essentiality of having "insurance" against faulty future projections, i.e., the insurance represented by the long-term assured supply of Alaskan gas.

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