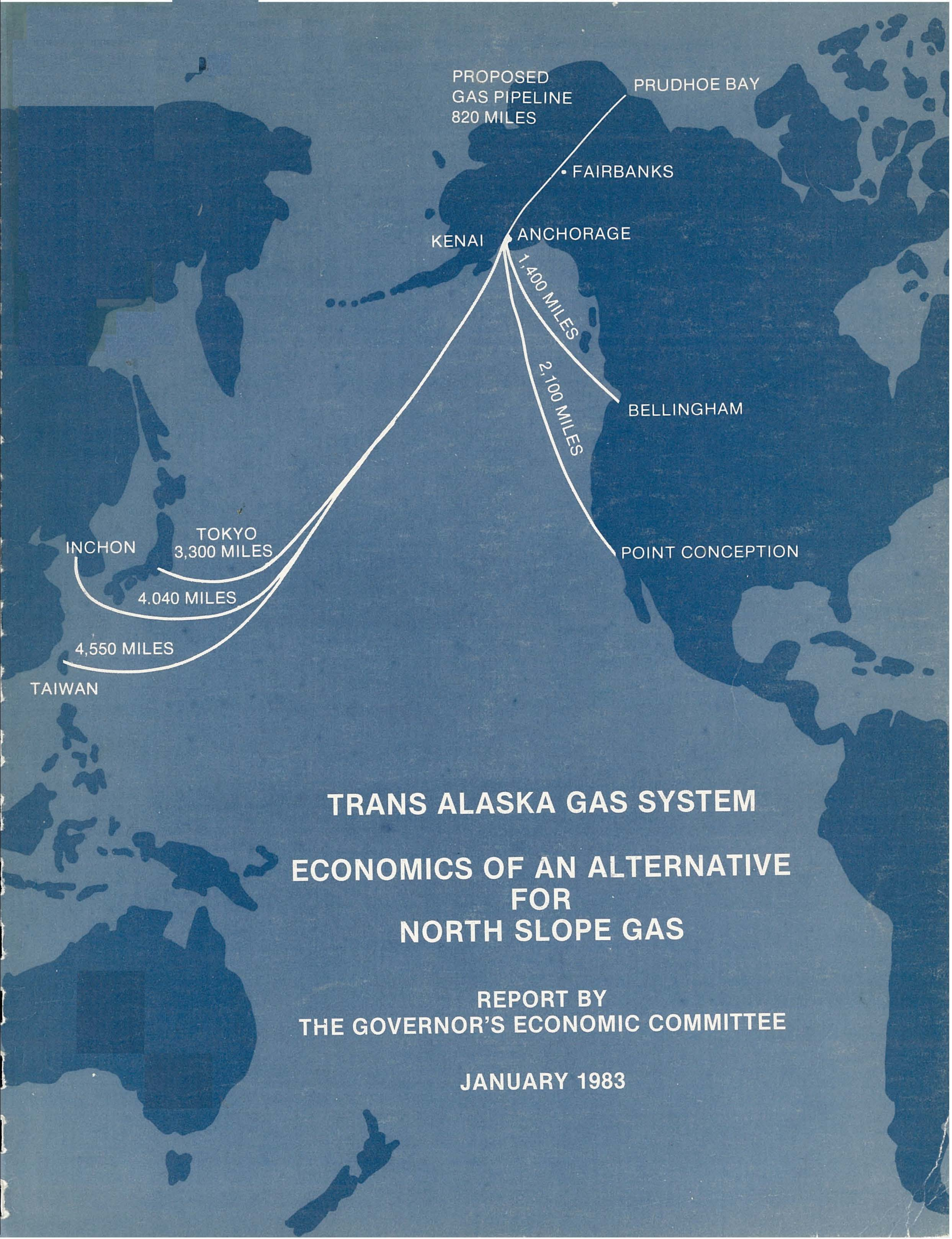

TRANS ALASKA GAS SYSTEM

ECONOMICS OF AN ALTERNATIVE FOR NORTH SLOPE GAS

REPORT BY
THE GOVERNOR'S ECONOMIC COMMITTEE

JANUARY 1983

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TRANS ALASKA GAS SYSTEM: ECONOMICS OF AN ALTERNATIVE FOR NORTH SLOPE NATURAL GAS

REPORT
BY THE GOVERNOR'S ECONOMIC COMMITTEE
ON NORTH SLOPE NATURAL GAS

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JANUARY 1983

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ACKNOWLEDGEMENTS

The Governor's Economic Committee on North Slope Natural Gas is grateful to the following collaborators and advisors whose assistance made this study possible.

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Executive Summary and Conclusions

I. Introduction

This Committee report offers three major considerations for action:

First, the lack of prompt development of a transportation system for moving Prudhoe Bay natural gas and liquids is resulting in a lost opportunity for the nation, state of Alaska and producers of the gas to gain economic benefits and new energy supplies.

Second, the Japanese market for liquefied natural gas will double, at least, by the end of the decade. Anticipated Japanese demand has caused owners of natural gas in Canada, Australia, Indonesia and the Soviet Union, among other nations, to plan and build gas transportation systems to meet this market.

Failure on the part of all owners of Prudhoe Bay gas to act expeditiously in meeting a portion of Japan's needs may irrevocably eliminate any future participation in Alaska's most natural market and could prevent sale of North Slope gas in market through the end of the century.

Third, the Committee's report outlines a Trans Alaska Gas System which can be built, may compete in world markets, is flexible in its ability to respond to changing markets, and offers the nation and Alaska substantial benefits as it responds to the problems cited above.

Fourteen years ago, the largest quantity of oil and gas known to exist in a single North American field was discovered at Prudhoe Bay, Alaska. In 1977, oil began flowing south through the trans-Alaska pipeline. Efforts of the state, the federal government, and private industry to bring that natural gas to an American market have, so far, been unsuccessful.

In June of last year, Alaska Governor Jay Hammond asked two of his predecessors, Walter J. Hickel and William A. Egan and a committee of six other Alaska leaders to seek an alternative system to transport North Slope gas. The Northwest Pipeline project (Alaska Natural Gas Transportation System or ANGTS), selected by President Carter in 1977 to bring the gas across Canada to the central portion of the United States, had just been delayed an additional two years because of financing difficulties.

The Committee is a convenor of experts, rather than expert itself. In transmitting this report to Alaska Governor William Sheffield and the Legislature, the Committee does not presume to make decisions that only the federal government, the state of Alaska, and the gas producers must themselves make. It does attempt to focus public and private discussion toward a proposal that may reach closer to the common goal of bringing Alaska North Slope gas to market.

II. Conclusions

A. The best opportunity: The Governor's Committee on North Slope Natural Gas has determined that a Trans-Alaska Gas Pipeline System (TAGS) from Prudhoe Bay to tidewater with attendant LNG manufacturing and transportation systems provides the best opportunity to deliver North Slope gas to market.

B. Free trade: The Pacific Rim LNG market consisting of Japan, Korea, Taiwan and the West Coast of the United States, is the superior market for Alaska produced resources, including natural gas. America is several years late in approaching this market. Should political barriers inhibiting free trade between Alaska and the Far East be removed now, market forces might allow LNG to move from Alaska to the Far East.

C. National interests: As envisioned, TAGS would make available approximately 4.8 million tons of LNG in 1988. The total system throughput would increase to 14.5 million tons by 1992. Alaska's primary market is Japan. Estimates of Japanese need beyond those sources already committed range from 2 to 9 million tons in 1990 and 9 to 17 million tons in 1995. The possibility of entry of Alaskan gas into this market is increased if:

1. Both nations take their long-term mutual political and economic interests into account.

2. Other projects now planned to deliver LNG to Japan are delayed or found to be less efficient or economic by Japanese buyers.

3. LNG's percentage portion of baseload electric power generation in Japan is revised upward by government and industry decision.

4. Economic growth in Japan rebounds.

D. Higher values: The price of LNG in the Far East has historically been equated to the BTU value of crude oil. It is expected that LNG prices in the Far East will continue to be the highest available to the Alaska energy industry. However, natural gas prices in the U.S. are expected to remain somewhat depressed by the abundance of gas reserves producible at uncontrolled prices. It is unlikely that Alaskan gas will be economically competitive in a free uncontrolled U.S. market over the long term.

E. Lower costs: The Trans Alaska Gas System (TAGS) pipeline with attendant conditioning and LNG manufacturing at tidewater is a concept designed to be built for the lowest possible capital costs. Project economic feasibility also depends upon a number of factors subject to considerable uncertainty such as future energy prices, general rates of inflation, capital costs and construction costs. However, making reasonable assumptions as to these factors it appears that LNG delivered through TAGS could compete in Japanese markets.

same problem w/ ANGTS

	Estimated Cumulative Construction and Organization Costs in 1982 Dollars (Millions)		
	Phase I	Phase II	Phase III
Pipeline	$4,608	$ 6,276	$ 8,243
Conditioning Facilities	702	982	1,423
Liquefaction Facilities	1,863	2,995	4,628
Totals	$7,173	$10,253	$14,294

The projected costs do not include estimates of inflation or financing costs during the construction period, the cost of shipping or facilities outside Alaska.

F. "Base case" costs and tariffs: "Base-case" assumptions used by the Committee's economic advisors to estimate full costs include:

- 7% annual inflation.

- 14% annual interest costs on borrowed funds.

- 30% and 40% annual after-tax return to equity, depending upon equity risk.

- Japanese LNG market price of $7.89 per MMBTU in 1988, escalating thereafter at 7% per annum - i.e. a small decline in real LNG prices from 1982 to 1985 and no real growth thereafter.

Under these assumptions the economic advisors calculated the full capacity (2.83 billion cubic feet of gas per day) or Total System tariff the pipeline would require. Under the 30% equity return case, the necessary tariff would be $5.67 per MMBTU in 1988 dollars leaving $2.22 per MMBTU in economic value for the producers after shipping costs. Total system capital costs would be $14.3 billion in 1982 dollars and $25.2 billion in "as spent" dollars including inflation and financing costs.

III. The Trans-Alaska Gas System (TAGS)

Close to one billion dollars has been spent so far by proponents of various projects to move natural gas off the North Slope. Any project of this magnitude faces hurdles in engineering, marketing, financing, and the law. With these factors in mind, the Committee recommends consideration of a Trans-Alaska Gas System (TAGS). The Committee believes TAGS has enough special characteristics to creatively and flexibly overcome the obstacles which have kept 26 trillion cubic feet of North Slope gas from coming to market.

In devising the Trans-Alaska Gas System, the Committee and its collaborators wanted to meet the following goals:

In engineering, the prime goal is to keep capital costs down while providing pipeline capacity to carry all of the valuable gas liquids - propane, butane, and pentanes - to market.

In marketing, the key word is flexibility. Markets change, the last five years have shown, and a viable project should be able to change with them.

In financing, the goal is to transport the gas to market at a tariff which, given the market price for LNG, provides both an adequate return for System investors and adequate compensation to the owners of the North Slope gas.

In the law, the goal is to devise a project to face as little legal delay as possible. It is recognized that the most economically viable projects must also be politically and environmentally acceptable.

The Committee believes that the TAGS proposal points the way toward meeting these tests.

A. Project Engineering

Brown and Root, the committee's engineering advisors, have estimated how an 820 mile gas pipeline can be built from the North

Slope to tidewater at Nikiski, near Kenai. Construction is envisioned in three phases. If markets demanded more gas, the entire project could be complete in the five year time period allotted for building Phase I. At the tidewater site, the necessary conditioning of the gas, separation of the gas liquids, and liquefaction of the methane and ethane for shipment as LNG can also be accomplished. In 1982 dollars, which do not include expected inflation or the cost of interest in financing the project during construction, Brown & Root estimates the system will be as reflected in table shown on Page 4.

The three phase system was devised for two major reasons. First, it is expected that no market or combination of markets can take all gas available from Phase III of the project immediately, but that a gradual build-up under a phased concept will increase marketability. Phase I was determined to be the lowest cost, lowest throughput system which might stand on its own financially. Second, financing of the whole project may be facilitated as cash flow from one phase is applied to the cost of the next.

Under the phased concept, TAGS would carry the following quantities of gas to be made available for the world market:

	Phase I	Phase II	Phase III
Expected completion date	1988	1990	1992
Raw gas transported, mmcfpd	950	1750	2830
LNG available, million metric tons per year	4.8	8.9	14.5
Propane, 42 gallon barrels per day	19,000	35,000	56,600
Butanes, 42 gallon barrels per day	10,450	19,250	31,130
Pentanes, plus 42 gallon barrels per day	8,550	15,750	25,470

B. <u>Project Marketing</u> The Committee has sought advice on gas marketing from a variety of sources, including several Japanese trading companies, governments in Japan and Korea, Dow Chemical U.S.A., En-Mar Resources, shipping consultants and several oil producers. Conclusions are necessarily those of the Committee itself.

Because TAGS terminates at a tidewater location, North Slope gas would be available to markets in Asia and the West Coast of the United States.

Alaska's history has shown, whenever transportation costs of a commodity are a major factor, that the natural market for its resources is Asia. Alaskan timber, coal, certain fish species, and natural gas have all found markets in Asia before being sold in the continental United States.

The Committee has concluded that the principal market for TAGS would be Japan. That country is the world's largest importer of LNG. The first LNG shipments to enter Japan began in 1969, from the Cook Inlet of Alaska where TAGS would terminate. About one million tons per year of gas are shipped today under that Phillips-Marathon project.

Three factors affecting marketing have been given special consideration by the Committee: expected demand in a market, prices the buyers can be expected to pay, and likely competition from other suppliers. In formulating the TAGS concept from a financial, engineering, and legal viewpoint, the attempt was made to respond to these factors as flexibly as possible.

Typically, LNG sold in Japan is at parity with world oil prices. Prices are higher there than in the United States. In selecting projected world oil prices, the Committee and its economic advisors used the projections of the Mitsubishi Research Institute which predict a real drop in oil prices between now and 1985, and a static real level of prices from 1985 through the end of the century. Inflation over that period of time is predicted at a level of seven percent per year. Other advisors to the committee preducted real growth in oil prices of up to three percent during the same time.

Target projections of Japanese LNG consumption are made by the Ministry of International Trade and Industry (MITI.) MITI's projections are that Japan will increase its LNG demand from 17 million metric tons today to 43 million metric tons in 1990. Other viewers of the scene in Japan place demand projections in a range of 38 to 46 million tons in 1990.

Combined with the uncertainty of Japanese demand, the strength of Japanese commitments already made to other suppliers leaves a question as to how large the near-term shortfall of supply is by an Alaskan project.

Phase I of TAGS would make available approximately 4.8 million tons of LNG in 1988. Phase III, the total system, ready in 1992, would increase TAGS throughput to 14.5 million tons. Estimates of Japanese need beyond those sources already committed range from 2 to 9 million tons in 1990 and 9 to 17 million tons in 1995.

Markets in Korea and Taiwan may also exist for Alaska gas, though demand is undeveloped in both cases. Korea has agreed to import two million tons of LNG per year from Indonesia beginning in 1988; an additional one to two million tons may be needed about 1990. Taiwan supplies its natural gas needs domestically today, but demand projections of up to two million tons in 1990 may signify a market for Alaska gas.

United States west coast LNG markets have been studied for a considerable time by the Pacific Alaska LNG Associates, proponents of a project to bring Cook Inlet and Indonesian gas to Pt. Conception, California. Concluding that Mexican, Canadian and domestic American supplies delivered overland will cover demand through 1990, the Pac Alaska LNG project sponsors recently delayed commencement of construction until at least 1986, with completion expected in 1990.

Prospects of available Canadian and Mexican gas available as well as less expensive production from a large number of shut-in U.S. wells leads the Committee to conclude that North Slope gas does not have a ready market in the United States in the near term. Should demand for Alaska gas materialize on the west coast, LNG facilities could be constructed at Pt. Conception or Bellingham, Washington, according to sources contacting the Committee.

TAGS will also make available a substantial amount of gas liquids to the world market. For the purposes of economic analysis it was assumed these products would command a tariff in the system equally as high as the methane and ethane components of LNG. Typically, measured on a BTU basis, these products are more valuable than LNG components.

Gas liquids made available by TAGS can be exported or used as a feedstock for a petrochemical industry in Alaska. Propane is demanded for use as an LPG motor fuel in Korea and Japan, and conversion of fleet vehicles and taxis in both of those countries is increasing. Ethane, for the purposes of this study, has been shipped with LNG but could be separated to use as a petrochemical feedstock also.

Natural gas and gas liquids can be used as a feedstock for the creation of methanol or electrical power in the State of Alaska as well. Such use would be beneficial to the community and it is especially needed in Interior Alaska today.

C. Project Economics A preliminary economic analysis of the System was prepared by Dillon, Read & Co. Inc. to determine the economic feasibility of the Trans-Alaska Gas System on a project finance basis.

System economic feasibility means an ability to transport, condition, liquefy, and ship LNG and associated products at a cost which, given projected world energy prices, provides both an adequate return for System investors and adequate compensation to the gas producers. Making reasonable base case assumptions, outlined below, it appears that LNG delivered through TAGS could compete in Japanese markets.

Dillon Read used for their base case analyses the following assumptions:

i) Brown and Root engineered construction and operating costs, and construction expenditure schedules;

ii) 7% annual inflation in construction costs and operating expenses throughout System life;

iii) 14% annual interest cost on borrowed funds;

iv) unregulated tariffs, which escalate with projected LNG prices;

v) 75/25 debt to equity ratio for System capitalization throughout the life of the project;

vi) 30% and 40% annual after-tax returns on equity investment, depending upon project risk assumed by equity investor.

Based on the above, Dillon Read projected TAGS "as spent" capital costs, including financing costs during construction, inflation, taxes and working capital for Phase I (completed in 1988) and the Total System (completed in 1992) as follows:

Total Estimated Capital Costs
(Millions of Escalated Dollars)

any contingency

	Phase I	Total System
Pipeline	$ 7,569	$14,648
Conditioning	1,104	2,520
Liquefaction	2,883	8,297
Total "as spent"	$11,556	$25,465

Based on these capital costs, Dillon Read calculated a tariff expressed in dollars per million BTU's which, over the life of the System, would be sufficient to cover operating expenses, service and retire System indebtedness and provide the required after-tax return to an equity investor. Two target equity returns of 30% and 40% were used in Dillon Read's analysis reflecting two possible levels of project risk. The calculated tariffs in 1988 dollars for Phase I and the Total System under the high and low equity return cases were adjusted by adding shipping costs to Japan, as estimated by En-Mar Resources, Inc., the Committee's shipping advisor. This final figure represents the total transportation cost of LNG per MMBTU FOB Japan, but does not include compensation to the gas Producers. Subtracting this figure from projected 1988 Japanese LNG prices gives the economic value of the gas to the Producer. This value is set forth below.

Projected Japanese LNG Prices vs LNG Transportation Cost
($ per MMBTU in 1988)

	Phase I		Total System	
	Low Tariff	High Tariff	Low Tariff	High Tariff
Japanese LNG Price forecast	$ 7.89	$ 7.89	$ 7.89	$ 7.89
Transportation cost landed Japan	6.94	8.91	5.67	7.16
Economic value of LNG	$0.95	($1.02)	$ 2.22	$ 0.73

Dillon Read tested the results above for sensitivity to the various assumptions made, as detailed in their enclosed report.

Under base case assumptions, the Total System tariff produces positive economic values for producer gas under both the high and low tariffs. These indicate that the Total System, under the assumptions made and subject to the availability of markets capable of absorbing Total System output, could be economically feasible in the lower tariff case and may be only marginally economic in the higher tariff case. Phase I appears to be only marginally economic under the lower tariff case and clearly uneconomic as a stand alone project under the high tariff case.

In all cases, economic value and required tariffs can be significantly improved if outside parties can be found to share the economic risks associated with a project of this magnitude. Such parties might include the various direct and indirect beneficiaries of a successful project: the buyers and sellers of the gas, the State of Alaska as both a royalty owner of the gas and as taxing body, and suppliers and contractors to the System. As a minimum, commitments by buyers and sellers of the gas are a necessary precondition to moving from this economic analysis to the formulation of a viable financing plan.

D. The Law Birch, Horton, Bittner, Monroe, Pestinger and Anderson, counsel to the Committee, were asked to look at a number of questions regarding the legal status of North Slope gas and the legal viability of a Trans-Alaska Gas System

A central issue was whether proponents of a Trans-Alaska Gas System would need to seek legislation, as other proposed and completed Alaskan pipelines have. The short answer was legally no, practically yes.

Legally, there is no prohibition on exports of North Slope gas if the President makes the finding that those exports will not adversely affect the supply, price or quality of gas available to the United States. If TAGS were an export line solely, it could leave only its shore plant facilities as matters for FERC approval. Commitments to use the gas in the Alaska Natural Gas Transportation System (ANGTS), codified in legislation and by treaty with Canada, seem binding only if private sources can raise the funds necessary to complete the project. No time limit rests on the sponsors of ANGTS to actually build the project or lose their license under the law.

Practically, experience has shown that the strongest decision-maker in an issue such as this is the owner of the resource, led by the market. Government can restrain building but it is hard, without direct government funding, to force building. However, when the financial resources at stake amount to the largest private construction project in history, it is essential to remove any legal "cloud." Thus some changes in the law to support a President's decision to favor system construction and gas exports would be necessary.

Legislation to put federal aproval on a Trans-Alaska Gas System would either amend the Alaska Natural Gas Transportation Act or replace it with a new, but similar measure. Such legislation could avert drawn-out litigation, motivate federal agencies to act expeditiously, and inspire confidence in the financial community for the project.

IV. Special characteristics of the system

Several special characteristics of this system differentiate it from other proposals to move North Slope gas to market, including the previously proposed El Paso project which would have brought North Slope gas to Valdez for shipment to the United States.

A. Conditioning at tidewater: Costs of conditioning the gas at tidewater are substantially less than accomplishing the same task at the North Slope despite the fact that approximately 12.6 percent of the pipeline capacity must be used to carry carbon dioxide, an inert gas with little expected commercial value. Conditioning on the Slope might also include the process of separation of gas liquids. By moving that process to tidewater, the BTU throughput content of the system is increased, adding to the financial viability of the pipeline.

B. Elimination of NGL Pipeline: The Trans-Alaska Gas System has been envisioned by engineers to carry natural gas liquids in the gas stream. At tidewater, gas liquids can be shipped to market or be used within the state of Alaska as a petrochemical industry feedstock. Thus, a separate $3 billion pipeline needed to carry the liquids from the Slope (although some liquids could be carried in the Alyeska pipeline), as projected by the Dow-Shell Petrochemical Feasibility Study in 1981, would not be necessary.

C. <u>More flexible markets</u>: The Trans-Alaska Gas System makes North Slope gas and its respective components available to the world market because of its terminus at tidewater. Thus, if national security concerns dictate that uncommitted natural gas from Alaska must be used in the United States, it can be. If that gas finds a market elsewhere in the Pacific Rim, it can answer those needs too. Over the real life of the project, which is likely beyond the commitment term necessary for financing, the pipeline could serve many different markets.

D. <u>Ownership of the gas</u>: Traditionally, oil producers have sold gas at the wellhead in the United States because, among other reasons, gas is more highly-regulated than oil. Under the TAGS concept, gas producers could own the gas at tidewater as well as at the North Slope. The advantage to this concept is that a "beachhead" rather than "wellhead" price could be established under certain system ownership and regulatory scenarios. This, combined with the flexible market consideration outlined above, allows negotiated sales terms throughout the life of the project which could provide owners of the gas higher returns.

E. <u>Flexible financing</u>: The Trans-Alaska Gas System is made up of several discrete components which can be owned and financed separately or together. Possible advantages here include use of lower cost financing on some system components through tax exempt debt instruments or import-export financing of a foreign supplier or buyer. Different owners may require different equity returns due to varying financial risks of construction completion. Finally, simply because of the large magnitude of the project, it may be advisable to distribute risks among several different parties.

V. Benefits to the Nation

The Trans-Alaska Gas System has a number of benefits to the nation stemming from increased economic activity, better relations with trading partners abroad, and its contributions toward increased energy exploration and independence at home.

The Committee has made the following findings:

1. New energy supplies: It is vitally important to the Nation that North Slope gas be brought to market. Failure to establish a gas transportation system off the North Slope of Alaska has resulted in dampened interest in exploration in the area. The likelihood that gas will be found in certain tracts has lowered the expected value to the extent that drilling has not taken place in promising areas. Without a transportation system, gas must be reinjected, a costly process.

2. Higher federal leasing revenues: Less than the best revenues from federal and state leasing programs are being received because bids are being discounted by the expected cost of gas reinjection.

3. Help to balance trade: America's continuing trade difficulties with Japan, resulting from a large balance of payments deficit with that country, can be helped with energy exports from Alaska, having economic value in the billions of dollars per year.

4. National security: While United States policy has confined Alaska energy development to meet only U.S. demand for energy, export policies of Alaska's neighbors in the Pacific Rim, including the Soviet Union, are answering the needs of Japan and Asian newly industrialized nations. Over a long period of time, the effect of such trade can be to create stronger alliances potentially at odds with the interests of the United States.

5. <u>Transportation efficiency:</u> Given world markets, the tidewater route is efficient. Today, Alaska's oil goes east through the Panama Canal toward Gulf of Mexico refineries while Mexican oil found in the Gulf heads west toward Japan. A similar inefficient circle stands to be drawn if Alaska gas is forced through Alberta toward Chicago while Canadian gas, under a currently pending export proposal, would leave Alberta in the opposite direction to British Columbia and then venture by ship across the Gulf of Alaska to Japan.

6. <u>Economic growth:</u> Government action to spur the nation's economy should not stop with taxing and spending policies. A regulatory decision at the highest government levels to permit this project, help market the gas, and to increase energy exploration with its completion can stimulate the economic growth of the nation without the use of federal funds.

VI. Benefits to the State of Alaska

No matter how promising a proposal, Alaska stands to gain from a project to move North Slope gas to market only if the project is actually built. In design, routing, choice of suggested markets and legal status, TAGS is conceived to be economic, first and foremost. Side benefits to the community will be substantial, and TAGS contains a number of special benefits for Alaska:

1. <u>Value added industry:</u> Alaska's hopes, a strong underlying force behind statehood, have long been to create primary processing of its natural resources within the state. TAGS, by bringing the North Slope gas to tidewater, ensures this opportunity for Alaska — not only at tidewater but along the entire route of the line.

   If the economics are established, Alaska could become a "Gulf Coast of the North," supplying the petrochemical needs of the Pacific nations similar to the way Texas and Louisiana's gulf coast have served the Atlantic nations for over a generation.

The gas liquids that could be extracted from the gas stream represents one of the largest concentrations of these hydrocarbons found anywhere in the world. Gas liquids are the most efficient raw material for a petrochemical industry. Today, in the Pacific Rim, most petrochemical development is based on raw material derived from more expensive crude oil.

The possibility of using portions of the gas stream for a methanol facility based in the Interior of the state is aided by both the route and the content of the pipeline.

2. New power for the Railbelt: Fairbanks, a city in dire need of low cost power, could make the choice of generating power from gas supplied by the line as it passes near the community. As well, power generated at tidewater can be supplied to the entire railbelt region through the proposed intertie between Anchorage and Fairbanks. In-state power generation from North Slope gas will be possible at points along the route using portions of the full-gas stream and at tidewater using methane or a low-btu gas which would be a byproduct of certain conditioning technologies which may be chosen by sponsors of the project.

3. State revenues: Alaska's economy is unquestionably based on revenues from natural resource development. Long-term prospects for energy exploration in the state can only be increased by moving North Slope gas. Revenues to state government are expected to decline with Prudhoe production declines in the late 1980's, about the same time this project could be expected to come on line. Revenues from TAGS will accrue to the state as an owner of the royalty portion of the gas as well as from taxes on the system itself. Taxes based on the property will bring revenues to muncipalities throughout the system's length.

4. Employment: Short and long term employment opportunities in Alaska are large with TAGS. Brown & Root, the committee's engineering advisors, have estimated that 310,000 man-months of

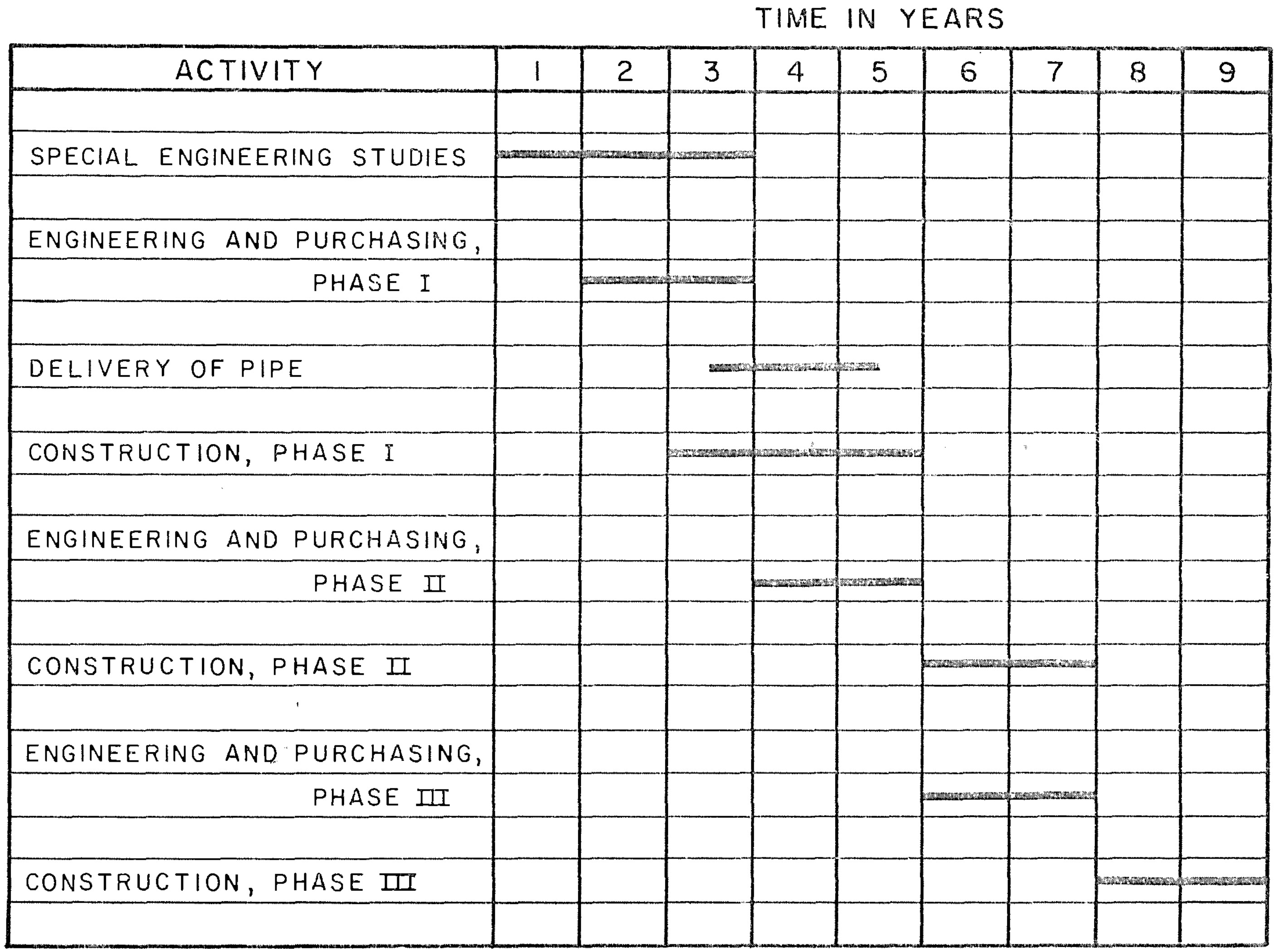
labor will be required during the seven years of construction. Full time project operation will require close to 500 people. Data supplied by the U.S. Bureau of Labor Statistics indicates that for every 100 operating jobs in the pipeline and hydrocarbon processing industries, 90 to 130 new jobs will be required locally for support.

VII. Project's potential timetable

Marketing, financing, and legal approvals will govern the timetable of the project. Taking previous experience in Alaska energy projects into consideration, Brown & Root has supplied the following timetable which the committee feels will meet the ambitions of a project sponsor. Construction could begin in three years and gas could be flowing to the market in five years if the engineering process began in 1983.

Brown & Root, Inc.
PIPELINE ENGINEERING
HOUSTON, TEXAS

TRANS ALASKA GAS SYSTEM
PROPOSED PROJECT SCHEDULE



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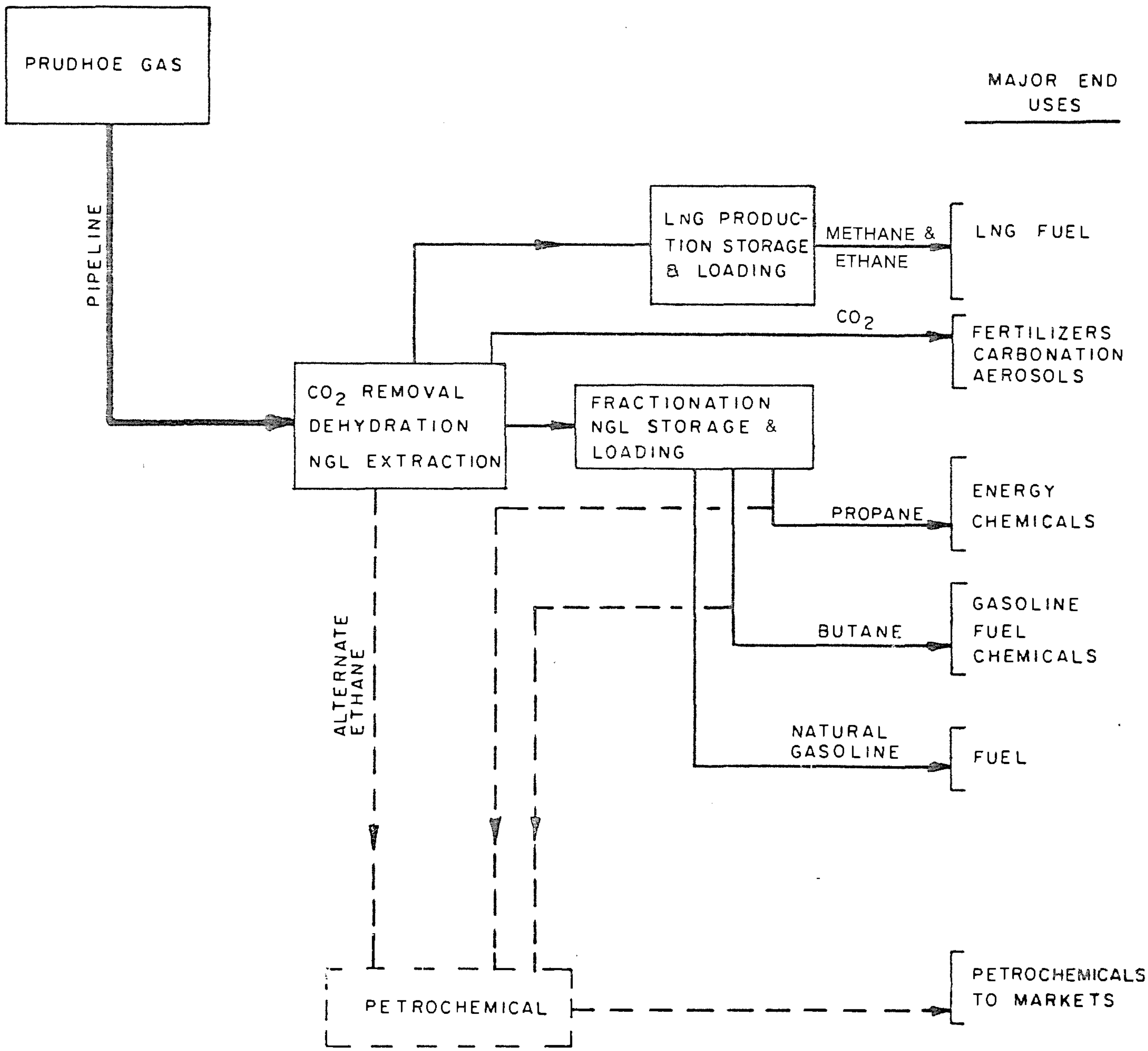

DASHED LINES INDICATES ALTERNATE FEEDSTOCK ROUTE.

SOLID LINES INDICATE UNITS INCLUDED IN THIS REPORT COST ESTIMATE.

Brown & Root, Inc. PIPELINE ENGINEERING HOUSTON, TEXAS		CONT. NO.
TRANS ALASKA GAS SYSTEM **ALTERNATE PROCESS SCHEMES**		DWG. NO. FIGURE I-B
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ENGINEERING

Introduction:

The Governor's Economic Committee on North Slope Natural Gas selected Brown & Root, Inc. as its Engineering consultant and advisor to assist in its study of alternatives for marketing North Slope natural gas.

The information, conclusions and recommendations presented in the following Engineering Section of this report are based on studies made either from historical data contained in Brown & Root's files or from technical expertise from within the Company.

Because of the limited time and budget available for the study no original field work or extended reconnaissance work was performed. Routing for the pipeline has been done by engineers familiar with the area from office map studies with the total length being scaled from topography maps. Quantities of material, modes of construction, production rates, productivity and project concepts have been selected and estimated by Brown & Root professionals who collectively have many years of Arctic experience and are well qualified in this field of expertise.

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TRANS ALASKA GAS SYSTEM

I. TECHNICAL ASPECTS

A. Potential Tidewater Locations

General:

In the time available for this initial study, the engineers made an arbitrary decision to consider only one route to a specific terminal area, rather than making numerous alternate studies. The single terminus area was selected on engineering, legal and economic criteria. In its directions, the Governor's Economic Committee emphasized routing for the lowest capital and operating costs. The engineers were also asked to include in the evaluation legal land status and routing the line as close to Fairbanks as economically justifiable.

The engineers have reconnoitered by helicopter the pipeline routes to most potential locations and are aware of the features hereafter discussed, but have not made what could be considered as in-depth studies of any of the several potential locations.

1. Basic Requirements and Desirable Features:

   (a) Water depth adequate to handle large LNG, liquid hydrocarbon, or petrochemical products tankers should desirably be close to shoreline to minimize loading dock facilities cost. A 45 foot mean low water depth at dock site is tentatively considered as the minimum desired depth. Preferably this depth should be maintained without periodic dredging requirements.

   (b) The dock site should be available for essentially year-round use and therefore should be free of heavy ice conditions which could preclude docking. The location should likewise be relatively free of adverse high wind conditions which could affect docking.

(c) The dock site should have marine approaches considered safe throughout the entire year.

(d) The pipeline terminus location should desirably have an accessible and relatively level pipeline route leading to the location. Terrain features obviously have a heavy impact on total pipeline costs.

(e) The terminal location should preferably have a large (approximately 1000 acres), relatively flat area for necessary industrial plants and green areas. Additional land should be available for associated industries. Soil conditions at the plant site should be suitable for heavy foundations, without need for piling.

(f) Seismic activity and fault zones, if any, will obviously be a consideration. At this time no special studies have been made, but rather conclusions from past experiences have been given consideration.

(g) The availability and ownership of land at the terminus will ultimately require considerable study; however, the selection of specific site locations is considered premature for this initial study.

(h) It is considered highly desirable that the pipeline terminus plant location be near an existing community which has the basic necessities to support the ongoing operating staff. If little or no community exists within reasonable driving distance, an entire new community with total infrastructure would be required. A new community such as this is an expense that this project could ill afford.

(i) A desirable feature for any potential site would be proximity to existing and adequate freight and human transportation facilities including rail, highway and airport with all-year and all-weather capabilities.

2. Prince William Sound Areas

Two separate areas on Prince William Sound have received evaluations for this report. These areas are in the proximity of Whittier and Valdez. Since the advantages and disadvantages are similar, they will be covered with one set of comments.

(a) Advantages:

Both locations possess deep water close to shoreline and are essentially free of ice on a year-round basis. Marine approaches are considered as safe, but obviously in-depth studies would be required to determine any specific hazards created by the additional shipping into these existing port areas. Both sites have existing basic community facilities with Whittier being more limited than Valdez.

(b) Disadvantages:

The terrain features along potential pipeline routes leading into either site would make construction extremely difficult and expensive. Neither site has the appropriate large relatively flat plant sites. While Valdez has a paved highway to the city, there is no rail. Whittier, which has rail but lacks a highway, has a small airstrip which is less than desirable for heavy airfreight.

3. Point MacKenzie Area

(a) Advantages:

The pipeline routing into the Point MacKenzie Area is one of the best routes considered, and large relatively flat areas are available for plants. While the area is relatively close to the cities of Anchorage, Wasilla and Palmer, a bridge across Knik Arm and a paved highway to the site would be considered necessary to take advantage of the available Anchorage facilities.

(b) Disadvantages:

Water depths close to the shore are inadequate and it is believed that continuous dredging would be necessary to keep a deep water channel open to any dock adjacent to the shoreline. Icing conditions would be the same as experienced in Anchorage.

4. Kenai Area

(a) Advantages:

The area near Nikishka has existing petroleum plant facilities, including a gas liquification plant which has been shipping LNG to Japan since 1969. Water depths of 60 feet are available close to the shoreline. The nearby communities of Kenai and Soldotna have existing facilities desirable for any type of additional plants; however, the fresh water supply in the area must be expanded. Numerous large and relatively flat sites appear to be available for plants. An existing paved highway leads to the area and Kenai has a long paved runway adequate for heavy air traffic on a year-round basis. Other pipelines exist in the area and although the crossing of the Cook Inlet is an expensive undertaking, it would not be the first pipeline crossing of this body of water. Thus this terminus is considered as one of the most potentially desirable.

(b) Disadvantages:

The engineers have been advised that since LNG shipments began in 1969, docking has been delayed on infrequent occasion due to ice or strong southwest winds. Each time delays in docking or loading was a matter of hours rather than days. The impact of additional shipping in the Cook Inlet approaches to this location must receive future analysis, but in comparison with other shipping areas around the world, traffic density is slight and increases are not expected to pose a significant problem.

5. Seward

   (a) Advantages:

   Seward has deep water closely adjacent to the shoreline and is suitable for year-round marine traffic. The existing community appears to have the basic necessities to support ongoing plant operating personnel. Although there are some relatively flat sites in the area, such sites are very limited, and might be obtainable only with difficulty and high cost.

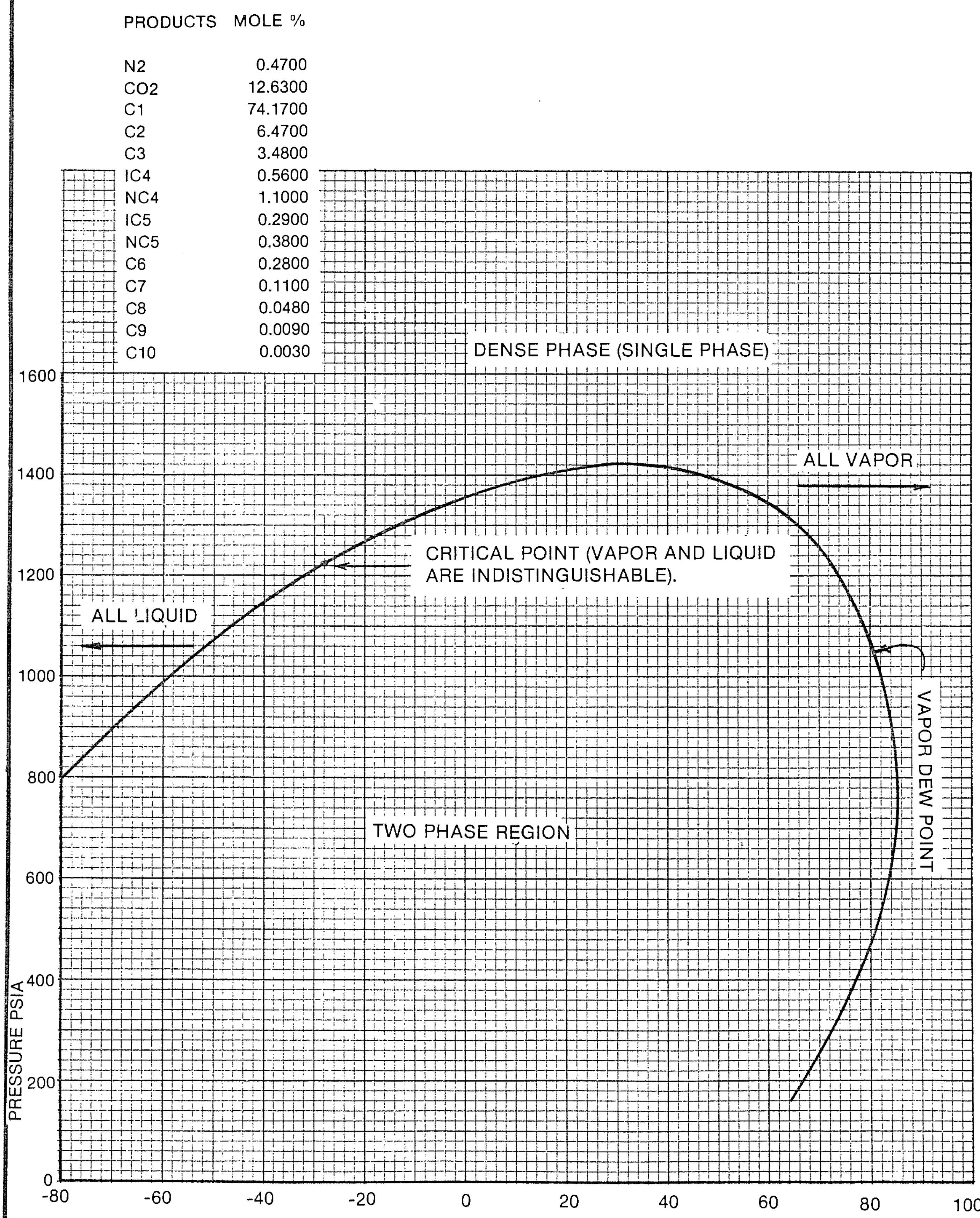
   (b) Disadvantages:

   This location would require approximately 50 miles of extra pipeline to reach the terminus and potential routes in the last fifty or so miles would be very difficult and expensive pipelining. The total project cost in comparison with other areas would therefore substantially increase and be a detriment to project economics.

6. West Cook Inlet

   (a) Advantages:

   The pipeline routing to this area is relatively flat and a crossing of the Cook Inlet would not be required. Deep water is reasonably close to the shoreline. This area should be free of the problem occurring in the Kenai area when the wind is from the southwest. While the large infrastructure investment required would probably make the entire gas pipeline project uneconomic from a private viewpoint, some observers suggest state action to develop the area might allow simultaneous establishment of a coal and gas fed methane industry.



TRANS ALASKA GAS SYSTEM

PHASE ENVELOPE PRUDHOE BAY RAW GAS

FIGURE II-A

NOVEMBER 18, 1982

(b) Disadvantages:

There are no sizeable communities in the area, and no roads, railroads and airports exist. The pipeline route from Point MacKenzie to this area traverses swampy terrain and would require several major river crossings. Plant site areas would present foundation problems.

7. Recommended Site:

For the purposes of this initial study which must concentrate on a single site, the engineers have selected the Nikishka area as best suited, in view of the basic requirements and desirable features. If future considerations dictate a change, much of the routing and economics for this site could be transferred to the study of other areas.

B. NORTH SLOPE FACILITIES

The proposed Trans Alaska Gas System pipeline will be operated at conditions such that only a single gas phase will exist. No gas processing units will be required on the North Slope. The only facilities needed on the North Slope are the existing compressor station and a new refrigeration unit.

1. Compressor Station

The phase envelope of the raw Prudhoe Bay gas is shown in Figure II-A. The highest dew point (retrograde) pressure on the envelope is 1420 psia at 30°F. Some hydrocarbons in the gas will condense at 30°F if the pressure is lower than 1420 psia; therefore, the pipeline must operate at a pressure in excess of 1420 psia. By maintaining the gas pressure above 1660 psig, the pipeline system can be operated with sufficient safety margin to take care of upset conditions and gas composition variations which might affect the phase envelope dew point.

The Prudhoe Bay producers are currently compressing and reinjecting the gas which is in excess of local area fuel requirements. Discussions with the producers have indicated that there is a likely possibility that the existing compressors could serve as the origin station for this project. Discussions have not included possible financial arrangements. Accordingly, this study does not include the capital cost of approximately one billion dollars for an origin compressor station but does include a unit volume compression charge in the estimate of operating expense.

2. Refrigeration Unit

The pipeline temperature must be maintained below 32^{o}F to prevent melting of surrounding frozen soil. Temperature of the gas as received from the field compressors can be as high as 115^{o}F. Cooling will be accomplished by passing the gas through finned tube forced draft air coolers, followed by typical Freon 22 refrigeration units. During the summer's maximum air temperature periods the air coolers will lower the gas temperature to about 90^{o}F, thus requiring the Freon refrigeration units to have approximately 48,000 installed horsepower for cooling the maximum flow of 2.4 billion standard cubic feet per day of gas to 25^{o}F.

During most of the year when ambient temperatures are quite cold it is estimated that only about 15,000 operating horsepower will be required. Future detail design efforts will optimize the balance between air cooling and Freon refrigeration and are anticipated to provide both capital and operating expense savings compared to the initial values used in this report.

3. Dehydration

The raw gas to the pipeline has been dehydrated by existing triethylene glycol units to 0.445 lb water per million standard cubic feet of dry gas; therefore, it is not likely that a separate new dehydration facility will be required. This corresponds to about a minus 20^{o}F water dew point at 2160 psia. No additional dehydration or treatment of the raw gas will be needed to protect the pipeline from corrosion.

4. Gas Processing Facilities

The proposed system avoids any additional gas processing facilities on the North Slope. The gas processing facilities are still required at the southern end of the pipeline, but the installed cost and operating costs will be much lower than that on the North Slope. In addition, a liquids pipeline estimated to cost in excess of two billion dollars is eliminated.

C. The Pipeline

1. Volumes

The marketability of natural gas is a more important factor in determining economic line size than is a reservoir's production capability. The length of a pipeline also has an important bearing on the volume of gas that can be delivered at a competitive cost of service, or tariff. The longer pipeline, and therefore the more costly, requires a greater throughput volume and higher load factor to remain cost effective. With a reservoir the size of Prudhoe Bay, it is possible to develop a gas line so large that the sudden entry of an otherwise economic volume of gas into the market, even in the late nineteen eighties, could result in its inability to be absorbed within the existing markets at competitive pricing.

With this in mind, the economics of this project are evaluated in three phases, namely:

Phase I:	950 MMSCF/D of raw gas (1 intermediate compressor station)
Phase II:	1,750 MMSCF/D of raw gas (7 intermediate compressor stations)
Phase III:	2,830 MMSCF/D of raw gas (14 intermediate compressor stations)

Note (1) 1 MMSCF/D = 1 million standard cubic feet per day.

(2) Each 1,000 MMSCF/D (1 billion) of raw gas will yield the following approximate volumes of marketable hydrocarbons.

Methane & Ethane (3) (LNG)	774.9 MMCF/D
Propane	21,738 Barrels/Day
Butanes	12,023 Barrels/Day
Pentanes & Heavier	9,996 Barrels/Day

(3) Ethane could be separated and used for petrochemical feedstock.

(4) 1 Barrel = 42 gallons.

It should be noted that while Phase I will transport approximately one third of the ultimate volume studied for Phase III, the investment required will be approximately 60% of the ultimate cost (both based on 1982 dollars).

The key economic element in this type of phase-in of volumes is the time span between phases. A large number of scenarios using different time elements is beyond the scope of this initial study. Accordingly, this study is premised upon two year gaps between bringing each phase on line.

2. Line Sizing

The potential phased growth of this proposed system will be accomplished by adding intermediate compressor stations as market demand increases. Should demand ever exceed the practical maximum capacity of the system with an economic maximum number of intermediate compressor stations, the only option remaining is to install partial or total "loops", or parallel lines. Many major gas transmission pipelines in the lower 48 contiguous states have been expanded through installation of 1 or more loops.

Operating this proposed line at a pressure range of 1660 to 2160 psig provides for a maximum capacity of 2,830 million standard cubic feet per day of raw gas in a 36 inch outside diameter, 0.812 inch wall thickness pipeline when the ultimate 14 intermediate compressor stations are installed. This line sizing is based upon the American Gas Association equation for steady state flow as given below:

$$Q_b = 38.77 \frac{T_b}{P_b}\sqrt{\frac{1}{f}}\left[\frac{P_1^2 - P_2^2 - 0.0375\ G\ h\ P_{avg}^2/(T_{avg}\ Z_{avg})}{GLT_{avg}\ Z_{avg}}\right]^{0.5} D^{2.50}$$

where:

D = inside diameter of pipe, inches

f = friction factor

G = gas specific gravity, air = 1

L = pipe length, miles

P_1, P_2 = pressure at beginning and end of line segment, respectively, psia

P_{avg} = average pressure of line segment, psia

P_b = base pressure, 14.73 psia

Q_b = flow rate at base conditions, SCF/day

T_{avg} = average temperature of line segment, $^{\circ}R$

T_b = base temperature, $520^{\circ}R$

Z_{avg} = average compressibility of gas, dimensionless

h = elevation difference between ends of line segment, feet

The term $\sqrt{\frac{1}{f}}$ is commonly referred to as the transmission factor which depends on pipe sizes, pipe roughnesses and flow conditions. For fully turbulent flows, it follows the relationship

$$\sqrt{\frac{1}{f}} = 4 \log \left(\frac{3.7D}{K_e}\right)$$

where K_e = effective roughness, inches

For partially turbulent flows, it takes the form

$$\sqrt{\frac{1}{f}} = \left(F_f \quad 4 \log \frac{Re}{\sqrt{\frac{1}{f}}} \right) -0.6$$

where F_f = drag factor

Re = Reynolds number

$$= 0.0004775 \left(\frac{Q_b \quad G}{\mu \quad D} \right) \cdot \left(\frac{P_b}{T_b} \right)$$

μ = gas viscosity, lb/ft-sec

Calculations were performed by computer, using Brown & Root's "PIPESIM" gas pipeline computer program. Options selected were:

1. Standing-Katz correlation for the gas compressibility factor
2. Mollier method for compressor sizing
3. Adiabatic compression efficiency = 0.73

The following data values were assumed in the calculations.

P_1 = 2,160 psig

P_2 = 1,661 psig

T_{avg} = $25^{o}F$

μ = 0.025 CP = 0.0000168 lb/ft-sec

K_e = 0.00021 ft.

F_f = 0.96

3. Operating Pressures

As previously noted, this proposed pipeline system will operate at pressure above the retrograde condensate dewpoint, calculated to be 1,420 psia. An established minimum design pressure somewhat above the calculated dewpoint is desirable to allow for upset operating conditions and changes in gas analysis which might occur in future operational years. The maximum system pressure has been established at 2,160 psig as this corresponds to the maximum operating pressure of valves, flanges and fittings of Class 900 in API Spec. 6D. Pending optimization studies which should be made prior to final design commitments, a compression ratio of 1.3 has been selected. Thus, the intermediate compressor stations will operate with an inlet pressure of $\frac{2160}{1.3}$ = 1661 psig.

With the establishment of this maximum design operating pressure the pipe wall thickness proposed for utilization was selected in accordance with ANSI B31.8 code for gas transmission systems. The formula is:

$$P = \frac{2\ St}{DxFxExT}$$

where:

P = Design pressure, pisg

S = Specified minimum yield strength, psi. For this project API 5LX-70 pipe having S = 70,000 psi has been selected.

D = Nominal outside diameter, inches.

t = Nominal wall thickness, inches.

F = Construction type design factor. The great majority of this pipeline will be Type A with F = 0.72.

E = Longitudinal joint factor = 1.0 for the Submerged Arc Welded pipe selected

T = Temperature derating factor = 1.0 for design temperatures below 250^{o}F.

Using the above formula the calculated wall thickness is t = 0.771 inches. For purposes of this study the next higher standard wall thickness of 0.812 inches has been selected. A heavier wall thickness will be used in a few areas (as yet to be determined) as required by the code.

It should be noted that operation at pressures above retrograde condensate dewpoint permits the transport of the heavier hydrocarbons in the gaseous phase while simultaneously providing for a given volume of throughput to be transported in a smaller diameter line that would be required for a lower pressure line.

As a comparison, this proposed 36" line operating at the maximum 2,160 psig pressure will have approximately the same throughput capacity as a 48" line operating at 1,260 psig. Although higher pressures require a greater pipe wall thickness when utilizing identical pipe grade, the following comparison is of interest.

36" x 0.812 wall 5LX-70 requires 805 tons steel per mile.
48" x 0.600 wall 5LX-70 requires 880 tons steel per mile.

4. Operating Temperatures

Worldwide pipeline builders have for many decades been confronted with the decision to fully bury or place above ground a proposed pipeline. Many in-depth optimization studies have been made on this subject matter. Without benefit of such studies those individuals without extensive pipeline experience often assume that an above ground pipeline will represent a lower investment. In-depth studies usually prove the opposite is correct. For this project, studies should compare considerations of materials, construction, and maintenance of each type system.

For example, the thermal effects on the pipeline with each system must be evaluated. A fully buried pipeline experiences minimal thermal change, whereas with an above ground pipeline it is necessary to allow for expansion and contraction. This creates the necessity for either expansion loops or above ground directional changes accomplished by movement of the pipe on the support members. Such support members are relatively closely spaced and directly slow the rate of progress of construction. The support members are complex and expensive structures.

A buried pipeline is restrained by the surrounding earth, whereas an aboveground line must be anchored at regular and frequent intervals. Such anchors are large and expensive. In areas where the flowing gas temperature must be maintained below 32°F, pipe insulation would be required due to summer ambient air temperatures. Insulation often costs more than the pipe. Above ground pipelines are usually more expensive to maintain due to an exposure to the elements, mobile equipment and even sabotage.

In an arctic environment the considerations are more complex than in southern areas. Since an optimization study is beyond the scope of this initial study, the engineers have used past experience in deciding that only a fully buried line will be considered for this study.

In areas of permafrost a buried line must either (1) operate at or near the soil temperature or (2) be totally insulated to the extent necessary to prevent heat transfer from the pipeline to the surrounding soil. In areas of discontinuous permafrost the potential for frost heave must be recognized.

Accordingly, the conceptual design and economics of this study are based upon refrigerating the gas as received at a maximum Prudhoe temperature of 115°F down to 25°F, plus removing the heat of compression at each intermediate compressor station in order to maintain the 25°F flowing temperature. The engineers foresee potential cost reductions in both the capital and operating cost estimates as used for refrigeration in this initial study but recognize that any such savings must require confirmation through in-depth studies which are beyond the current scope.

5. Pipeline Route

The proposed gas pipeline system parallels the Alyeska Oil Pipeline from Prudhoe Bay to a point south of Livengood, and at that point passes through a valley west of Fairbanks to an intersection with the Fairbanks/Anchorage highway, then it parallels the highway as far as milepost 696. At this point the pipeline route continues south whereas the highway turns in an easterly direction toward Palmer. The pipeline crosses the Cook Inlet to the Point Possession area, then follows the coastline to the terminus at Nikishka. Overall the pipeline covers 820 ± miles in the route between Prudhoe Bay and tidewater.

(a) Summary of land ownership (approximate)

The land along the route is owned by several agencies and/or groups, and is summarized as follows:

Estimated Ownership	Miles	%
Federal Land	415	51
State Highway Department	223	27
Alaska Railway	68	8
Private Land	5	1
Native Land	8	1
State Land	36	4
Borough Land	50	6
Marine Crossing	15	2
	820	100

(b) Route from Prudhoe Bay, Alaska

The first one hundred (100) miles of the pipeline route is aligned primarily in the flood plain of the Sagavanirktok River. This alignment helps to take advantage of the relatively low ice content gravels in the flood plain and the areas which are thawed by the waters of the river.

The first 12 to 15 miles of the alignment will be placed in ice-rich silt in the upper 10 feet of the soil. Nearly pure ice in the form of wedges, probably up to 20 feet, is a prominent feature of this portion of the route. Similar soil conditions are predominant on the Arctic plains and typify the general permafrost conditions in northern Alaska.

The second one hundred (100) mile segment of the route was also selected to place the line in thawed or low content frozen soils, preferably of granular type. This will be accomplished by following the flood plains of the Sagavanirktok River to the mouth of the Atigun River, then the Atigun River to the Continental Divide at the Dietrich Pass. From the Divide, the route follows the Dietrich and Koyukuk Rivers.

An alternate within this section has been investigated which would permit rerouting of the pipeline to a location west of the point where Alyeksa's Pipeline crosses the Continental Divide. At the point where Alyeska's Pipeline turns east and leaves the Atigun River the Trans Alaska Gas System's alignment will follow the Atigun River to a point of origin near the Continental Divide. At the headwaters of the Atigun River the alignment turns to the east-southeast and joins with the original Alyeska alignment at a point two miles south of Atigun Pass.

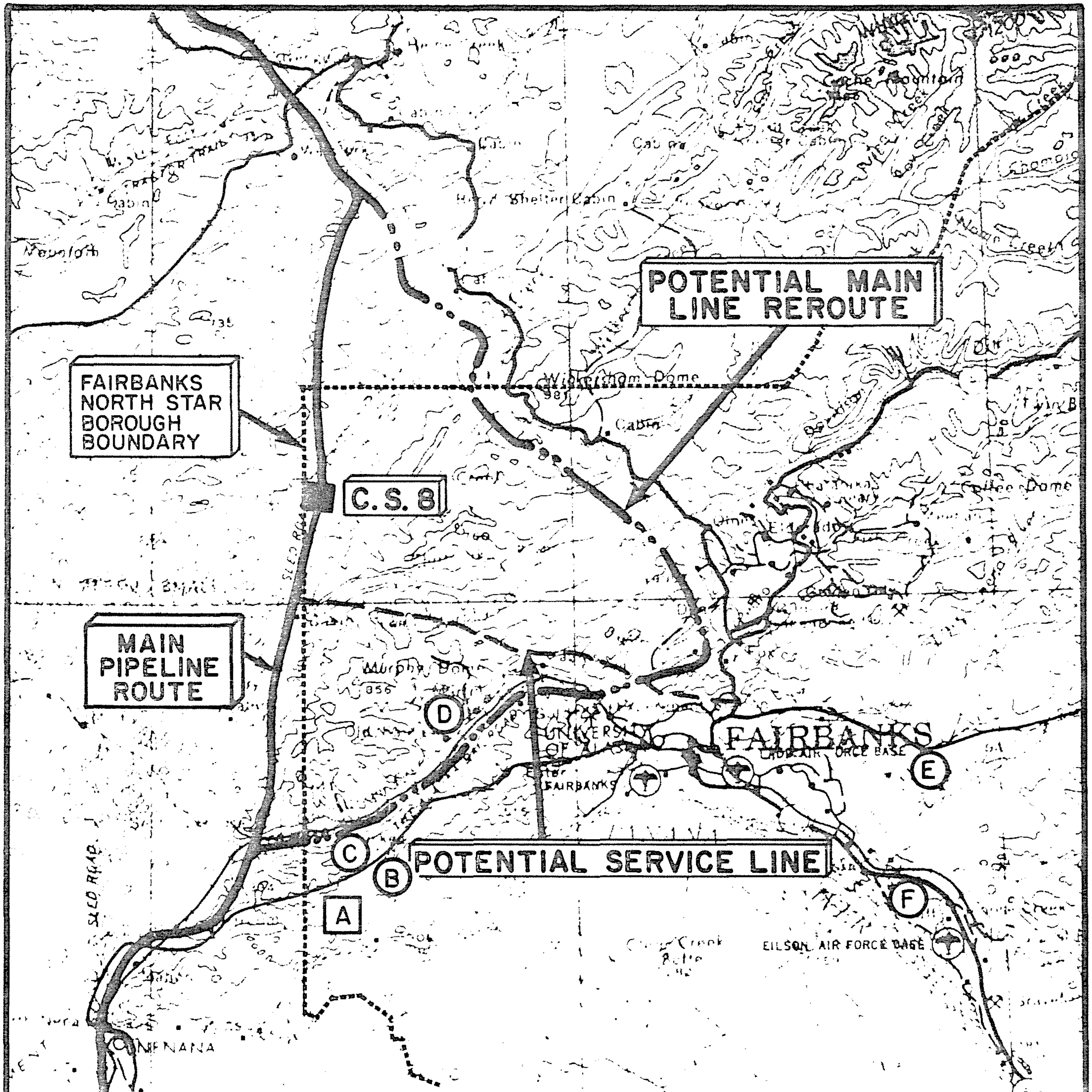
The alignment continues south from the Continental Divide along the Koyukuk River to approximate milepost 240. The route is determined principally by the confines of the Koyukuk Valley and the location of the thawed soil and ice-poor gravels in frozen sections. From this point to the Yukon River the general alignment is determined by the location of the Yukon River Crossing. Most of this portion is through permafrost, with the soil condition becoming generally more severe toward the south. In this section the route crosses hilly terrain with a variety of soils, including gravel, rock and ice rich silts.

The Yukon River is the second largest water crossing and one of the most important along the route. It is a major migrating stream for anadromous fish and it experiences a high incidence of ice jams coupled with accelerated scour. If it is not possible to locate the pipeline on the existing highway bridge across the Yukon River, a proposed crossing point in Rampart Canyon will permit burial in bedrock for maximum security.

In comparison with the northern section of the alignment, the ground profile between the Yukon River and Kenai tends to be more gentle, and the climate warmer on the average, but subject to wider extremes. Higher ground temperatures result in increased sensitivity of the soil to thermal disturbance. The most severe permafrost problems along the pipeline route are encountered in the Tolovana uplands section. These conditions generally decrease in severity to about milepost 470, where thawed soil becomes prevalent.

The basic route proceeds through a valley west of Fairbanks to Dunbar where it intersects with the Alaska Railroad. The land in the area from Fox to Dunbar is generally wet muskeg with low soil bearing values. Accordingly, the line route will basically follow the ridge line on the eastern edge of this swampy area.

Figure II-B shows two possible ways of bringing the pipeline closer to Fairbanks. Routing the main pipeline further east to meet the Alaska Railroad at Fairbanks is one possibility. A spur line from the main pipeline to any plant which might take from the gas stream would be substantially cheaper. Proximity of all three routes to Fairbanks industrial sites, the North-Star Borough boundary, and a proposed Methanol facility are shown on the map.



NOTES:

1. MAIN PIPELINE ROUTE (APPROX. 47 MILES)
2. POTENTIAL MAIN LINE REROUTE (APPROX. 79 MILES)
3. POTENTIAL SERVICE LINE (APPROX. 32 MILES)
4. SITE OF PROPOSED ALASKA INTERIOR RESOURCES CO., INC. (METHANOL FACILITY)
   - A TANANA SITE
5. SITES OF INDUSTRIAL DEVELOPMENT SELECTED BY FAIRBANKS NORTH STAR BOROUGH STUDY
   - B BONANZA SITE
   - C OHIO CREEK SITE
   - D MARTIN SITE
   - E TWO RIVERS SITE
   - F MOOSE CREEK SITE

TRANS ALASKA GAS SYSTEM

FAIRBANKS ALTERNATE

NOVEMBER 18, 1982

FIGURE II-B

The Tanana River crossing at Nenana will be expensive; however, the possibility of using the Alaska Railroad bridge for this crossing will be evaluated during future studies.

From Nenana the route goes south in a broad river drainage area which is basically gravel; however, there is the occasional spot of permafrost. There is the option of utilizing either the highway or railway company right-of-way between Nenana and Liaho.

The route follows the highway right-of-way from Liaho to and through the McKinley National Park and continues along the east side of the highway, using it as a buffer against the Nenana River from McKinley Park to Summit. Summit is the high point on the line south of Fairbanks, and there is a gentle decrease in elevation from here to tidewater.

After Summit, the route goes in a southwesterly direction through a broad valley, which has some gravel; however, indications are there is permafrost through this area. Generally, the highway right-of-way is followed, and at milepost 600, Hurricane Gulch is crossed. The Chulitna River will be crossed at milepost 638 with a conventional buried crossing.

The route goes south from the McKinley area through the Susitna Valley. This area generally follows the highway right-of-way, and it is well drained as evidenced by the size of trees growing here.

At milepost 696 the proposed pipeline route leaves the highway right-of-way heading in a southerly direction. The route diverts around the edge of Nancy Lake Recreation area and heads directly towards the Figure

Eight Lake area, which lies immediately north of Cook Inlet.

The route has a 15 mile marine crossing from the Figure Eight Lake area to Pt. Possession.

From the Pt. Possession area, the pipeline follows an existing oil pipeline right-of-way in a southwesterly direction, a distance of 55 miles to the Kenai area. This is flat, wet land; therefore, construction must be done during the winter season. The land on the Kenai Peninsula is owned by the Borough, State of Alaska, Alaska native corporations and private individuals.

6. Benefits of Route

(a) The expenditure of considerable sums of money during construction and ongoing operation of any industrial facility quite naturally provides an economic boost to any nearby community. Cities and communities along this proposed pipeline route include:

Fairbanks	Talkeetna
Nenana *	Willow *
Anderson *	Wasilla *
Clear *	Palmer
Sealy *	Anchorage
Cantwell *	Kenai
Summit *	Soldotna

* Less than 20 miles from a compressor station.

Typically, a pipeline of this length will employ personnel at an operations headquarters, two or more maintenance centers, and at each of the 14 compressor stations.

(b) This proposed pipeline route is within established transportation corridors for approximately 90% of its length.

For that portion of the route from near Dunbar to about Willow the established railroad and highway will prove to be a major asset to pipeline construction and operation.

The Alaska Railroad is ideally located to transport substantial portions of the 660,000 tons of pipe to be used, plus other project equipment and supplies. Obviously, the proximity of the pipeline route to Highway 3 will benefit both project logistics and the economic health of the communities on the highway.

D. COMPRESSOR STATIONS

Fourteen pipeline compressor stations are suggested for the ultimate volume in the Trans-Alaska Gas System. The number of compressor stations and mile post locations are based on preliminary computer hydraulic analysis only. Specific sites, when studied for terrain, land ownership and other factors may require significant changes in the overall gas pipeline and compressor system.

The compression and gas handling equipment recommended includes the gas turbine driven centrifugal compressor and stand-by unit, all compressor plant ancillary equipment, gas separators, gas refrigeration facilities, turbine fuel system, gas plant piping system, plant monitoring and control system, and compressor building.

Although the two 100 percent capacity compressor unit plan is more costly for the initial one billion SCFD phase of the Trans-Alaska Gas System, this plan is recommended in this initial study in view of saving in investment that can be achieved when volumes increase to maximum line capacity of Phase III, simplicity in operation and the fact that this size of gas turbine driver is in a highly competitive size range, is well developed and has a documented history of reliability.

The suggested compressor station also includes plant offices, control and telecommunications room, power generation, plant heating system, maintenance shops, garage, potable and fire water systems, sanitary sewage, trash handling and incineration systems.

For the purpose of this report, personnel accommodations have been included at every pipeline compressor station regardless of the probability that a residential area may exist within a reasonable distance from one or more of the tentatively located compressor stations. These accommodations consist of single occupancy dormitory rooms with bath; a complete food preparation unit with dining, lounge, game area, laundry and linen storage area; and an emergency clinic facility.

General plant area facilities include streets, walks, area and perimeter lighting, fencing, propane, fuel oil, automotive fuel and lubricating oil storage and handling systems.

The compression of natural gas at each compressor station along the pipeline will create an increase in the gas temperature. This heat of compression must be removed wherever it is essential to maintain the pipeline below 32°F. Accordingly, gas cooling units will be installed at the discharge side of compressor stations. As the pipeline progresses to more southern portions of the route, it may be possible to eliminate some cooling units. However, since this possibility can only be determined through extensive studies, this report includes this costly item at each compressor station.

The wide variations between summer and winter ambient air temperatures along the pipeline's 820 mile length will create variable operating conditions. Accordingly, the cooling units will consist of finned tube, forced draft air coolers and Freon 22 refrigeration units. Dependent upon final design optimization, the air coolers can bring the temperature to within approximately 25°F of ambient air temperature. Air coolers are less expensive to operate than refrigeration units, and during winter months they will provide adequate gas cooling without operation of the refrigeration units.

Operation of the air coolers during the hottest days of summer could add temperature to the gas and thus must be bypassed to direct the gas through the refrigeration units. There are certain air temperature ranges wherein the operation of both air coolers and refrigeration will be advantageous. Complete automation of this operation as air temperature varies will maintain a constant temperature of the gas in the pipeline.

E. TIDEWATER PROCESSING FACILITIES

The proposed pipeline starts on the North Slope and terminates at tidewater. The gas processing facility at tidewater assumes that 2.83 billion standard cubic feet per day of Prudhoe Bay gas is available to the pipeline. The product rates contained in the gas stream arriving in Kenai are shown below, (2.704 BSCFD before deduction for plant fuel).

Products Before Fuel	BPD 60^{o}F	MMSCFD	Higher Heating Value MMBTU/HR.
LNG (HHV = 1064 BTU/SCF)		2,193	97,232
Propane	61,518		9,869
i-Butane	11,763		2,052
n-Butane	22,263		4,042
Pentanes Plus	28,288		5,640
TOTALS	123,832	2,193	118,835

Estimated Plant Fuel = 10% of HHV of LNG Products

Processing facilities at tidewater might include units for NGL extraction, fractionation, CO_2 removal, dehydration, LNG production, petrochemicals production, product storage and loading. (Figure III-C) The final selection of NGL recovery and gas treating process schemes is out of the scope of this preliminary study; however the selection of process schemes will not significantly impact the economics of the overall TAGS system.

1. NGL Extraction, Fractionation, CO_2 Removal, Storage and Loading

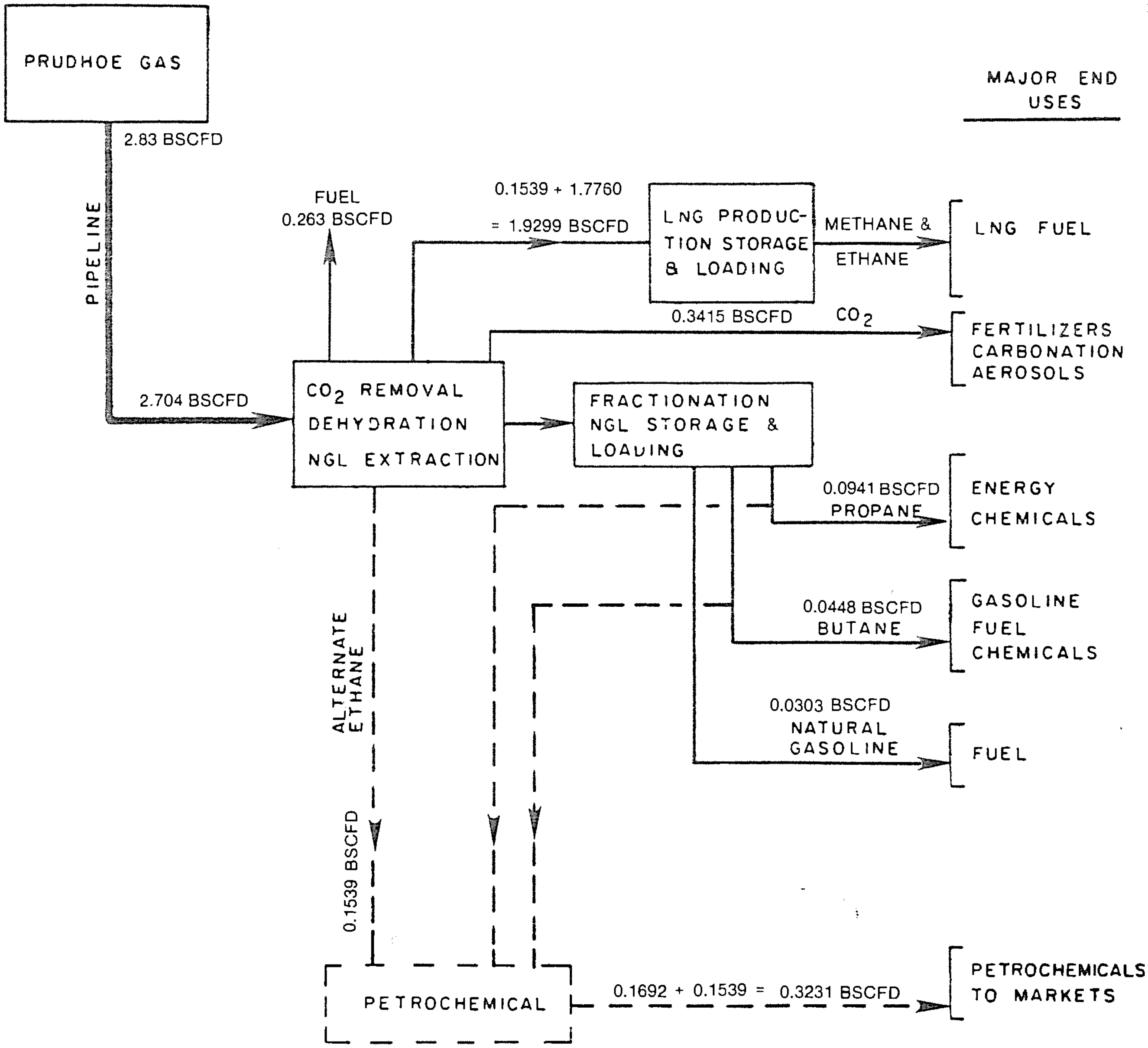
The tidewater processing steps are shown in block diagram form on Figure II-C. The natural gas received at the tidewater plant has not been processed on the North Slope and it contains 12.7% CO_2 and various hydrocarbon components. For LNG production, CO_2 content of the gas stream must be significantly reduced to avoid solid formation in the processing facility.

Propane and heavier hydrocarbons can normally be sold as liquid products at higher values per pound than as a natural gas product. Essentially all these components are recovered in an NGL extraction unit consisting of a cryogenic expander type plant. This unit effectively uses the high pressure available in the plant inlet gas to recover horsepower and refrigerate the gas to condense liquids as the gas expands to lower pressure.

The bulk CO_2 in the natural gas is removed in this part of the plant and the gas is also dehydrated to prevent freeze-ups in the expander unit. For this initial study, the CO_2 removal unit utilizes the Benfield activated carbon process.

The CO_2 gas from the CO_2 removal unit will contain trace quantities of hydrocarbons and hydrogen sulfide. Possible disposition of the CO_2 stream includes petrochemical feedstock, spiking with hydrocarbons to produce low BTU fuel, tertiary oil recovery or venting to atmosphere in tall stacks.

The propane and heavier hydrocarbons recovered from NGL extraction unit are then routed to the fractionation unit. In the fractionation unit, the NGL liquid stream is split into propane, butanes and natural gasoline. The treated gas from the NGL extraction unit, which is basically methane and ethane, is then routed to the LNG unit for LNG production.



THRU PUT VOLUMES PHASE III

12% FUEL IS TAKEN FROM LNG PRODUCT AND EQUALS APPROXIMATELY 10% OF LHV INLET.

DASHED LINES INDICATES ALTERNATE FEEDSTOCK ROUTE.

SOLID LINES INDICATE UNITS INCLUDED IN THIS REPORT COST ESTIMATE.

Brown & Root, Inc. PIPELINE ENGINEERING HOUSTON, TEXAS	CONT. NO.
TRANS ALASKA GAS SYSTEM **THRUPUT VOLUMES**	DWG. NO. FIGURE II-C
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Product storage and loading facilities will be required for the units mentioned above. There will be six refrigerated atmospheric pressure storage tanks of various sizes, and two ship loading berths required to service this phase of the operation.

2. LNG Unit

The LNG unit consists of dehydration, liquefaction, storage and loading sections. Small amounts of CO_2 and water remain in the gas from the NGL extraction facility. The treated gas from the NGL extraction unit is routed to a dehydration section where water vapor and remaining CO_2 are essentially all removed. The dehydrated gas is then cooled and liquefield. The LNG is stored in tanks for shipment in LNG tankers.

Ethane could also be used as a petrochemical feedstock instead of being sold in the LNG product. A different processing scheme would be developed to produce an ethane product.

II. SOCIO-ECONOMIC ASPECTS OF PROJECT

A. Project Potential Timetable

1. General:

Provided all governmental permits and project financing are obtained expeditously during the period of initial engineering, the system can go on stream approximately five years after commencement of activities as shown on the accompaning chart. As noted on the chart, the schedule for Phases II and III which are dependent upon projected market contracts is acomplished without shutdown of activities.

Maintaining such a schedule on a project of this magnitude is dependent upon many variables and is therefore difficult to project. Much will depend upon the worldwide economic climate during materials purchasing and system construction in the middle of the decade of the 80's. When this report was prepared all required materials, equipment and construction contractors were readily available on a highly competitive basis. Accordingly, current conditions indicate that cost and time elements used in this report are considered to be conservative and achievable.

2. Cost Control

Although effects of monetary inflation are beyond the control of this project, maintenance of human discipline from government, management and labor is such a critical aspect of ultimate total project cost that efforts toward control must be established.

Comparison of the Alyeska Pipeline in Alaska with the East-West Crude Oil Pipeline in Saudi Arabia presents an interesting example. Both projects are of the same diameter, length and capacity, and required similar pump stations, tankage, marine loading, access roads and airstrips. Both are remote from industralized manufacturing areas and large population centers which provide local labor. Both required construction camps and heavy logistic support. Both traversed mountains and level terrain. Since the Alyeska pipeline cost was approximately five times that of the Saudi pipeline, the question "why" must obviously be considered.

Certainly a portion of the difference can be attributed to climatic conditions. Additionally, in an admirable effort to protect the environment, perhaps the Federal and State governments created a mental atmosphere that ignored economic reality. Perhaps management, in their eagerness to market the tremendous crude oil reservoir at Prudhoe, too willingly accepted any and all government intervention and regulation. Perhaps labor was guilty of taking advantage of the existing economic times by making unreasonable demands. Nevertheless, whether the high costs of development in Alaska are due to any or all of these reasons, all entities associated with the project should be aware of the following factors that influence cost:

a. <u>Cooperation with government</u>

Government is due some of the blame for the expensive delays and failures of recently proposed energy transportation projects such as the PACTEX and Northern Tier Oil Lines, the Pt. Concepcion Pac-Alaska LNG receiving facility and, if this project is necessary, ANGTS. The "incentive rate of return (IROR)", "one-stop permitting process" of the Federal Inspector and other "experiments" did not create a strong enough atmosphere to keep costs down in the regulatory process. Accordingly, much stronger discipline is necessary.

b. <u>Use of the learning curve</u>

The Alyeska Oil Pipeline was a pioneering effort. Many challenges of arctic construction, new at the time, were met. Another pipeline effort, it can be assumed, can take advantage of the efficiencies of the "learning curve" not only due to the Alyeska experience but from ten more years of Arctic development since the last pipeline was built.

c. Labor agreements

Expectations, based on fact or not, are that a pipeline boom brings extraordinary wages and working conditions; this one might. At the same time, labor-saving advances in technology, such as automatic welding, should be given economic consideration in the field. Discipline in keeping labor costs controlled is essential.

d. Management discipline

Contingencies have been included in the cost projections for this study, but management must use every control tool available to it to minimize the utilization of such contingency funds.

B. Economic Significance to Alaska

1. Employment

In the area of employment the state of Alaska would benefit in two ways.

a. Construction

Previous Alaskan pipeline projects have historically created a large number of construction related jobs. It is important to point out that under the present proposal TAGS would be constructed in a phased approach. The total phase time period would offer construction employment opportunities specifically related to the pipeline project over a nine year period. This is viewed as a major advantage because it controls the construction employment period and reduces the dramatic effect of a short-term employment cycle. The phased approach allows for a more sustained employment benefit. Initial estimates indicate the following approximate man-months of labor will be required for construction:

Pipeline	65,000
Compressor Stations	100,000
CO_2 Removal, Dehydration and NGL Extraction	35,000
LNG Plant	110,000

b. Operations

With the raw gas stream at a tidewater terminus the potential for development of a petrochemical industry exists. Employment opportunities which accompany petrochemical development are viewed as extremely stable and offer excellent long-term advantages to both the community and state. Along with the long-term employment opportunities generated through petrochemicals, the pipeline itself would require a number of operation and maintenance personnel. Historically it is indicated that operations of this magnitude will provide permanent employment as follows:

Pipeline	150
Compressor Stations	100
CO_2 Removal, Dehydration and NGL Extraction	85
LNG Plant	100

c. Associated Job Creation

The creation of new permanent jobs in Alaska will reach far beyond the manpower required to operate the proposed pipeline and hydrocarbon processing facilities. Alaskan employment will benefit from the increased demand in goods and services to maintain the pipeline system and those directly employed by it. This will include expansion of existing services along with growth in local production of goods and services previously supplied from outside of Alaska.

Data supplied by the U.S. Bureau of Labor Statistics indicates that for every 100 operating jobs in the pipeline and hydrocarbon processing industries, an average of another 90 to 130 jobs will be required locally to support the daily needs of the equipment and the workers. The harsh climate of Alaska could skew these numbers even higher.

New jobs will likely appear in a variety of areas. New offices, processing plants, and homes will require expanded gas, electric, and water services. Trade growth from the sale of pipeline products as well as goods at the retail level will open new positions, and rail, water, truck, and air transportation will expand to handle this trade. Local computer and communication services will be required to meet the needs of the modern pipeline and processing plants.

Machine shops will likely appear near the processing plants to repair or remanufacture motors, pumps and valves. Insulation requirements for maintenance of the pipeline, compressor stations, and plant may be great enough to support local manufacture. Personal services such as banking, real estate, baking, entertainment, medical services, etc. will be required. Finally state and local government will grow in proportion to the growth in population and tax revenues.

2. Other Economic Benefits

   a. Best Use of the Resource

   The development of a possible liquids extraction facility, fractionation plant, and petrochemical manufacturing at a tidewater location promises to maximize the best possible useage of valuable gas liquids. In contrast to other approaches where gas liquids are considered strictly on a

BTU value basis, the TAGS approach provides the potential for processing within the State gas liquids such as ethane and propane for a higher return in the final form of petrochemical byproducts.

b. Source of Gas for Local Consumption

As proposed, the Trans Alaska Gas Pipeline has the potential of supplying a source of natural gas for local consumption. The terminus location of the pipeline could definitely be supplied with natural gas. In addition to this, side valves could be provided at any location along the pipeline route where an economically justifiable need for the gas may exist. It should be pointed out, however, that the raw gas stream as transported in the pipeline is not suitable for utilization as fuel without certain processing.

c. Access to Hydrocarbons

As a result of the proposed project all unprocessed North Slope hydrocarbons would remain inside the state of Alaska, thereby offering the potential for instate petrochemical development. The establishment of hydrocarbon processing offers a wide variety of byproducts ranging from plastics to fertilizers. The instate manufacturing of these byproducts has the added benefit of satisfying local Alaskan markets at a potential savings.

C. Comments on Environmental Aspects

No Environmental Impact Statement (EIS), nor even environmental studies have been conducted for the preparation of this initial report. Cost allowances for future studies have been included in the cost estimates presented in this report.

A few general comments are considered appropriate to this initial study. From the Prudhoe Bay area to a point near Livengood, the pipeline closely parallels the crude oil pipeline and is within an established corridor. No new or surprise elements affecting the general environment along this route would be anticipated to result from this new line. At the Livengood area, the pipeline departs and goes through a basically virgin terrain area to near the railroad siding of Dunbar. The environmental impact in this area must be evaluated in future efforts.

At Dunbar, the pipeline route enters a well established corridor containing the Alaska Railroad and State Highway No. 3. Since this is an established transportation corridor, it is not anticipated that the pipeline will present any significant impact. At a point near Willow, the pipeline again leaves the established corridor and traverses the Point McKenzie general peninsular area which basically can be characterized as a virgin wilderness area. At this point, the pipeline crosses the Cook Inlet to near Point Possession. Although there have been other pipelines in the Cook Inlet, no prior line is in this exact location and it is recognized that future studies must be made to determine any environmental impact. From Point Possession to the Nikishka area, the pipeline would closely parallel existing pipelines. At Nikishka several petroleum plants currently exist and the proposed additional plants will present similar types of operations.

D. Capital Investment

1. Basis

The cost of the pipeline and associated compressor and refrigeration stations for this project has been estimated on a "conceptual design" basis. By definition, conceptual design is based on ideas of both the client and the engineers, experience of similar projects, historical data and partial information. While this initial study presents an estimated cost for a technically feasible plan, it does not include the in-depth design, investigations and optimization studies considered essential to obtainment of project financing. Accordingly, the following facts should be recognized when reviewing the cost estimates:

(1) All costs are based on 1982 conditions without allowance for future inflation.

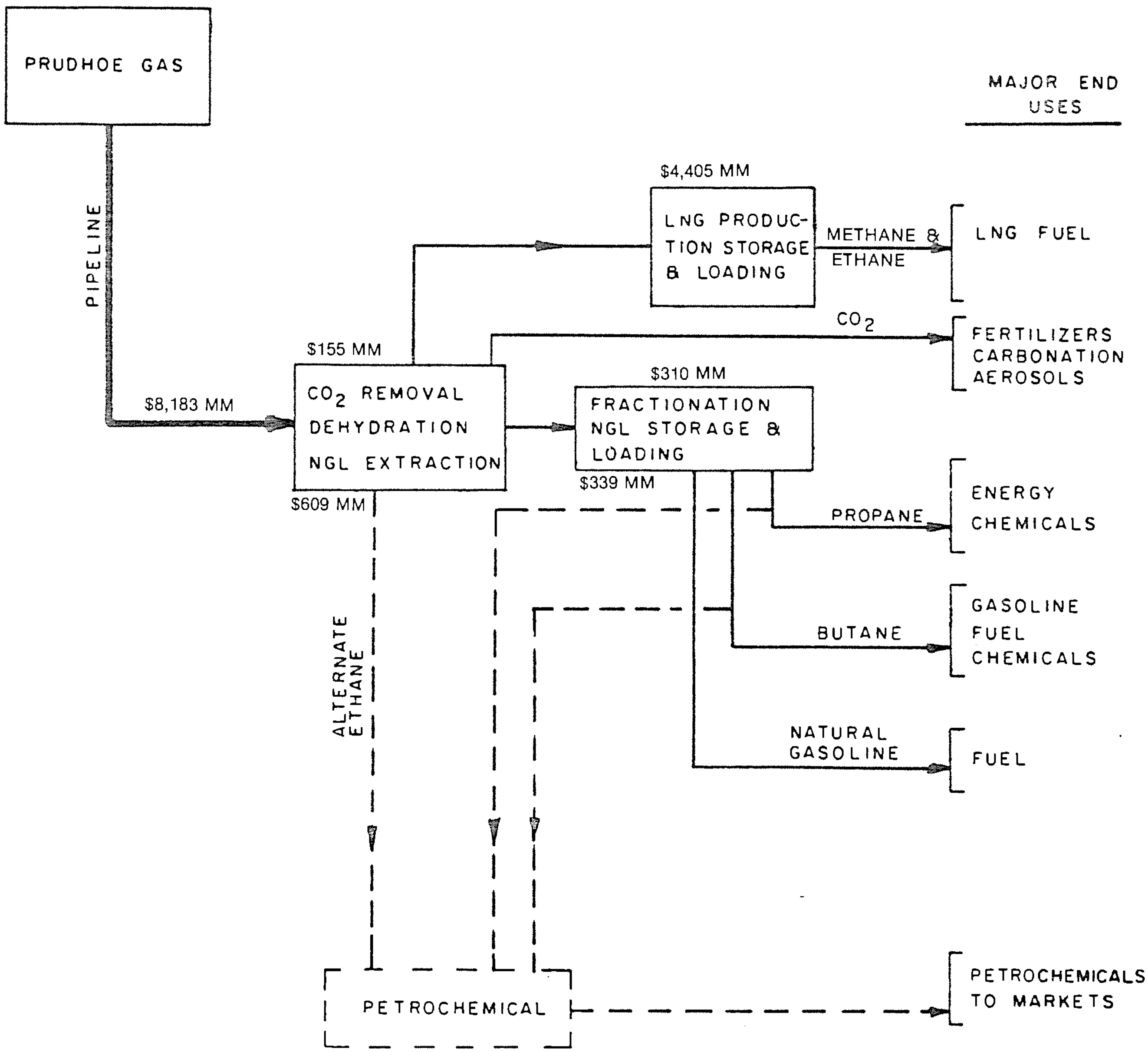
(2) Detail specifications and firm quotations were not utilized; prices are based on recent experience and discussions with suppliers.

(3) Capital and operating costs are based on numerous assumptions, which though considered as valid must obviously be confirmed by more comprehensive studies.

(4) All costs include engineering, project management, and a 20% contingency.

2. Estimates of Capital Cost

CUMULATIVE TOTAL MM $			
	PHASE		
ITEM	I	II	III
PIPELINE, COMPRESSOR STATIONS AND REFRIGERATION	$ 4,548	$ 6,216	$ 8,183
CO_2 REMOVAL	76	117	155
NGL EXTRACTION	302	463	609
NGL FRACTIONATION	147	225	310
NGL STORAGE & LOADING	167	167	339
LNG PRODUCTION & STORAGE	1,640	2,772	4,405
DOCK FACILITIES	193	193	193
ORGANIZATION COST	100	100	100
TOTAL PROJECT	$ 7,173	$10,253	$14,294



ACCUMULATED COST PHASE III

DASHED LINES INDICATES ALTERNATE FEEDSTOCK ROUTE.

SOLID LINES INDICATE UNITS INCLUDED IN THIS REPORT COST ESTIMATE.

Brown & Root, Inc. PIPELINE ENGINEERING HOUSTON, TEXAS

CONT. NO.

TRANS ALASKA GAS SYSTEM
CONSTRUCTION COSTS

DWG. NO. FIGURE II-D

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TRANS-ALASKA GAS SYSTEM:

ECONOMIC ANALYSES

Summary and Conclusions

Introduction

Dillon, Read & Co. Inc. has been asked by the Governor's Economic Committee on North Slope Natural Gas (Committee) to review the prospective economics of the proposed Trans-Alaska Gas System (TAGS or System). The economic analyses undertaken herein examine on an initial basis the prospective economics of the System including the transportation, processing and sale of North Slope gas based on preliminary engineering costs, project design characteristics, marketing information and financial assumptions.

Because the project is expected to be heavily capital intensive, System economics will depend in large part on the costs of the System and the relationship of such costs to the value of North Slope gas sold in the marketplace. Based on the studies of its marketing advisors, the Committee has examined Far East markets, principally Japan, in relation to sales of System liquified natural gas (LNG). For the purposes of the analyses therefore, projected market prices for System LNG have been assumed to parallel projected LNG market prices in Japan.

To identify prospective System costs the economic analyses rely on construction and operating cost projections (in 1982 dollars) of Brown & Root, the Committee's engineering consultant, and on certain economic and financial assumptions developed in conjunction with other Committee advisors. The economic analyses have developed base analyses which estimate prospective capital costs of the project at completion (including inflation, interest and financing costs during the construction period), prospective operating tariffs to cover System costs of delivering and processing gas in South Alaska, and prospective economic values for System LNG measured by the difference between the cost of System LNG delivered in Japan and the prospective market value of the gas in Japan. Prospective System tariffs for System gas products are adjusted to reflect the cost of fuel used in the System's transportation and processing facilities.

Prospective System capital costs and tariffs are based on economic and financial assumptions which reflect the preliminary and limited information on the System presently available. The analyses reflect the large capital investment required for construction, the completion and marketing risks connected with an Alaska gas project, and the special characteristics associated with the System including phased construction, transportation and processing of all gas products, construction of the conditioning facilities in South Alaska, System tariffs related to market forces rather than regulatory principles and potential export markets for System LNG.

Key assumptions made in the base analyses include the Brown & Root construction, organization and operating and maintenance costs, private investor project financing, unregulated System tariffs, Japanese market prices for System LNG, as well as financial assumptions as to capital structure, debt, interest rates, equity returns, inflation, LNG price increases and tax consequences.

The base analyses determine a range of prospective tariffs to reflect current uncertainty as to project risk allocation and required equity rate of return expectations. The lower tariff range reflects a lower rate of return on equity investment (30% after tax) on an assumption of limited equity risk, while the higher tariff range assumes increased equity risks and higher return requirements (40% after tax). All System tariffs have been calculated on a breakeven basis to recover all operating costs, fuel costs, debt service, taxes and return on and return of equity investment.

Although the economic analyses examine and use a number of economic and financial assumptions in order to estimate prospective capital costs and tariffs, the current level of uncertainty as to prospective System sponsors, project risk allocation, purchaser interest in System gas products and final System costs inhibit conclusions as to project financeability at the present stage of review. Since financeability will depend in the final analysis on the agreement between the sellers and the buyers of System gas, the present economic analyses do not purport to present a financial plan or conclusions as to financial viability but present prospective System economic consequences based on assumptions deemed reasonable under current conditions.

In addition, although the economic analyses have relied on cost data provided by Brown & Root, such estimates are subject to revision and reestimation as project design is refined and optimized. Furthermore, the marketing and financial assumptions used in the base analyses are preliminary and also subject to change or modification as System analysis develops and as economic and financial conditions change. For these reasons, the tariff results presented in the following tables should be considered as indicative of order of magnitude and should not be viewed as definitive. In order to gain perspective on System economics and feasibility in a volatile economic environment, the analyses calculate a number of sensitivity cases including cost overruns which illustrate the change in tariffs that would occur as a result of variations in the assumptions used in the base analyses.

The base analyses examine the System on two alternative bases. In its most economic configuration the System would be built in three phases and at full completion would be capable of transporting and processing 2.83 billion cubic feet per day (bcf/d) of raw gas from Prudhoe Bay to a South Alaska port (the Total System). Brown & Root estimate that construction and organization costs of the Total System, including pipeline, conditioning and liquefaction facilities, over a period of nine years would approximate $14.3 billion in unescalated 1982 dollars including a 20% allowance for contingencies.

Because each of the phases of the System would be capable of operating as a discrete entity, a second economic analysis focuses on limited operations from the first construction phase capable of transporting and processing approximately 0.95 bcf/d of raw gas (the Phase I System). Construction and organization costs of the Phase I System over a period of five years are estimated by Brown & Root at approximately $7.2 billion in unescalated 1982 dollars. Potential advantages of building and financing a smaller System as an initial step support a separate examination of the Phase I System.

Prospective System Capital Costs and Tariffs Delivered In South Alaska

The tables below summarize the results of the base analyses in terms of prospective System capital costs at completion and tariffs per unit of gas products delivered in South Alaska. All tariffs are expressed in nominal dollars per million British Thermal Units (MMBtu) in the year that initial operations are expected to commence (1988) and are the same for all gas products transported and processed by the System.

Prospective System Capital Costs

(Millions of As Spent Dollars to Completion)

Total System	$ 25,465 (1992)
Phase I System	$ 11,556 (1988)

Prospective System Tariffs Delivered In South Alaska

(1988 Dollars per MMBtu)

	Lower Tariff Range	Higher Tariff Range
Total System	$ 4.67	$ 6.16
Phase I System	$ 5.94	$ 7.91

Prospective Costs of System LNG Delivered in Japan Compared to Projected Japanese LNG Prices

Based on the projections of the marketing advisors the analyses assume an average shipping cost, including the costs of LNG lost through evaporation in transit (boil-off), of approximately $1.00 per MMBtu in 1988 dollars. The table below summarizes the comparison of prospective costs (tariffs and shipping costs) of System LNG delivered in Japan with projected Japanese LNG market prices (based on projections of Mitsubishi Research Institute) in 1988 dollars and indicates the price differential or prospective economic value of System LNG in Japan.

Prospective System LNG Costs

Delivered In Japan Compared to Projected Japanese LNG Prices
(1988 Dollars per MMBtu)

	System LNG Costs Japan (Lower Tariff)	System LNG Costs Japan (Higher Tariff)	Japanese LNG Prices	Economic Value of System LNG (Lower Tariff)	Economic Value of System LNG (Higher Tariff)
Total System	$5.67	$ 7.16	$ 7.89	$ 2.22	$ 0.73
Phase I System	$6.94	$ 8.91	$ 7.89	$ 0.95	$(1.02)

Prospective System tariffs for NGL products delivered in South Alaska have not been analyzed in connection with Japanese markets but have been converted to the following per-barrel tariff costs for the major NGL products, propane and butane, to provide the North Slope producers a basis of comparison with alternative options of conditioning and transporting NGL products:

Prospective NGL Costs Per Barrel Delivered In South Alaska

(1988 Nominal Dollars)

	Total System	
	Lower Tariff	Higher Tariff
Propane	$ 17.79	$ 23.47
Butane	20.50	27.04
	Phase I System	
	Lower Tariff	Higher Tariff
Propane	$ 22.63	$ 30.14
Butane	26.08	34.72

Conclusions

Total System

The tables set forth on page 6 indicate that under the assumptions used in the base analyses, including projected market prices of LNG in Japan, Total System LNG could be expected to compete in the Japanese market and be capable of covering System costs and shipping costs. Additionally, the tables also indicate a range of prospective economic values for Total System LNG, adjusted for fuel costs, of between $2.22 and $0.73 per MMBtu in 1988 dollars.The projected economic values reflect the excess of market prices over the costs of System transportation and processing. The relatively significant economic value in the lower tariff range, $2.22, supports an inference as to economic feasibility. On the other hand, the higher tariff range reflects a case which, if the higher equity return is required by investors, results in relatively little economic value, $0.73, to the gas. This economic value could be further eroded if construction costs were to escalate. In the case of a 30% cost overrun in the higher tariff case, the economic value of the gas would decline to a negative ($0.86) per MMBtu which indicates that although the System could service its debt it would not be able to achieve the higher equity return in the market place.

However, several sensitivity cases examined in the analyses could, if implemented, significantly improve the economics of the Total System even in the higher tariff case. Sensitivity assumptions which could reduce System tariffs and increase economic values include stretching out System debt repayment over the life of the System on a level sinking fund basis, potential State of Alaska tax exempt financing of the liquefaction facilities and expensing interest costs for tax purposes rather than capitalizing them during the construction period. If it were possible to implement these sensitivity cases, the economic value of the gas could be increased from $0.73 in the higher tariff case to approximately $2.16 per MMBtu. More precise analysis of the Total System's economic feasibility, at least in the higher tariff range, must, necessarily, depend on more detailed study of these alternative approaches.

Phase I System

The projected economic value of gas in the Phase I System range from $0.95 in the lower tariff case to a negative ($1.02) per MMBtu in the higher tariff case. The positive value in the lower tariff range supports an assumption as to competitiveness of the gas in the marketplace as well as providing some economic value. However, if the higher equity returns are required the gas would not appear to be competitive. Although the Phase I System might be economically improved to the extent that level debt service or other sensitivity analyses discussed above were available, the effect would probably not be sufficient to make the Phase I System, standing as a discrete economic project, more than marginally economic. The Phase I System might, however, be an acceptable first step construction and financing approach if prospective sponsors determine that the Total System at completion has the potential for attractive economics or that other potential project benefits might accrue to participants.

Economic Analyses Discussion

TAGS Proposal

The Brown & Root proposal for TAGS is an all-Alaska natural gas transportation and processing system. The System contemplates the pipeline transportation of untreated North Slope gas to South Alaska where conditioning and liquefaction facilities would be constructed to treat the gas. The System is expected to consist of the following three principal components:

1) 36 inch diameter pipeline with compression stations, extending from the North Slope gas fields to a tidewater port in South Alaska (the pipeline);

2) conditioning facilities at the terminus of the pipeline to remove carbon dioxide (CO_2) and to extract and fractionate the NGL contained in the gas (the conditioning facilities); and

3) liquefaction facilities also at the South Alaska port to liquefy the LNG for export (the liquefaction facilities).

The Committee has not requested Brown & Root to review additional facilities that will be required outside Alaska.

Phased Construction

Brown & Root has analyzed a three phase schedule for the construction of the System. In the initial phase, construction would extend over a five year period, including a two year study and permitting period, and the

System would be capable of transporting and processing approximately .95 bcf of gas products per day. A second and third phase would expand System capacity by the installation of increased compressor capacity. Construction of the second phase would require an additional two years and would be capable of handling approximately 1.75 bcf/d at completion. The third phase would require a further two years of construction with capacity of approximately 2.83 bcf/d. The total design and construction period through all three phases, therefore, would be nine years. This construction period could be accelerated if phasing were eliminated.

System Component Costs

Brown & Root has estimated on a preliminary basis the construction and organization costs including contingencies, and the operating and maintenance expenses, of the System on an unescalated basis in 1982 dollars. The estimated costs include North Slope refrigeration, pipeline transportation, CO_2 removal, extraction and fractionation of NGL products and the liquefaction of the gas into LNG.

Estimates of construction, organization and operating and maintenance costs are aggregated under the three principal components of the System - the pipeline, the conditioning facilities and the liquefaction facilities (the System components). The construction and organization cost estimates for the System components in 1982 unescalated dollars, including a 20% contingency amount, are summarized for each of the construction phases on a cumulative basis as follows:

Estimated Cumulative Construction and Organization Costs In 1982 Dollars (Millions)	Phase I	Phase II	Phase III
Pipeline	$4,608	$ 6,276	$ 8,243
Conditioning Facilities	702	982	1,423
Liquefaction Facilities	1,863	2,995	4,628
Totals	$7,173	$10,253	$ 14,294

The projected costs do not include estimates of inflation or financing costs during the construction period, the cost of shipping or facilities outside Alaska. The Brown & Root proposal is at a preliminary stage and changes and modifications can be expected in their estimates if they continue to refine, verify and modify their initial projections.

Brown & Root has also provided the following estimates of operating and maintenance expenses (before System fuel costs which are included in the tariff as a cost adjustment) on a cumulative basis in unescalated 1982 dollars:

Estimated Cumulative Operating and Maintenance Expenses In 1982 Dollars (Millions)	Phase I	Phase II	Phase III
Pipeline	$ 20	$ 35	$ 49
Conditioning Facilities	19	27	39
Liquefaction Facilities	39	66	105
Total	$ 78	$ 128	$ 193

Estimated construction, organization and operating and maintenance costs and the projected spending schedule are set forth in Exhibit A.

System Characteristics Affecting Economic Analyses

The proposed TAGS project contains a number of characteristics which affect economic evaluation and analysis. Certain of the major characteristics are general to all North Slope gas projects while others are special to the System and evolve from the design of the TAGS proposal. Among these System characteristics are the following:

General System Characteristics

The System, similar to any other North Slope gas project, will face significant hurdles in order to satisfy existing and prospective laws, regulations, expectations and requirements of the large number of parties, institutions, agencies and governments which must necessarily be involved. Apart from such fundamental problems as environmental factors and political issues involving the production, transportation, processing and sale of North Slope gas, at least three inherent project characteristics can be expected to affect and determine System economics:

Project Size. The proposed System represents an enormous undertaking within the private sphere in terms of physical and financial scope. The total amount of capital, both debt and equity, which will be required to complete the project, and the extended time period over which construction costs will be expended, will undoubtedly place substantial strains on any group of investors. Capital availability in the magnitude contemplated could, under circumstances similar to those which capital markets have experienced in recent years, be problematical. In any event, the costs of such capital can be expected to be substantial to reflect the risks to investors inherent in a project of the size and scope of an Alaskan gas project.

Completion. Due to the large anticipated construction costs, investors will be concerned, as they have in all predecessor projects, about project completion. Other large construction projects have underscored investor concerns with respect to completion. Debt and equity capital will only be available if investors develop confidence that construction costs do not present significant risks of extensive cost overruns or that cost overruns can be provided by responsible credit sources and that the System will be able to function within design parameters. Completion, therefore, constitutes a significant project risk in connection with System economics.

Marketing. Marketing considerations from an economic perspective include both the capacity of the market place to absorb new supply and the price of the gas products at which such demand will materialize. Prior to investment, investors must have reasonable assurances that market demand will exist for the large volumes of gas associated with the System. In addition, gas tariffs cannot be so high that they result in project gas prices which are uncompetitive. As a result of the large anticipated construction costs, a North Slope gas transportation and processing project will be capital intensive and project costs will absorb a significant portion of the value of the gas in the marketplace. Investors must have assurances that the gas products will be competitive and that revenues will be generated to meet project costs and repay capital investment. Marketing risks have been heightened recently due to general world recession, energy conservation efforts, general price weakness in hydrocarbon products, large world gas supplies and gradual natural gas price decontrol in the U.S.

Special System Characteristics

In addition to these general characteristics which have economic and financial implications common to all Alaska gas projects, the System also has a number of special characteristics arising from the System's proposed design which affect System economics. These special characteristics include the following:

Phased Construction. Construction of the System under a three phase approach contemplates completion in stages with the following potential advantages:

1) the ability to transport and process gas at an earlier date;

2) the generation of revenues and tax savings from limited operations in the first and second phases which could provide substantial funds to the System prior to final completion;

3) the build up in System gas volumes on an incremental basis to better match prospective market growth and demand in export markets; and

4) the option to demonstrate the viability and economics of a smaller first phase project prior to commitment to a full scale System.

Transportation of Raw Gas Products. The TAGS proposal contemplates transportation of raw untreated natural gas as it is produced rather than building conditioning facilities on the North Slope and treating the gas before injection into the pipeline. The System, therefore, proposes to ship the raw gas containing a mixture of CO_2, heavy natural gas liquids and methane and ethane gases. As in a gas gathering pipeline, the System proposes to extend the North Slope wellhead to tidewater in South Alaska where the untreated gas will be available for conditioning and processing.

Transporting gas containing substantial quantities of CO_2 (approximately 12 1/2%) will penalize the pipeline by using pipeline capacity for a product which has little or no Btu content and whose value is presently undeterminable (it may be possible, however, for the low Btu CO_2 to be used as fuel for power generation in South Alaska or for injection into Cook Inlet producing fields to enhance hydrocarbon recovery). On the other hand, the volume capacity lost by transporting CO_2 is more than made up by the high compression transportation of NGL products which have Btu content per cubic foot substantially in excess of the methane and ethane gases as well as enabling conditioning in South Alaska. On a blended basis, covering all gas products transported, the total Btu content of the System is increased by approximately 5% as compared to a pipeline which would solely transport methane and ethane products.

Elimination of Alternative NGL Transportation. System design which transports all gas products in one pipeline avoids multiple pipelines or alternative transporation and processing systems. By transporting the NGL products through the System's pipeline it is possible to avoid the financing and construction of a separate liquids pipeline or an alternative transportation and processing system for NGL removed and conditioned on the North Slope.

Conditioning Facilities in South Alaska. Pipeline transportation of all gas products allows conditioning of the products on the South Coast of Alaska. Construction of the conditioning facilities including the gas treating plant to remove the CO_2, and the extraction, fractionation and loading and storage facilities for the NGL, on the South Coast is expected to result in substantial construction and operating and maintenance cost savings as compared to North Slope construction and operation.

Shared Cost Savings. The potential cost savings resulting from the integrated nature of the System's design enabling common transportation and South Alaska conditioning and liquefaction is shared by all System gas products and not just the methane and ethane products.

Potential Markets. System LNG and NGL products would be available in South Alaska for shipment to markets. Shipping costs, however, will significantly affect the costs of System products, and from an economic perspective the natural markets, at least for LNG products, could be expected to be the Far East, principally Japan, and the West Coast of the United States. Demand for LNG in Japan has provided higher price levels for natural gas than in the U.S. In addition, Japanese political and economic policies have promoted the importation of LNG products in substitution for crude oil imports. As a consequence, System LNG output could be expected in the first instance to be directed towards the Japanese market as well as the markets of other industrialized Pacific rim nations. These markets will also be subject to competition from other Pacific area gas producers. Exports of Alaskan natural gas to Japanese or other foreign markets will require the political support and approval of the U.S. government.

Regulation. The legal advisor to the Committee, Birch, Horton, Bittner, Monroe, Pestinger and Anderson, believe that a project which transports and processes gas solely in Alaska and exports gas products to foreign markets may be exempted from the purview of the Natural Gas Act insofar as pipeline tariffs are concerned. It is believed, therefore, that exportation of gas may result in a minimum of federal regulation.

The absence of Federal Energy Regulatory Commission (FERC) ratemaking authority in connection with the System would mean that the System would not have the benefit of the regulatory procedures and authority for passing on mandated price levels in the form of tariffs for its gas products to consumers. Conversely, absent such regulations, the System would not be constrained by regulated maximum tariffs and could negotiate tariffs which reflect the System's economic value in the market place rather than its historic costs. Under any circumstances, however, the jurisdictional nature of the System will have a major impact on System economics and must be determined at an early stage.

While the legal advisor believes that, absent FERC regulation, the System may need a certificate of public convenience and necessity from the

Alaska Public Utilities Commission for construction of the pipeline component, State rate making authority over gas exports will probably not be required.

Ownership of Gas Products. The transportation of raw gas from the North Slope and processing in South Alaska into component products could allow the producers to own System gas throughout all stages of the System to tidewater or beyond.

System Components. The divisable and discrete nature of each of the System's three components-pipeline, conditioning facilities and liquefaction facilities-could provide operating and financial options to the System. Components could be separate entities owned and operated by the same or different sponsoring investors. Independent component entities could delineate jurisdictional issues should they arise. Additionally, separate component financing could provide a degree of flexibility which might enhance System financing subject to the limitation that all components must be financed on a basis to insure timely System completion. Component financing might better reflect the allocation of ownership and financing obligations between parties with different System interests. Divisible components could reduce the magnitude of the financing each participating group would be responsible for, expand the total investment capital made available to the System and potentially reduce the costs of such capital. Examples of component financing include Japanese purchaser financing and/or State of Alaska financing in connection with System component facilities.

Possible State of Alaska Participation. It may be possible for the State of Alaska to participate in System financing through the issuance of tax exempt revenue bonds in connection with the liquefaction facilities. Under Section 103 (b) of the Internal Revenue Code a State port authority is authorized to finance certain dock, wharf and storage facilities by the issuance of tax exempt revenue bonds. State financing of the liquefaction facilities might be analogous to the tax exempt financing of port facilities by the City of Valdez in connection with the oil pipeline. State financing of the liquefaction facilities could contribute to System economics by providing new sources of capital, reducing equity investment in the liquefaction facilities and reducing the cost of debt financing.

It is uncertain, however, whether existing federal tax law permits such financing and the ability to implement tax exempt financing in connection with the liquefaction facilities may depend upon future interpretations or modifications of the tax laws. A revenue ruling from the Internal Revenue Service would undoubtedly be requested. It is also currently unknown whether the State of Alaska would be willing or would have the authority to issue such debt under existing statutory authorization.

Additional Study Necessary for Financing Plan

The general and special characteristics of the System discussed above have a significant bearing on System economics and have, to a large extent, shaped the economic and financial assumptions used in the economic analyses. Should System analysis proceed, each of the System's characteristics would have to be subjected to an extended and in depth study where they would have to be tested and proven to the satisfaction of all potential participants in the project. Additionally, even though the System's special characteristics might provide specific advantages, the general characteristics of any North Slope gas project - large construction costs, extended construction period, frontier pipeline construction conditions, possible environmental and political intervention, as well as non-completion and marketing risks - may still preclude System financing. The development of a feasible financing plan requires further study of the relatively unique delivery design of the System, of gas markets, of potential System sponsors and the design of a project structure which addresses the amounts and kinds of risks investors are willing to bear commensurate with expected returns.

Objective of System Economic Analyses

Based on the general and special characteristics inherent in the TAGS proposal, economic analyses of the System have been undertaken in order to determine on an initial and preliminary basis the potential economics of transporting and processing North Slope gas through the System. The analyses examine the prospective economics of the System as an independent transportation and processing project and does not attempt to measure other potential benefits which might occur as a result of System operations and ownership.

The objective of the economic analyses is to determine on a preliminary basis the prospective costs of transporting and processing System gas and the prospective economic value of System gas measured by the difference between System costs and the value of the gas in the market place. Prospective System costs are determined by using Brown & Root's preliminary estimates of organization, construction and operating and maintenance costs calculated in unescalated 1982 dollars to determine prospective capital costs and a range of prospective tariffs for the three principal components of the System inclusive of estimated inflation and financing costs.

Prospective capital costs of the System represent total construction and organization costs projected by Brown & Root adjusted for assumed inflation and financing costs during the construction period. Prospective capital costs represent the amount of invested capital that would be required to finance the System.

Prospective System tariffs represent the total estimated costs of transporting and processing System gas products delivered in South Alaska on a unit of gas basis. Tariffs include operating and maintenance expenses estimated by Brown & Root adjusted for inflation, System fuel costs, income taxes and the costs of servicing invested capital including the payment of interest and principal on debt and the payment of return on and the return of equity investment.

Prospective System tariffs in South Alaska can be used as a basis for evaluating System costs at the port of embarkation or, alternatively, can be evaluated in relation to specific markets of sale. In the case of System LNG, a comparison of prospective System LNG tariffs and shipping costs to Japan with forecasts of LNG prices in the Japanese market has been made in order to determine potential competitiveness of System LNG and its prospective economic value in the Japanese market. NGL tariffs, on the other hand, have been converted to costs per barrel delivered in South Alaska.

Assumptions for Base Analyses

In determining prospective capital costs and tariffs the economic analyses rely on a number of assumptions which reflect the nature of the System and its currently perceived risks. These assumptions are based in part on an evaluation of the System's general and special characteristics previously discussed. The assumptions used to determine the base analyses are reviewed herein and form the basis upon which System prospective capital costs and tariffs are determined. While the assumptions used in the base analyses are helpful in testing and measuring System economics they should not be viewed as definitive. Any economic analysis of a prospective project has certain inherent limitations which include possible changes in project costs, marketing, tax and financing conditions which could affect, both positively and negatively, the assumptions used to determine project costs and tariffs. The base analyses present estimates of what could happen assuming certain costs and economic circumstances. They do not represent a forecast of what will occur. Indeed, a variety of alternative assumptions were applied in the sensitivity analyses and their effects on System economics are discussed herein. Nevertheless, the base analyses reflect reasonable capital cost and tariff estimates given the preliminary stage of System design and review.

Included among the assumptions used in the base analyses are the following:

Brown & Root Cost Estimates

The Brown & Root estimates of construction and organization costs and operating and maintenance expenses in unescalated 1982 dollars set forth in Exhibit A have been used in the base analyses. The cost estimates do not provide for inflation or financing costs during construction. Because the construction period extends over a number of years and inflation and financial costs can be expected to substantially increase the estimates, the base analyses develop the prospective inflation and financing costs of the System.

Any substantial change or modification in the Brown & Root cost estimates would, of course, significantly affect projected System capital costs and tariffs. Because of 1) the preliminary nature of the Brown & Root cost figures, 2) the limited time period in which they were prepared, and 3) the possibility of slippage in the proposed study and construction period time schedule, the financial evaluation further considers a sensitivity case which assumes a 30% construction cost overrun. Because of the 20% contingency amount already included in the Brown & Root estimates, the total overrun amount in the sensitivity analyses would approximate 56% of original cost estimates.

Total System and Phase I System

Brown & Root has proposed one System constructed in three separate phases over a period of nine years. The economic analyses however, examine two cases. The first analysis, the Total System case, assumes the full capacity three phase project constructed over a nine year construction period and a twenty year operating period as estimated by Brown & Root. The Total System case assumes that partial operations will commence in the 6th year when the first phase is completed and gas deliveries begin, and is stepped up in the 8th year when the second phase is completed, with full capacity in the tenth year.

A second case is also analyzed which assumes that only the first phase is financed and built and the capacity is limited to .95 bcf/d of gas, the Phase I System. The Phase I System assumes a 5 year construction period followed by a 20 year operating period. A Phase I System is examined because of the advantages of arranging financing for a substantially smaller system which would, nevertheless, be capable of transporting and processing substantial amounts of North Slope gas. Although capital costs and operating and maintenance expenses can be expected to be significantly lower in the Phase I System, tariff costs on a unit of gas basis can be expected to be higher because of the greater proportion of fixed costs borne by fewer units transported. The economic analyses develop prospective capital costs and tariffs under both systems to test their economics in the market place. Each case, therefore, is examined for the purposes of the economic analyses as an independent system.

System Components

The economic analyses for both the Total System and the Phase I System determine prospective capital costs and tariffs for each of the System components:

1) pipeline
2) conditioning facilities
3) liquefaction facilities

The aggregate of all component costs and tariffs represents total System costs and tariffs.

Gas Product Costs on a Btu Basis

System engineering proposes an aggregate of component facilities which will transport untreated North Slope gas products and process them in South Alaska into marketable products ready for sale and shipment. Although analyzed in terms of separate components the System is one integrated project which relies on the performance of all System components to complete the chain of transporting and processing the gas products into saleable commodities. For purposes of the analyses, therefore, the System has been regarded as one integrated project in which potential cost penalties and cost savings generated by System design are shared equally by all gas products on a Btu basis.

Japanese Markets, Shipping Costs and LNG Prices

The Committee has received and reviewed marketing studies from a number of Japanese advisors. Discussion and conclusions based on these marketing studies have been included in the marketing section of this report. The marketing advisors have advised that Japanese demand for LNG will grow from the 1982 level of approximately 17 million tons per year to approximately 28 million tons in 1985 and between 37 and 42 million tons in 1990 (MITI, a Japanese governmental agency, estimates Japanese demand in 1990 at 43 million tons). To fill the gap between these projected demand levels in 1990 and current supplies, Japanese users have completed or are in discussions on new contracts with LNG suppliers in Australia, Indonesia, Thailand, Malaysia, Qatar, Canada and the U.S.S.R.

System volume is expected to total approximately 5 million tons in 1988 and to grow to approximately 14 million tons by 1992. Although the Committee believes that the Japanese market will have the potential capacity to absorb a major portion of System LNG, the System must actively compete at an early stage with other sources of supply to ensure timely System LNG sales. The Committee does not assume at the present time, therefore, that the Japanese market will, in fact, absorb System LNG. This conclusion can only be determined after negotiation between owners of the gas and potential gas purchasers and will depend in part on the attitude and support of both the U.S. and Japanese governments. However, because of this potential Japanese market the base analyses have analyzed System LNG, constituting over 80% of the Btu content of System gas products, in relation to the Japanese markets and for analytical comparison the analyses assume the transportation to and sale of LNG products in Japan at projected Japanese LNG prices.

Transportation costs to Japan assume estimated shipping costs as determined by the Committee's shipping advisors. Shipping costs assume the construction and financing of a new LNG tanker fleet in Japan and include the boil off of System LNG in shipment. Although one of the Committee's marketing advisors considers that the boil off LNG could be used as ship fuel this has not been assumed for the purposes of the analyses. Estimated shipping costs in 1988 dollars are assumed to approximate $1.00 per MMBtu.

The Committee's marketing report relies on Mitsubishi Research Institute's (MRI), one of the marketing advisors, estimates of future LNG prices in Japan. The MRI projections assume LNG price parity with imported crude prices in Japan and are projected to increase from the $5.90 level in 1982 to approximately $7.89 per MMBtu in 1988, the first year of System operations. This price growth represents a 5% compound growth rate over the period. MRI projects a compound annual rate of increase of 7% thereafter. Unlike other recent projections of world oil prices which assume real price increases over general inflation rates, MRI forecasts a decline in real prices of LNG between 1982 and 1988, as compared to their own inflation assumptions and the 7% inflation rate assumption used in the analyses. Estimates of LNG prices by other marketing advisors were somewhat higher than the MRI projections and included forecasts of real LNG price increases.

Unregulated Tariff Rates

Based on the advice of the legal advisor it has been assumed for the purposes of the base analyses that because prospective markets for System LNG may be international export markets, primarily Japan, System tariffs will not be regulated by the FERC. In addition, it is also assumed on the advice of the legal advisor that although the Alaska Public Utilities Commission may have jurisdiction to issue a certificate of convenience and public necessity to construct the pipeline, it will not have or exercise jurisdiction over System tariffs. Tariffs, therefore, for purposes of the analyses are not based on rate base principles involving historical costs. It is assumed that tariffs will be negotiated in transportation and processing agreements between the System and the owners of the gas products and will reflect both prospective System costs and the potential market value of the gas products.

Private Investor Project Financing

The base analyses assume that the System will be financed by private investors in a project financing. Private investor project financing contemplates the creation of a new entity to finance, contruct, own and operate the System's component facilities. To effect a project financing, it is generally necessary for the new entity to secure contractual commitments for funds at least equal to the estimated cost of the project prior to the commencement of construction. Estimated costs must provide for adequate construction cost contingencies and for inflation and financing costs during the construction period. Commitments are secured from project sponsors in the form of equity capital and from lenders in the form of debt capital.

Project financing contemplates that the project entity will complete the project and that the project will be self-sustaining in that future estimated revenues will be adequate to cover operating costs including the cost of debt and equity capital invested. Project revenues are usually assured by long term contracts with users who agree to pay a tariff or fee for the use of project facilities.

In the case of the System, the use of the component facilities will be offered to owners or purchasers of the gas products (shippers) for the purpose of transporting and processing the gas products. The System may enter into separate transportation and processing agreements with each of the shippers whereby the System will accept the untreated gas, transport and process it, and deliver the constituent gas products to the shippers in South Alaska. It is not assumed that the System will take title to or own the gas at any stage of the process. The shippers' obligation will be to supply the gas at the North Slope, to take delivery of the gas products in South Alaska and to pay the tariff costs for transporting and processing the gas.

As discussed previously the size and nature of any North Slope gas project raise significant questions as to completion and marketing risks. Potential lenders and equity investors will assess these risks before committing funds. Lenders will most likely insist on extra-System credit support in the form of assurances of completion by parties capable of performing, take- or-pay transportation and processing contracts, and/or guarantees of project debt by parties who are perceived by lenders as having sufficient credit to perform such obligations in the event it becomes necessary.

Therefore, from an analytical perspective, the issue will not be whether System completion and revenue assurances are necessary but rather from which parties they will be obtained. Project financing enables potential System support from parties other than System equity sponsors. Project financing can allocate risks between various parties on the basis of their interest in the System and their degree of participation.

Although it is currently unknown who potential equity sponsors of the proposed System may be, it is known which parties have or may have a direct interest in System completion. These parties include:

1) Potential Purchasers of System Gas Products - in Japan and elsewhere who may wish to diversify their sources of supply and to procure firm commitments for long term gas supplies at contracted prices from a politically secure area,

2) the North Slope Gas Producers - who may realize additional wellhead income from gas sales and enhance oil recoveries by the production of the gas,

3) the State of Alaska - both as a royalty owner of the North Slope gas and the recipient of substantial tax revenues and economic benefits from System construction and operation,

4) Other Governmental Entities - principally the Japanese government, which share the objectives of potential Japanese gas purchasers in securing stable sources of gas supply as well as contributing to balanced trade relationships.

5) Major Contractors and Suppliers - which would be interested in designing and building the component facilities or providing material and equipment, and

6) Export Financing Institutions - of nations who competitively seek projects such as the System to encourage national exports.

To the extent that project risks are assumed or accepted by financially capable parties who may have an interest in System completion but who are not necessarily equity investors, the risks of equity investment are moderated and rate of return expectations may be reduced. On the other hand, where equity investors are required not only to risk their equity investment but also provide other undertakings, they assume greater risks and may or may not be willing to provide such commitments.

Although project financing offers the potential to allocate project risks and provide debt leverage there can be no assurances that project financing can in fact be accomplished in connection with a project of the size and risk of the System. In order to accomplish a private financing it may be necessary for those parties with direct and significant interests in the gas and which will be most benefited by System operation, namely, the owners of the gas, the purchasers of the gas and other governmental entities in Japan or elsewhere, and the State of Alaska, to provide financial and investment assistance.

Although the base analyses focus on private investor financing, the analyses also evaluate the effects of State of Alaska participation in connection with tax exempt bond financing for the liquefaction facilities. The results of this analysis are set forth under the various sensitivity analyses undertaken to determine the effects on potential System tariffs.

Rates of Return on Equity

Assumptions as to equity rate of return requirements evolve from risk analysis. The more risk equity sponsors are expected to assume the higher the rate of return required. However, as previously discussed, project financing is capable of allocating certain of these risks between sponsors and other participating or interested parties. Because the precise nature and extent of the equity risk cannot be determined at the present time, the required rate of return is not clearly demonstrable.

The base analyses, therefore assume a range of rates of return which reflect in a general manner the range of risks that might be incurred by equity investors. The lower rate of return range reflects a System financing which limits equity holders' risk to actual equity investment and allocates completion assurances and debt repayment obligations to a wider group of participants and interested parties. The higher rate of return range reflects a System with somewhat greater risk on sponsors in connection with completion and debt assurances. However, since it may be unlikely that any group of private equity investors would accept total risk of System completion and debt repayment neither the lower or the higher rate of return necessarily assume full completion or debt repayment obligations by equity sponsors.

The rate of return range represents the lower tariff case and the higher tariff case in the base analyses. The rate of return in the lower tariff case represents a 30% after tax return to equity investment while the return in the higher tariff case represents an after tax return of 40% (the higher tariff case represents an after tax return on total capital invested including debt and equity of approximately 15%).

Return on equity is calculated on a discounted cash flow basis which discounts at the required rate of return all projected cash flows available for equity to a zero present value. Cash flow available for equity includes all prospective net income of the System, investment tax credits and tax savings accruing from accelerated tax depreciation as discussed below.

Prospective rates of return are calculated only on the basis of equity investment in and equity return from System investment and do not reflect potential return that might be generated by the owners of the gas from gas sales or from enhanced North Slope oil recoveries resulting from production rather than reinjection of North Slope gas.

Tax Savings/Deferred Taxes

Various federal and Alaska tax savings are assumed to be generated at the equity sponsor level over the life of the System and represents cash flow available to equity. These include organization expenses and property taxes deductible for tax purposes during the construction period and available investment tax credits. The Tax Equity and Fiscal Responsibility Act of 1982 contains language requiring the capitalization of interest during construction of certain types of property unless specifically exempted. Although it is uncertain whether the System might be exempted from capitalizing construction interest expense during construction, interest has been capitalized rather than deducted for purposes of the base analyses. To the extent that it is determined that construction interest can be immediately deducted for tax purposes additional tax savings could be generated. A sensitivity case has been calculated to show the effects of expensing construction period interest.

Tax savings generated at the sponsor level during the construction period are assumed available for construction costs. After operations commence, accelerated depreciation deductions on capitalized costs are available to sponsors as provided by the Economic Recovery Tax Act of 1981 as modified by the 1982 Act including reductions in the asset basis for 50% of investment tax credits. 100% of capital costs including capitalized interest costs during construction are assumed to qualify for 5 year tax depreciation. Based on discussions with the Committee's tax and accounting advisor, 5 year depreciation recovery has been assumed for the pipeline component on the assumption that tariff rates will not be established by regulatory procedures and the pipeline should not be a gas utility trunk pipeline. Nevertheless, a sensitivity analysis has been calculated assuming a ten year depreciation period for the pipeline.

Estimated tax savings from the System will be large and will represent a substantial source of cash flow in the early years of operations. To achieve the estimated tax savings equity sponsors must be capable of utilizing such benefits on a timely basis or such benefits must be transferred to third parties under prospective tax and leasing provisions of the 1982 Tax Act. There is, of course, no assurance at this time that sponsors will be capable of using these tax benefits as generated or of transferring them for value.

General Inflation

It is assumed that prices in general will continue to move upward during both the System's construction period and operating period. Inflation, therefore, will have a considerable impact on the System and its economics. Brown & Root estimates that general inflation in Alaska during the construction and operating periods will range between 6 and 8%. For purposes of determining System construction and operating costs the analyses assumes a 7% inflation rate throughout the construction period and the operating life of the System.

Tariff Price Path

Prospective System tariffs will be expected to provide revenue to meet all System costs. For purposes of the base analyses the System's tariff is assumed to escalate on a price path parallel to increases in LNG prices in Japan. As projected by MRI, LNG prices in Japan are projected to increase at 5% per year to 1988, and at 7% per year thereafter. This reflects a decline in real prices to 1988 and no real price increase after 1988 as compared to the 7% inflation rate assumption used in the economic analyses.

The initial System tariff in 1988 is assumed to be that tariff which, given the assumed tariff price path, will yield a stream of revenues sufficient to cover inflating operating costs and to provide a return of and return on capital investment.

Capital Structure

It has been assumed for purposes of the economic analyses that the proposed capital structure of the System and its components will consist of 75% debt and 25% equity. Significant debt leverage is traditional in pipeline financing and enables the project to reduce the total cost of capital by using tax deductible interest. Equity and debt funds are assumed invested on a pro rata basis. It has also been assumed that the debt/equity relationship will remain at the 3/1 ratio throughout the life of each case analyzed.

Modification of the initial capital structure reducing debt and increasing equity investment significantly increases costs and prospective tariffs. On the other hand, deferral of debt repayment on a level sinking fund basis rather than retiring debt early to maintain a 3 to 1 debt to equity ratio, decreases costs and prospective tariffs. Both potential changes in assumptions have been analyzed in the sensitivity analyses.

Debt Interest, Maturity and Average Life

The economic analyses assume that debt interest costs will equal 14% over the life of the System. This reflects a real interest cost of 7% over the estimated 7% inflation rate used throughout the same period. Financing costs have been assumed to constitute 1% of the principal amount of debt financed.

Both the Total System and the Phase I System assume various maturities of outstanding debt up to a maximum of twenty years after completion. Debt amortization is assumed to commence in the first year of operations which is the sixth year in both cases. During operations available cash flow after operating expenses and taxes is applied to debt amortization and repayment of equity so as to maintain a constant debt/equity ratio of 3/1.

As a result of accelerated depreciation in the early years of operation, debt amortization is not on a straight line basis and surplus cash retires debt rapidly. Approximately two thirds of total debt is repaid by the end of the first five years of operation providing an average life for System debt of approximately seven years after completion.

Depreciation

Depreciation for book purposes is computed on a straight line basis assuming a twenty year life.

Income and Property Taxes

A composite income tax rate of approximately 51% reflects Federal taxes at 46% and deductible Alaska income taxes at 9.6%. Property taxes are assumed to be 2% on depreciated book value except for the liquefaction facilities which under current Alaska law are assumed exempt from State property taxes but subject to local borough taxes of 4/10th of 1% of book value.

Throughput/Fuel Usage

Throughput represents the net amount of gas products that are expected to be transported and processed by the System in terms of Btu content after allowing for shrinkage and System fuel usage. Each cubic foot of North Slope gas put through the pipeline is expected to equal approximately 1,055 Btu's on the basis of the average Btu content of each gas product transported in the pipe line. Full capacity throughput has been assumed in the base analyses for the Total System as a result of Brown and Root and the Committee Staff's discussions with the Alaska Oil & Gas Conservation Commission and certain of the North Slope producers.

It is anticipated that a significant portion of System gas products will be used as fuel to operate the component facilities. Brown & Root estimates that approximately 12.2% of the total Btu content of the System will be lost to System fuel consumption in the Total System and 8.5% in the Phase I System. Although the estimated fuel requirement is an aggregate figure for the total System and does not necessarily reflect the same percentage in each component facility the shrinkage adjustment made in calculating component tariffs has been allocated equally between the component facilities.

Estimated System gas input on the North Slope, fuel usage and System throughput in MMBtu's per day under each case is set forth below:

Estimated System Gas Input,
Fuel Usage and Throughput In MMBtu's Per Day

	Gas Input Volume MCF/d	Btu Content (Btu/cf)	Gas Input MMBtu/d	Fuel Usage MMBtu/d	Throughput MMBtu/d
Total System	2,830,000	1,055	2,986,000	365,000	2,621,000
Phase I System	950,000	1,055	1,002,000	85,000	917,000

Although the liquefaction and conditioning facilities will not operate 100% of the time due to anticipated repair and downtime they, nevertheless, will be designed with capacity and storage facilities to process 100% of the pipeline's annual throughput during their operating periods.

System Life

It is assumed that the life of each case analyzed will consist of the construction period plus twenty years of operation. Therefore, System life of the Total System will be twenty-nine years and of the Phase I System twenty-five years.

Working Capital

Brown & Root estimates that working capital requirements in 1982 dollars in all phases will approximate $10 million in connection with the pipeline, $5 million in connection with the conditioning facilities and $25 million in connection with the liquefaction facilities. These amounts are escalated with general inflation and are recovered at the end of System life.

Base Analyses Capital Costs

Using the Brown & Root unescalated System construction and organization costs and applying the assumptions used in the base analyses, the estimated inflation and financing costs during construction of each System component have been developed for both the Total System and the Phase I System. These costs represent the System's estimated capital costs and are set forth in Exhibit B and summarized in Table 1 as follows:

Table 1
Total Estimated Capital Costs at Completion
(Millions of Escalated Dollars)

	Total System (1992 Completion)	Phase I System (1988 Completion)
Pipeline	$ 14,648	$ 7,569
Conditioning Facilities	2,520	1,104
Liquefaction Facilities	8,297	2,883
Total System	$ 25,465	$ 11,556

The escalated capital costs represent the respective amounts that would need to be financed under each case. However, under the Total System case partial operations would commence four years prior to System completion and revenues and tax savings in the base analyses will repay approximately $5.0 billion of debt and provide approximately $1.7 billion of dividends to equity prior to full completion of the System. Viewed another way, should the Total System be completed and operated as scheduled under the assumptions used, financing commitments could be reduced by the amount of the cash flow generated during partial operations.

Base Analyses Revenues

Based on the estimated capital costs developed for each case the financial analyses apply the assumptions used in the base analyses over the life of the System to determine the annual tariff requirements of the System. Annual required tariff income of the System is that minimum annual stream of revenue which, over the life of the System, is sufficient to cover all projected operating costs including fuel and taxes, repay principal and interest on debt and provide the equity sponsors the required return on and return of investment.

Base Analyses Tariffs Delivered In South Alaska

The annual tariff requirement for each System component divided by the total gas product throughput on the basis of Btu content represents the tariff for each component on a unit of gas basis. Unit tariff costs are expressed in terms of dollars per MMBtu's. The sum of the prospective tariffs for each component represents the total unit cost or System tariff. The System tariff, therefore, represents the costs of transporting, conditioning and liquefying one MMBtu of LNG delivered in South Alaska and the cost of transporting, conditioning and fractionating one MMBtu of NGL products delivered in South Alaska. Tariffs are expressed in nominal dollars. Tariffs are also assumed to include the costs that the System will pay the owners of the gas for System fuel. System fuel costs are assumed to be the amount of the economic value of the gas delivered in each case analyzed. Tariff costs do not include wellhead prices for gas (other than for System fuel) or costs of shipping gas products to market.

The tariffs developed in the base analyses for each component in the lower tariff case and the higher tariff case are set forth in Exhibit C and are summarized in Table 2 in nominal dollars for the first year of operations, the last year and the average over the operating life of the System.

Table 2

Prospective System Tariffs Delivered In South Alaska

(Nominal Dollars Per MMBtu)

	Total System	
	Lower Range	Higher Range
1988	$ 4.67	$ 6.16
2011	22.14	29.20
Average	11.32	14.93

	Phase I System	
	Lower Range	Higher Range
1988	$ 5.94	$ 7.91
2007	21.48	28.61
Average	12.18	16.21

Prospective Costs of System LNG Delivered In Japan

Prospective cost of System LNG (other than wellhead prices) delivered in Japan is the total of prospective System tariffs delivered in South Alaska plus estimated LNG tanker costs for shipments to Japan as set forth in Table 3 below:

Table 3

Prospective Costs of System LNG Delivered In Japan

(Nominal Dollars Per MMBtu)

Total System

	LNG Tariffs South Alaska (Lower Range)	LNG Tariffs South Alaska (Higher Range)	Projected Shipping Costs	LNG Delivered Costs Japan (Lower Range)	LNG Delivered Costs Japan (Higher Range)
1988	4.67	6.16	1.00	5.67	7.16
2011	22.14	29.20	4.07	26.21	33.27
Average	11.32	14.93	2.20	13.52	17.13

Phase I System

	LNG Tariffs South Alaska (Lower Range)	LNG Tariffs South Alaska (Higher Range)	Projected Shipping Costs	LNG Delivered Costs Japan (Lower Range)	LNG Delivered Costs Japan (Higher Range)
1988	5.94	7.91	1.00	6.94	8.91
2007	21.48	28.61	3.19	24.67	31.80
Average	12.18	16.21	1.90	14.08	18.11

System LNG Delivered Costs in Japan Compared with Projected Japanese LNG Prices

The projected costs of System LNG delivered in Japan have been compared in the Table 4 below to MRI's projected market prices in Japan of imported LNG.

The difference between prospective System LNG delivered costs and forecasted market prices represents the potential economic value (positive or negative) of System LNG in Japan after all System tariff and shipping costs have been met. A significantly positive differential would illustrate the System's potential ability to cover all operating and shipping costs and provide a significant economic value for the LNG. Little or no differential indicates that the System may be only marginally economic in recovering System costs with little economic value for the LNG. A negative differential means that in addition to no economic value for the LNG, System costs would not be recovered unless prospective equity return was reduced.

Table 4

Prospective System LNG Costs Delivered In Japan
Compared with Projected Japanese LNG Prices

(Nominal Dollars Per MMBtu)

Total System

	System LNG Costs Japan (Lower Tariff)	System LNG Costs Japan (Higher Tariff)	Japanese LNG Price Forecast	Economic Value of LNG (Lower Tariff)	Economic Value of LNG (Higher Tariff)
1988	5.67	7.16	7.89	2.22	0.73
2011	26.21	33.27	37.40	11.19	4.13
Average	13.52	17.13	19.13	5.61	2.00

Phase I System

	System LNG Costs Japan (Lower Tariff)	System LNG Costs Japan (Higher Tariff)	Japanese LNG Price Forecast	Economic Value of LNG (Lower Tariff)	Economic Value of LNG (Higher Tariff)
1988	6.94	8.91	7.89	0.95	(1.02)
2007	24.67	31.80	28.53	3.86	(3.27)
Average	14.08	18.11	16.17	2.09	(1.94)

Prospective System NGL Costs Per Barrel Delivered In South Alaska

Prospective System NGL tariffs delivered in South Alaska developed by the base analyses have not been analyzed in connection with Japanese markets but provide a basis of comparison for North Slope producers in evaluating cost estimates of alternative options of conditioning and transporting NGL products. NGL tariffs on a Btu basis are the same as LNG tariffs on a Btu basis as set forth in Table 2. On a per barrel equivalent basis, the System's major NGL products, propane and butane, could be delivered in South Alaska at the prices in nominal 1988 dollars set forth in Table 5:

Table 5

Prospective System NGL Costs Per Barrel Delivered In South Alaska

(1988 Nominal Dollars Per Barrel)

	Total System	
	Lower Tariff	Higher Tariff
Propane	$17.79	$23.47
Butane	20.50	27.04

	Phase I System	
	Lower Tariff	Higher Tariff
Propane	$22.63	$30.14
Butane	26.08	34.72

Economic Sensitivity Analyses

At the present preliminary stage of study of the TAGS proposal there remain significant uncertainties with respect to cost estimates and economic and financial assumptions in connection with a project of the scale of TAGS. It is possible that the estimated range of tariff costs projected by the base analyses could vary in substantial degree with changes in capital costs and changes in base assumptions.

Possible assumption variations which would increase the tariff include construction cost overruns, an increase in equity investment as a percentage of the capital structure, a decline in throughput in the System, ten year rather than 5 year tax depreciation for the pipeline facilities, and increases in general inflation rates, interest costs and operating and maintenance expenses.

Possible assumption changes which would decrease prospective tariffs include level debt service treatment of debt stretching out debt over a longer average life and increasing leverage, State of Alaska participation through tax exempt revenue bond financing of facilities such as the liquefaction component, a higher tariff price path and the expensing of construction period interest rather than capitalization.

Because of these potential changes the analyses review specific variations in construction costs and base assumptions in order to determine System sensitivity. The effects of variations in key assumptions on System tariffs are examined below. The sensitivity cases are compared with tariffs resulting from the base analyses of the Total System's lower range tariffs.

As the sensitivity results indicate, potential changes in construction costs and level debt service are the two most significant sensitivity cases affecting prospective System tariffs (apart from changes in required equity return assumed in the lower and higher tariff cases).

Construction Cost Overruns

The effect of a 30% construction cost overrun (which would represent a total overrun of approximately 56% because of contingencies of 20% already built into the Brown & Root estimated construction costs) on System tariffs is shown in the table below:

	Total System Tariffs Per MMBtu	
Increase In Construction Costs		
30%	$	5.72
Base Analyses (Lower Range)		4.67

Capital Structure

A decrease in debt leverage and increase in equity investment resulting in a 70-30% debt-equity capital structure would have the following effect on System tariffs:

	Total System Tariffs Per MMBtu	
70-30% Debt-Equity Capital Structure	$	5.07
75-25% Debt-Equity Capital Structure-Base Analyses (Lower Range)		4.67

Throughput

The effect of a 10% decrease in gas throughput on System tariffs is shown in the table below:

	Total System Tariffs Per MMBtu	
Decrease In Throughput MMBtu		
(10%)	$	5.09
Base Analyses (Lower Range)		4.67

Tax Depreciation of Pipeline

The effect of ten year tax depreciation for pipeline facilities rather than five years used in the base analyses on System tariffs is shown below:

	Total System Tariffs Per MMBtu
Ten Year Tax Depreciation	$ 4.89
Five Year Tax Depreciation Base Analyses (Lower Range)	4.67

Inflation Rate for Construction, Operating and Maintenance Costs

The effect of a 1% change in the assumed rate of inflation of construction costs and operating and maintenance expenses on System tariffs is shown in the table below:

	Total System Tariffs Per MMBtu
8%	$ 4.88
7 Base Analyses (Lower Range)	4.67
6	4.48

Interest Rate

The effect of a 1% change in the assumed rate of interest on System tariffs is shown in the table below:

	Total System Tariffs Per MMBtu
15%	$ 4.78
14 Base Analyses (Lower Range)	4.67
13	4.55

Operating and Maintenance Expenses

The effect of an increase of 10% in projected operating and maintenance expenses on System tariffs is shown in the table below:

	Total System Tariffs Per MMBtu
Increase In Operating and Maintenance Expenses	
10%	$ 4.68
Base Analyses (Lower Range)	4.67

Level Debt Sinking Fund Payments

The base analyses assume that System revenues would retire invested capital on the basis of a 3 to 1 debt to equity ratio. Because of large cash flows anticipated in the early years from accelerated tax depreciation, debt repayment is relatively large in the first five years. If, however, System debt were repaid on a level sinking fund basis over twenty years debt payments would be stretched out and debt leverage increased with an improvement in System tariffs as follows:

	Total System Tariffs Per MMBtu
Level Debt Sinking Fund Payments (5% Annually)	$ 3.81
3 to 1 Debt to Equity Ratio-Base Assumption (Lower Range)	$ 4.67

Tax Exempt Financing-Liquefaction Facilities

It may be possible for the State of Alaska to participate in System financing by providing debt funds through the issuance of tax exempt revenue bonds related to System facilities. The positive effect of financing all of the liquefaction facilities by tax exempt revenue bonds is reflected in the reduction in the liquefaction tariffs and Total System tariffs as shown in the table below:

	Liquefaction Facilities' Total Tariffs Per MMBtu
Tax Exempt Financing	$ 0.84
Private Investor Project Financing - Base Analyses (Lower Range)	1.34

	Total System Tariffs Per MMBtu
Tax Exempt Financing	$ 4.24
Private Investor Project Financing - Base Analyses (Lower Range)	4.67

Tariff Price Path

The effects of a 1% increase or decrease in the price path of System's tariffs is shown below:

	Total Tariffs Per MMBtu
6%	$ 4.89
7 Base Analyses (Lower Range)	4.67
8	4.46

Interest During Construction Expensed

The base analyses assumes that the System might not be entitled to an exemption to the provision in the 1982 Tax Act which would require the capitalization of interest incurred during construction. However, because required interest capitalization is not certain and because the System's anticipated construction interest expenses will be large during the prolonged construction period, a sensitivity case assuming full deductability of construction interest during construction has been run. The effect of expensing rather than capitalized construction interest reduces System tariffs as shown in the table below:

	Total Tariffs Per MMBtu
Construction Interest Expensed	$ 4.62
Construction Interest Capitalized - Base Analyses (Lower Range)	4.67

Exhibit A1

Trans Alaska Gas System

Brown & Root

Preliminary Construction

and Organization Cost Forecast

(Millions of 1982 Dollars)

	Phase I System	Phase II	Total System
Pipeline			
Pipeline	$4,548	$6,216	$8,183
Organization	60	60	60
Total Pipeline	$4,608	$6,276	$8,243
Conditioning Facilities			
Gas Treating	76	117	155
NGL Extraction	302	463	609
NGL Fractionation	147	225	310
NGL Storage & Loading	167	167	339
Subtotal	692	972	1,413
Organization	10	10	10
Total Conditioning	702	982	1,423
Liquefaction Facilities			
LNG (Liquefaction, Storage and Loading)	1,640	2,772	4,405
Dock Facilities	193	193	193
Organization	30	30	30
Total Liquefaction	1,863	2,995	4,628
Total	$7,173	$10,253	$14,294

Trans Alaska Gas System

Brown & Root

Preliminary

Construction and Organization Spending Forecast

(Millions of 1982 dollars)

Item		1	2	3	4	5	Cumulative Phase 1 System	6	7	8	9	Cumulative Total System
Pipeline	- Construction	$ 376	$ 434	$ 1,050	$ 1,355	$ 1,333	$ 4,548	$ 863	$ 805	$ 996	$ 971	$ 8,183
	Organization	20	20	20	-	-	60	-	-	-	-	60
Conditioning	- Construction	-	-	-	346	346	692	140	140	221	220	1,413
	Organization	4	3	3	-	-	10	-	-	-	-	10
Liquefaction	- Construction	-	-	-	917	916	1,833	566	566	817	816	4,598
	Organization	10	10	10	-	-	30	-	-	-	-	30
Total		$ 410	$ 467	$ 1,083	$ 2,618	$ 2,595	$ 7,173	$ 1,569	$ 1,511	$ 2,034	$ 2,007	$ 14,294
Cumulative Phase I System		$ 410	$ 877	$ 1,960	$ 4,578	$ 7,173	$ 7,173	-	-	-	-	$ 7,173
Cumulative Total System		$ 410	$ 877	$ 1,960	$ 4,578	$ 7,173	$ 7,173	$ 8,742	$ 10,253	$ 12,287	$ 14,294	$ 14,294

Trans Alaska Gas System

Brown & Root

Preliminary Operating

and Maintenance Expense Forecast(1)

(Millions of 1982 Dollars)

	Phase I System	Phase II	Total System
Pipeline	$ 20	$ 35	$ 49
Conditioning Facilities	19	27	39
Liquefaction Facilities	39	66	105
Total	$ 78	$128	$193

(1) Excludes cost of fuel.

Trans Alaska Gas System

Preliminary Projected Capital Costs

Total System - Base Analyses

(Millions of Dollars - 1992 Completion)

	Pipeline	Conditioning	Liquefaction	Total
Construction Costs (1)	$ 8,183	$ 1,413	$ 4,598	14,194
Organization Costs	60	10	30	100
Total	$ 8,243	$ 1,423	$ 4,628	14,294
Property Taxes	980	152	94	1,226
Escalation	3,267	666	2,644	6,577
Subtotal	12,490	2,241	7,366	22,097
Interest and Financing Costs				
During Construction	2,148	274	906	3,328
Working Capital	10	5	25	40
Total Capital Costs	$ 14,648	$ 2,520	$ 8,297	$ 25,465

(1) Estimated by Brown & Root and includes 20% contingency amount.

Trans Alaska Gas System

Preliminary Projected Capital Costs

Phase I System - Base Analyses

(Millions of Dollars - 1988 Completion)

	Pipeline	Conditioning	Liquefaction	Total
Construction Costs(1)	$ 4,548	$ 692	$ 1,833	$ 7,073
Organization Costs	60	10	30	100
Total	$ 4,608	$ 702	$ 1,863	$ 7,173
Property Taxes	216	21	11	248
Escalation	1,364	258	672	2,294
Subtotal	6,188	981	2,546	9,715
Interest and Financing Costs During Construction	1,371	118	312	1,801
Working Capital	10	5	25	40
Total Capital Costs 1988	$ 7,569	$ 1,104	$ 2,883	$ 11,556

(1) Estimated by Brown & Root and includes 20% contingency amount.

Exhibit C1

Trans Alaska Gas System

Preliminary Projected Tariffs Delivered In South Alaska

Total System - Base Analyses

(Dollars Per MMBtu)

	Pipeline	Conditioning	Liquefaction	Total System
Lower Tariff Range				
Nominal 1988 Dollars	2.86	0.48	1.33	4.67
Nominal 2011 Dollars	13.57	2.26	6.31	22.14
Nominal Average Dollars	6.93	1.16	3.23	11.32
Higher Tariff Range				
Nominal 1988 Dollars	3.92	0.59	1.65	6.16
Nominal 2011 Dollars	18.63	2.80	7.77	29.20
Nominal Average Dollars	9.53	1.43	3.97	14.93

Exhibit C2

Trans Alaska Gas System

Preliminary Projected Tariffs Delivered In South Alaska

Phase I System - Base Analyses

(Dollars Per MMBtu)

	Pipeline	Conditioning	Liquefaction	Phase I System
Lower Tarriff Range				
Nominal 1988 Dollars	$3.95	$ 0.58	$ 1.41	$ 5.94
Nominal 2007 Dollars	14.30	2.11	5.07	21.48
Nominal Average Dollars	8.09	1.20	2.89	12.18
Higher Tariff Range				
Nominal 1988 Dollars	$5.42	$ 0.72	$ 1.77	$ 7.91
Nominal 2007 Dollars	19.59	2.62	6.40	28.61
Nominal Average Dollars	11.11	1.48	3.62	16.21

MARKETING

I. Conclusions and Summary

A. Conclusions

1. The United States is late in offering North Slope LNG to the Pacific Rim's most lucrative market, Japan. Committee advisors' projections vary on the amount of LNG Japan could absorb in 1990. Projections below do not include a now-pending deal for shipment of 2.9 MMT per year from Canada to Japan:

Estimated Japanese 1990 Supply, Demand, Shortfall
(Million Metric Tons)

	Supply	Demand	Shortfall
Mitsubishi/C. Itoh	35	37	2
Mitsui	34.1	38.1	4
Marubeni	37	42-46	5-9
Sumitomo	37	39-44	2-7
MITI	34	43	9

2. Alaska's competition in the Pacific Rim market includes the Soviet Union, Indonesia, Australia, and Canada as well as a host of other prospective sellers. If the preliminary economic findings in this report are correct, Alaska is competitive against these suppliers. Action must be taken now to enter the market.

3. U.S. demand for LNG from Alaska is uncertain, as indicated by PAC Alaska LNG Associates' recent decision to defer bringing Cook Inlet Alaskan gas to California.

4. Petrochemical markets, now glutted world-wide, may offer a long term opportunity for Alaska supplies and in-state processing.

5. Estimated shipping costs to serve Asian markets vary widely depending whether now mothballed U.S. ships are used, new Japanese or Korean ships are constructed, or U.S. Jones Act ships are built. Delivered in Japan the range of tariffs runs from .47 per MMBTU to $1.11.

B. Summary

For this report, the Governor's Economic Committee is relying on the advice of several American and Japanese companies in the business of producing, trading, and shipping energy. The committee has benefitted from conversations with government officials on both sides of the Pacific.

Natural markets for North Slope gas delivered to tidewater exist in the industrialized Pacific Rim nations. These nations include Japan, Korea and the West Coast of the United States. In the United States, gas reserves in the Lower-48 states and supplies deliverable from Canada and Mexico are expected to meet demand through the end of the century. Pacific Alaska LNG Associates, who have commitments to bring LNG into California from Cook Inlet Alaska and Indonesia, have postponed operations until at least 1990.

The committee has concluded after investigation that North Slope producers should focus on Japan as the major market, though not the only market, for their gas. Phase I of TAGS would make available approximately 4.8 million tons of LNG in 1988. Phase III, the total system, would increase TAGS throughput to 14.5 million tons. Estimates of Japanese need beyond those sources already committeed range from 2 to 9 million tons in 1990 and 9 to 17 million tons in 1995. Thus, there is a window open yet for Alaskan supplies by the end of the decade. That window will close tightly if the United States does not act soon. Competition from Canada, Australia, Indonesia, and the Soviet Union — each of whom have at least two years' lead time in approaching the market -- is such that projected demand in Japan may already be met until after 1990.

C. United States Energy and Trade Policy

Except for Canada, where export contracts have not been ratified, each of those competing nations carry an additional advantage at present: the full support of their governments. While the United States has needed to find large value exports to balance its trade with Japan in recent years, energy policy in the United States has built a wall around its borders. Potential Asian trading partners have been forced to look elsewhere. While Japan and Korea have answered OPEC generated oil shocks with attempts to diversify supply, requests that the United States sell oil and gas have been rebuked under America's policy to establish "energy independence" at home. Such a policy might have made sense at a time of rising prices and uncertainty about supply. But today, in a time of declining oil prices and shut-in gas wells throughout the United States, exploration -- the lifeblood of an energy independence policy -- is depressed as well. A free American market in energy could spur exploration again by involving new investors and markets. Regardless of whether the United States can use new Alaska oil and gas finds immediately, it benefits both the United States and its trading partners outside OPEC to keep on looking. Establishment of a North Slope gas transportation system before 1990 will keep that process on schedule.

Two facts provided by oil companies operating in Alaska help show how bringing gas to a market will further America's goal of energy independence. At Prudhoe Bay today, a number of high gas-oil ratio wells are not produced because of the economic costs of reinjecting the gas. Once gas shipments begin, testimony indicates, 100,000 additional barrels per day of Prudhoe oil can be produced.

Costs of gas reinjection give North Slope gas a negative value to its owners today, assuming alternative methods are available for secondary oil recovery. Only a transportation system can give the gas a value. Recent bidders on oil exploration tracts in the area have told the Committee that the possibility of finding gas on Arctic tracts is high enough that there is a substantial chance a discovery well will not be producible without a gas transportation system. Bid prices have been discounted accordingly and some areas with known gas reserves have produced little leasing interest at all.

If America's energy policy calls for its government to advocate the export of Alaska gas, America's foreign policy as a matter of trade and national security does so as well.

In trade policy, a massive balance of trade deficit with Japan gives the United States both need and leverage to work with the Japanese for a remedy. This project can be part of that remedy, and useful for both nations.

As a matter of national security, the United States has recently expressed strong concern to the Soviet Union's neighbors on both sides of the Eurasian continent that free world nations do not unduly rely on the Soviet Union for energy. Save for American attempts to export more coal, this country has been slow in offering either our NATO or SEATO allies an alternative. Alaska North Slope gas represents an alternative to Soviet Union gas from the Sakhalin Island, which is scheduled for marketing in 1989, one year after the Alaska project could be on line. Under the TAGS schedule, Alaska can beat Sakhalin to market.

As Japan and other Asian nations have sought to diversify sources of energy, commitments from abroad have brought about more than just commercial relationships. If the United States continues to refuse to participate in the Pacific Rim energy supply picture, it may see its Pacific partners realign in other areas as well. Political interdependence, helpful for national security, often follows commercial interdependence.

D. <u>Japan's Energy and Trade Policy</u>

A May, 1982 report on the LNG market in Japan by Marubeni Corporation provided the following description of Japanese government policy toward LNG.

It is a fundamental policy of the Japanese Government to pursue a stable supply of energy to promote the public welfare and national security. Environmental aspects must also be considered. To achieve the policy, the following measures are slated:

1. Securing a stable supply of oil.
2. Promotion of energy conservation

3. Promotion of development and introduction of alternative energies
4. Promotion of siting for electric power plants
5. International cooperation

It is resolute for the Japanese Government, as mentioned above, to pursue the promotion of development and introduction of alternative energies to reduce dependence on oil. In October, 1981 the government established the "New Energy Development Organization" and charged it with responsibilities (1) to develop technology for new energies, such as coal liquefaction and solar energy, (2) to develop geothermal resources, and (3) to develop overseas coal resources. The May 1980 law which came before this organization furthermore covers nuclear energy, hydro power, and LNG.

LNG is regarded as a fuel having long-term security of supply, when compared with oil, and is expected to play a major role among alternative energies, together with nuclear energy and coal, through use in electric power and gas industries. In the future, especially, LNG is assumed to be increasingly consumed in the town gas industry through (1) resale of gas by LNG importers to smaller gas enterprises and large industrial consumers and (2) spread of gas air-cooling systems nationwide.

To encourage faster introduction of LNG into Japan's energy framework, the Japanese Government has adopted the following policies:

Immediate Policy

1. Aid for exploration, development and production
    a. Aid by Japan National Oil Corporation (JNOC). Under legislative provisions established in 1972 governing the activities of JNOC, JNOC is permitted to provide financial aid to gas exploration and development ventures in the form of equity capital and loans. Guarantees of obligations can be obtained from JNOC for production of

LNG. JNOC was authorized in Fiscal Year 1982 to provide 140 billion yen (about US $600 million) of financial aid and 1 billion yen (about US $4 million) of guarantees of obligation.

b. Credit by The Export-Import Bank of Japan (EXIM Bank). By co-financing with commercial banks the EXIM Bank extends credit to exporters to provide them with funds necessary to cover their deferred payment credits in connection with liquefaction plant construction. The EXIM Bank had in FY 1982 a budgetal frame of 312 billion yen (about US $1.3 billion) to promote imports to Japan.

c. Loans by the Development Bank of Japan (DBJ). The Government's Shipbuilding Program includes in FY 1981 loans of 117 billion yen (about US $500 million) by the DBJ coupled with government interest subsidies of 6.63 billion yen (about US $28 million). The 1981 program allowed construction of three LNG tankers, 600,000 gross tons of energy-resources transportation vessels, and other 300,000 ton vessels.

2. Exemption of import duty for LNG. To encourage the import of LNG the Government exempts import duty, a basic tariff of 20%.

3. Aid for LNG facilities. To prevent pollution and to improve individual life, the Development Bank of Japan offers loans to electric power companies for construction of LNG-fired power plants and to gas companies for construction of LNG receiving terminals.

The DBJ also makes available to LNG consumers credits for construction of LNG related facilities, such as pipelines for the exclusive use of regasified LNG, and installation of industrial furnaces and boilers being fueled by regasified LNG.

4. Special tax arrangements. LNG consumers are allowed to choose either a 7% tax deduction or a 30% special depreciation rate for their accounting in connection with LNG related facilities and equipment.

5. Special contract rate for large industrial LNG consumers. The rate is now around 7-8 yen per 1,000 kcal (about US $7.35/MMBTU), which is almost equivalent to rates for kerosene and light fuel oil.

6. Subsidy for studies. Subsidies are extended to local governments to study the possibility of introducing of LNG into local industries and to study siting and environmental issues of a receiving terminal and secondary transportation. In FY 1981 the amount of 85 million yen (about US $350,000) was provided.

Policy Toward The Future

1. To progressively develop and maintain good diplomatic relations with exporting countries, which will contribute to the security of long-term supply of LNG.

2. To enrich conditions of loans associated with construction of liquefaction plants by EXIM Bank, JNOC and Overseas Economic Cooperation Fund (OECF) in favor of LNG consumers and also to enrich the condition of guarantees of obligation extended by JNOC.

3. To arrange low-interest-financing and favored tax mechanisms for construction of LNG receiving terminals.

4. In order to facilitate siting of LNG receiving terminals and LNG-fired power plants, the government:

   a. promotes policies to form agreement of surrounding and local people on the safety of LNG and the necessity of its introduction.

b. establishes fine-grained siting policies which suit to each specific location.

5. In order to meet regulations for reclamation and for navigation the government makes certain:

   a. thoroughly advance surveys on safety and environment are performed.

   b. a structure which coordinates concerned institutions and parties is established.

6. To strengthen the system of governmental aid in order that Japanese building of LNG tanker construction and possession and operation of LNG tankers by Japanese shipping companies is internationally competitive with those of advanced countries, and to promote a structure for cooperation of concerned business circles.

7. To examine a domestic system of LNG receiving corresponding with a "take or pay" clause which is common in LNG supply contracts.

8. In order to expedite more use of LNG in gas enterprises and other industries, to strengthen measures of governmental aid for laying pipelines to connect with existing LNG pipelines and for changing in heat value, and examine structures to collect small demands together to supply LNG at low cost.

II. <u>North Slope Supplies Made Available by TAGS</u>

For the purpose of facilitating the entry of North Slope gas on the world market as well as making financing easier for the project as a whole, the Trans-Alaska Gas System has been envisioned in three phases, with varying throughputs available.

	Phase I	Phase II	Phase III
Online	1988	1990	1992
Raw gas/ mmcfpd	950	1750	2830
LNG/Million Metric Tons per year	4.8	8.9	14.5

Additionally, the pipeline will make available substantial quantities of gas liquids besides the methane and ethane contained in the figure above. All quantities are listed in 42 gallon barrels.

	Natural Gas Liquids Available (Barrels Per Day)		
Propane	19,000	35,000	56,600
Butanes	10,450	19,250	31,130
Pentanes Plus	8,550	15,750	25,470

III. Prospects of Demand and Supply of LNG in Asia

A. Present Situation In Japan

The Japanese economy's growth rate has dropped to around 3 percent in recent years with considerable sluggishness in steel, petrochemical and other energy intensive industries. Due to decreased growth and conservation measures, demand for energy has been almost level in Japan for the last three years.

Amid overall stagnancy in energy demand, LNG consumption has shown a steady increase because the power industry and city gas suppliers, two major users of LNG, have moved to replace oil with LNG.

Japan's annual LNG consumption is currently 17 MMT (Million Metric Tons,) of which 75 percent is consumed by the power industry, 21 percent by city gas suppliers and 4 percent by steelmakers.

Under these circumstances, Mitsubishi Research Institute and C. Itoh, collaborators for this section of the report, regard the following two issues as important factors in making a forecast for LNG demand in Japan:

1. Prospects of overall demand for electricity and city gas, which is associated with future economic growth rates.

2. The degree to which these two industries will depend on LNG as opposed to other forms of energy. For instance, electric power can be generated from coal, hydro, nuclear and oil as well as domestic natural gas and imported LNG.

B. Prospects For Japan

1. Government's Forecast and Its Problems

The Japanese Ministry for International Trade and Industry (MITI) announced in May, 1982 the Long-term Forecast on Demand and Supply of Energy by 2000. The forecast said that:

a. The Japanese economy will grow at an average annual rate of 5 percent until 1990, and at 4 percent for the next 10 years.

b. Overall demand for energy in oil terms will rise at an average annual rate of 3.2 percent from 429 million kiloliters (MKL) (68.2 million barrels) in 1980 to 590 MKL (93.8 million barrels) in 1990 and will increase 2.7 percent per annum during the next 10 years to 770 MKL (122.4 million barrels) in 2000.

c. Meanwhile, demand for electricity (which is closely associated with demand for LNG), will show an average growth rate of around 4 percent during 1980-2000 and demand for city gas, which is covered only implicitly in this forecast, will presumably grow at some 4.5 percent during the period.

d. As a result, total demand for LNG will show a steep rise from 17 MMT in 1980 to 43 MMT in 1990, and further to 50 MMT in 2000.

The chart on the next page shows the forecast for Japan's LNG supply and demand based on the MITI's long-term energy supply and demand forecast. The supply quantities shown in this figure are all contracted or quasi-contracted quantities as of April 1982. Canadian LNG is excluded from the chart since the supply of LNG from Canada is still subject to the approval of the Canadian National Energy Board (NEB) at the present moment.

According to MITI, the 43 million MT of demand in 1990 will consist of 31.5 million MT of demand from electric power companies and 11.35 million MT of demand from gas companies. (The balance of 150,000 MT represents demand from miscellaneous users.)

The chart indicates that there will be 8.8 million MT/year of demand for LNG in excess of contracted or quasi-contracted supply quantities in 1990, 17.44 million MT/year in 1995 and 31.5 million MT/year in 2000. Should the export of Canadian LNG be approved by the NEB, these figures will require a 2.9 million MT/year downward adjustment.

However, due to trends in the Japanese economy since the April, 1982 projections, including the unexpected low growth of electricity and gas demand, additional downward revisions in the MITI's forecast appear necessary. Those revisions, if they are forthcoming, have not yet been announced.

It was recently reported that economic growth during 1983-1987 would be revised downward to the level of 3% per annum, although 5.0% was the level assumed in MITI's latest forecast. The electric power industry experienced surprisingly low growth in demand for electricity during April-August 1982, with an annual growth rate of only 0.5%, in comparision with a 4.4% growth rate expected by the electric power industry at the beginning of 1982.

FIGURE-2 FORECAST OF JAPANESE LNG SUPPLY AND DEMAND

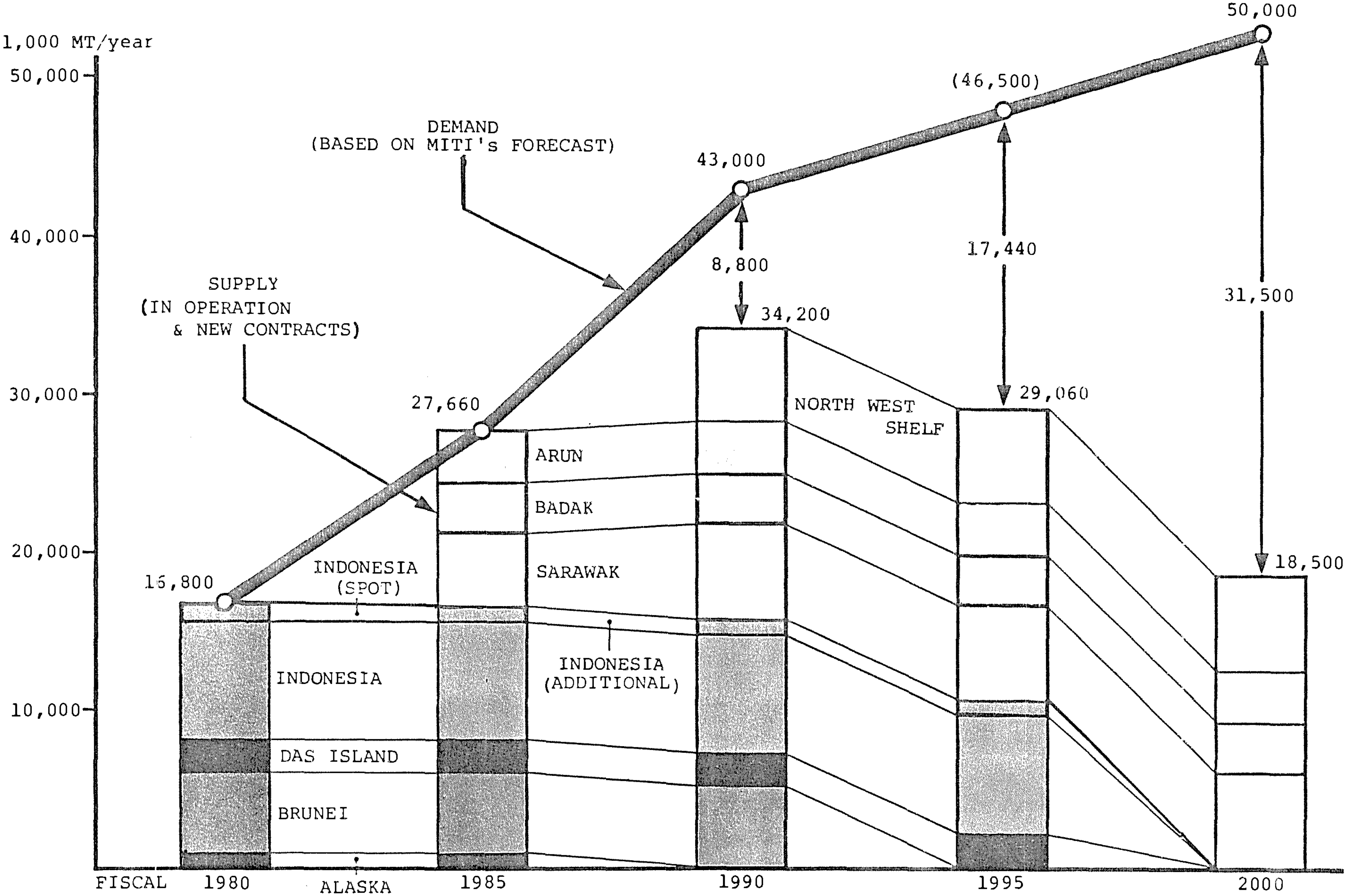


Chart Source: Mitsui & Co., LTD

This low growth of electricity demand has resulted partly from relatively cool weather during the summer of 1982, but there is no doubt that it also reflects the further strengthening of trends in Japanese industry toward less energy-consuming products, and consequently, this tendency toward reduced electricity demand growth can be expected to continue.

It must be noted, therefore, that the government's forecast is, in its nature, something like a target toward which efforts should be made. Thus, Mitsubishi Research Institute provided the Committee with a separate forecast.

C. <u>Forecast by Mitsubishi Research Institute</u>

1. Mitsubishi Research Institute Forecast

   a. The Japanese economy will grow at an average annual rate of 3 percent in 1980-90 and 2 percent in 1990-2000.

   b. Overall demand for energy will rise at an average annual rate of 1.5 percent in 1980-90 and 2 percent in 1990-2000.

   c. Growth in electricity demand will be 2.6 percent annually in 1980-90 and 2 percent in 1990-2000, considerably lower than government's forecast, because electricity demand will experience a firm increase in households while it will level off in industries. Demand for city gas is expected to record a little higher growth than that for the power industry with an average annual rate of 3.6 percent for 1980-90 and 2.5 percent for 1990-2000. Both rates are fairly lower than Government's forecast.

   d. City gas suppliers have launched a project aimed at raising pipe transportation efficiency by switching to higher-calorie natural gas to reduce dependence on oil and rely more on natural gas considerably by 1990. This project is going well and the project will be completed around 1990. After 1990, however, dependence on LNG will not increase sharply. Typical LNG projects deliver constant supplies year-round, rather than meeting seasonal ups-and-downs in city gas production. Thus LNG dependence will match base load demand growth. As well, city gas, which is made from LNG, is supplied only in and around big cities.

e. The power industry plans to build many LNG-burning plants and is also making provision for necessary LNG supply. After these plants are constructed, overall generating capacity of LNG-burning plants will come to 37.6 BW (Billion Watts) in 1990, up from 19.7 BW in 1980. LNG-burning plants' share will rise to 24 percent in 1990 from 15 percent in 1980 in generating volume terms. After 1990, however, Mitsubishi Research Institute does not expect the share to show a sharp increase. There are following two reasons:

   (1) The power industry presently depends for its base load, which shows no seasonal and daily fluctuations, on nuclear, hydroelectric and LNG-burning plants. From the viewpoint of economic benefits, however, the power industry gives the priority to nuclear and hydroelectric plants. A substansial increase in LNG cannot be expected, because it causes operational difficulties to meet the medium load, which shows seasonal and daily fluctuations.

   (2) As LNG is priced the same as oil in calorie-equivalent terms, and LNG-burning plants also require huge investments for construction of receiving terminals and trunk lines, etc., LNG-burning plants may not offer much economic benefit compared to oil-burning plants.

f. Taking these analyses into account, Mitsubishi Research Institute's forecast LNG demand in Japan is below:

LNG Forecast Demand for Japan
by Mitsubishi Research Institute
(Millions of Metric Tons)

	1980	1990	2000
Power Plant	13.0	28.2	35.0
City Gas	3.4	8.2	10.4
Others	0.6	0.6	0.6
Total	17.0	37.0	46.0

D. LNG Development Projects

1. Supply to Japan

a. Volume of LNG to be supplied from existing projects and other projects to start operations by 1990

(1) Existing Projects

There are four projects in Alaska, Brunei, Abu Dhabi and Indonesia which are supplying LNG to Japan.

Under the contracts, they ship a total of 15.7 MMT LNG to Japan a year. Among them, Alaska and Indonesia projects deserve special explanation.

Alaska The supply contract is to expire in 1984, but five-year extension of the deal has been agreed between the both sides and they applied to the Department of Energy (DOE) for export permission. DOE is expected to give the permission soon.

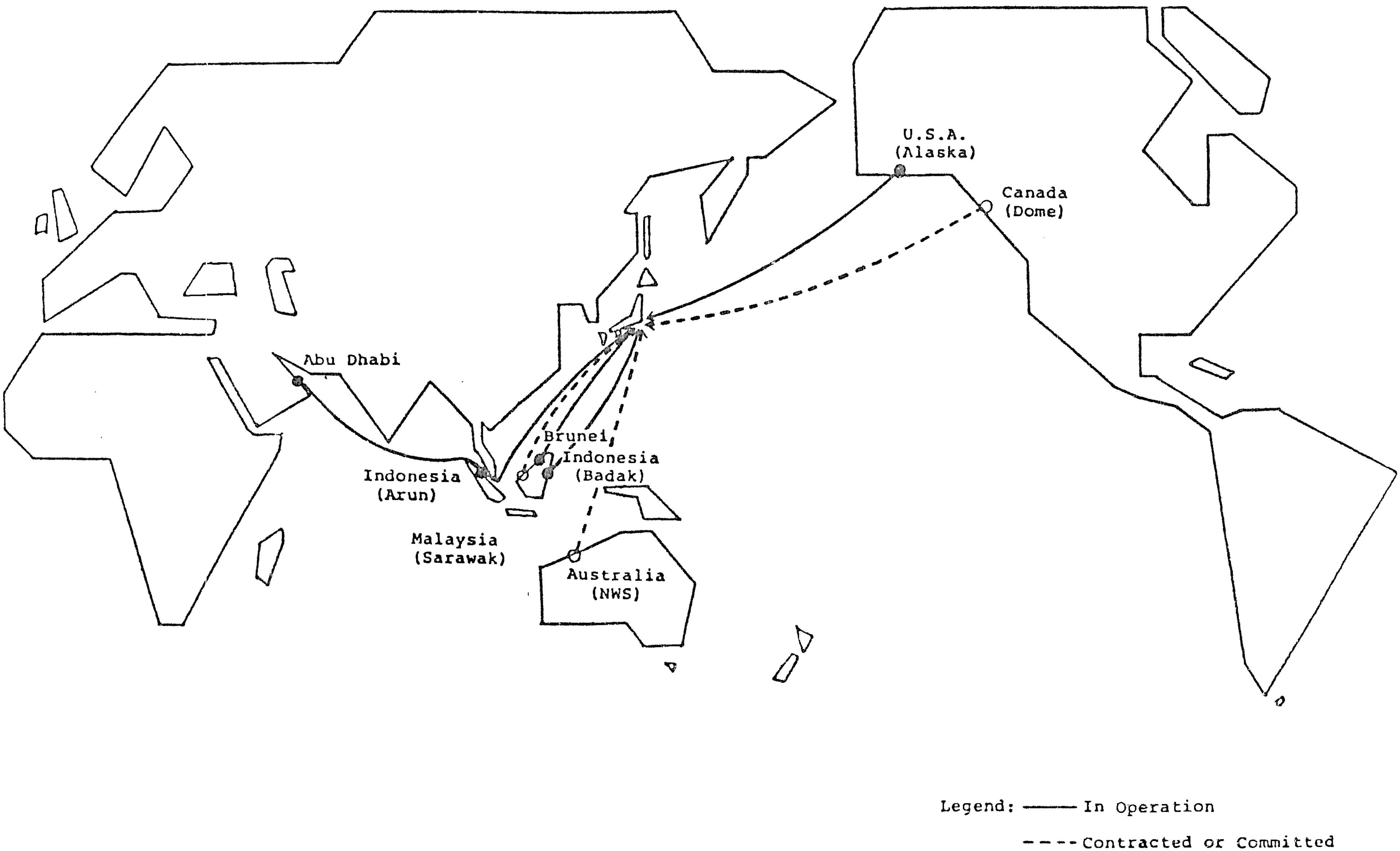
Indonesia is providing Japan with LNG which exceeds contracted volume of 7.5 MMT a year. In 1983, it will supply an additional 1.5 MMT.

(2) Projects to Start Operations by 1990

Malaysia, Indonesia (Arun and Badak), Australia and Canada are scheduled to provide Japan with a total of 21.4 MMT a year.

1. LNG Projects for Japan

(In Operation, Contracted and Committed)



Malaysia is scheduled to enter into full operation four years after starting operations in January, 1983. At present, the project is in the final construction phase and final negotiations are going on between suppliers and purchasers. The project is expected to provide Japan with 6.0 MMT a year.

Indonesia The basic contract, signed in April, 1981, between PERTAMINA and Japanese customers, provided that Japan will import 3.3 MMT a year from Arun and 3.2 MMT from Badak. The two plants and LNG-carriers are under construction.

Australia Memorandum of Intent was signed in July, 1981. Negotiations are under way over detailed conditions for the contract. The project is expected to ship 6.0 MMT a year to Japan.

Canada The project calls for a supply of 2.9 MMT a year starting around 1986. An application for export permission has been filed with the Canadian Government. The decision will come sometime in 1983.

(3) Possibilities of Project Now Under Examination, Being Materialized

The following four projects are now under study to supply LNG to Japan.

Sakhalin The Japan-Soviet joint project envisioned that 3.0 MMT will be shipped to Japan annually for 20 years from Chaivo offshore gas field off north-eastern Sakhalin. In August, 1982, the Soviet Union formally confirmed the volume of gas and oil reserves there and the development plan is being shaped. The Soviets hope to start supplying LNG by 1989, but due to a low-growth rate of LNG demand in Japan, it is likely that shipments will begin only after 1990.

Qatar has a plan to supply 6.0 MMT a year for 20 years to Japan from North Field off northern Qatar. QGPC is selecting a partner among foreign oil companies. QGPC had planned to start production in 1987, but there will be a big delay in the plan due to sluggish demand in Japan and Europe.

Thailand plans to export 2 to 3 MMT for 20 years to Japan or South Korea from an offshore gas field on the Gulf of Thailand. In July of this year, the Thai Government decided on the basic policy on natural gas exports and is selecting joint venture partners.

Indonesia plans to supply 6.0 MMT a year to Japan from D-Alfa concession field around Natuna Island. Although 75 percent of the gas exploited is carbon dioxide (CO_2), the bulk of gas reserves are expected. At present, EXXON is exploring the field.

Among the above four projects to be carried out after 1990, the total volume to be produced off Sakhalin will be shipped to Japan because of its nature as a government-level project. Therefore, Qatar, Thailand and Indonesia (Natuna) will compete with Alaska in the Far East.

The following chart summaries the LNG demand projections of MITI, Mitsubishi Research Institute, and other firms with expertise in the Japanese market contacting the Committee. From those figures the Committee has estimated the shortfall in committed supply which TAGS might fill:

Supply and Demand for LNG in Japan

(Millions of Metric Tons)

	1990		2000	
	Demand	Shortfall	Demand	Shortfall
MITI	43	9	50	31
Mitsubishi/C. Itoh	37	2	46	10-27
Mitsui	38.1	4	-	-
Marubeni	42-46	5-9	53-58	14-28
Sumitomo	39-44	2-7	-	-
Range	38.1-46	2-9	46-58	10-31

Shortfall figures for 1990 do not take into account the pending deal between Canada and Japan which would ship 2.9 MMT per year beginning in 1986 if the project is approved.

Higher ranges in the shortfall figures for 2000 assume that current contracts for delivery of LNG which expire before that time will not be extended.

After assessing the uncertain projections of supply and demand for Japanese LNG, Mitsubishi Research Institute concluded the following:

> "To raise marketability of North Slope gas, it will be proper to stress its merits over other competing projects. Although it will be needed to set attractive conditions in the contracts, it will far more necessary to emphasize such allures that the project will contribute to an improvement of Japan-U.S. trade imbalance, that it may trigger a relaxation of curbs on domestically-produced oil and that it offers unparalleled political stability as a supply source of LNG."

E. Projected Prices for LNG Landed in Japan

In order to establish a sense of TAGS economic feasibility, it was necessary to have estimates of the prices LNG will command in Japan in years to come.

Traditionally, LNG in Japan is priced at a calorie equivalent to oil. Oil prices, at the time of this study, faced continued uncertainty. Mitsubishi Research Institute provided the following estimates of oil and LNG prices, in nominal dollars, based on a conversion factor of 5.85 MMBTU's per barrel of oil. LNG prices are exclusive of regasification costs after landing in Japan.

YEAR	JAPANESE CRUDE PRICES	JAPANESE LNG PRICES
1982	$ 34.52	$ 5.90
1983	34.21	5.85
1984	35.50	6.07
1985	37.70	6.44
1986	40.34	6.90
1987	43.16	7.38
1988	46.18	7.89
1989	49.42	8.45
1990	52.88	9.04
1991	56.58	9.67
1992	60.54	10.35
1993	64.78	11.07
1994	69.31	11.85
1995	74.16	12.68
1996	79.35	13.56
1997	84.91	14.51
1998	90.85	15.53
1999	97.21	16.62
2000	104.00	17.78

F. Prospects of Demand and Supply of LNG in South Korea and Taiwan

1. South Korea — Present Situation

Korea Electric Power Corporation has agreed with PERTAMINA, Indonesia's state oil corporation, to import 1.6 MMT of LNG annually, produced in Arun, for 20 years starting from the middle of 1985. Later, the presidents of the two nations promised to add annual imports of 1.4 MMT of LNG for 1987 and afterwards. This plan was recently prolonged by two years with revised annual import volume of 2.0 MMT in and after 1987 and additional 1.0 MMT to be contracted from Indonesia for 1989 and later.

As is the case in Japan, LNG will be consumed in the power industry and city gas sector in South Korea. KEPCO will modify Pyeongtaek and Inchon Thermal Plants to burn LNG as well as oil. By 1987, four units with generating capacity of 350 MW each of Pyeongtaek Plant and two units with 250 MW each of Inchon Plant will be converted similarly. The remaining two units with 325 MW each of Inchon Plant will be modified by the end of 1989. As a result, generating capacity of LNG plant will increase to 2.55 BW by the end of 1989.

Of the 2 MMT to be imported from Indonesia, 1.6 MMT will be priced at $5.78/MMBTU on F.O.B. basis and the rest remains undecided.

2. South Korea -- Prospects

The Energy Forecasts by 1991, compiled by the South Korean Government, show a basic policy under which alternative energy sources, mainly nuclear energy, will be actively developed to reduce Korean dependence on oil. As for LNG, the demand in 1991 is set at 3.0 MMT and this corresponds with the prospective import volume from Indonesia, as seen in 2-1.

According to the forecast, LNG demand in the power industry will be cut to 1.9 MMT in 1991 from 2.7 MMT in 1989, while that from households will increase to 1.1 MMT from 0.3 MMT, because excessive LNG will be converted for household use after a nuclear power plant starts operation. This indicates city gas suppliers' positive attitude towards introducing natural gas. Therefore, in the 1990s if construction of nuclear power plants is badly behind schedule or gas demand from households and industry firms up, there is a possibility that additional 1.5 MMT of LNG will be needed.

Energy Forecasts of the South Korean Government

	1982		1991	
Oil (million b.p.d.)	0.4348	(59.4%)	0.605	(43.6%)
Imported LPG (MMT)	0.2	(0.8)	1.0	(2.3)
LNG (MMT)	0		3.9	(4.9)
Coal (MMT)	30.7	(36.9)	49.2	(34.7)
Hydroelectric (MW)	249	(1.4)	494	(1.3)
Nuclear (MW)	352	(1.7)	5110	(13.2)

3. Taiwan

There is little information on LNG in Taiwan available. Annual natural gas production is estimated at 1.67 billion cubic-meters (59 billion cubic feet) against confirmed reserves of 24 billion cubic-meters (847 billion cubic feet) and, if production continues at the present level, the country's reserves will be exhausted in 15 years or so.

Taiwan plans to increase natural gas production sharply in 1985. If the plan fails, there will be a possibility that Taiwan will introduce LNG at an earlier date than expected.

At present, it is supposed that Taiwan will have LNG demand of 1.0 MMT, equivalent to the present natural gas production level, around 2000.

4. Prospective Supply to South Korea and Taiwan

Indonesia agreed to supply LNG to South Korea. When LNG demand will increase considerably in South Korea and Taiwan, the two countries are now expected to view some of three projects -- Qatar, Thailand and Indonesia (Natuna) -- as supply sources.

As the LNG demand in Japan is predicted to increase at a slower rate than initially expected, it will be difficult for Japan to import all the volume to be produced in Qatar and Indonesia (Natuna) during a period since they will have large production capacity of 6.0 MMT each. Therefore, it will be highly possible that some of the LNG will be shipped to South Korea and Taiwan.

Although South Korea is talking with Thailand on LNG imports, Thailand's 3 MMT's will be too large to be imported solely by South Korea. Therefore, Thailand may seek its export possibility not only to South Korea but also to Japan.

IV. The American Market for North Slope Gas

A. Alaska

While expected levels of demand in Alaska are small to the point of insignificance in adding to the financial viability of the Trans-Alaska Gas System, the system itself can make a large contribution to solving Alaska's needs for home heating fuel and electric power generation. At the same time, proponents of value-added industries in the state have forseen the use of North Slope methane and gas liquids for creation of products such as methanol for export.

Coincident with this study by the Governor's Economic Committee, the Alaska Power Authority and Ebasco, its consultants, have looked at the use of North Slope gas for instate power generation.

Fairbanks, Alaska's second largest city, is in dire need of low cost power. This project would make gas supplies available to the community for power generation. Gas can also be used as a feedstock for added value processing, such as in a methanol facility. Methanol could be used in motor vehicles and other internal combustion engines in Alaska or exported.

Anchorage's home heating needs and electric power generating capacity are currently met by gas production from the Cook Inlet. However, over the life of TAGS, North Slope gas could make an economic contribution.

Other cities and towns in the state could potentially be served by either the Alaska Power Authority's proposed intertie between Anchorage and Fairbanks or through shipments of less volatile North Slope gas products such as propane in rail tank cars, ships along the coast, or barges in the river system.

B. The Lower 48 States

Two possible sites to bring LNG from Alaska into the West Coast have been brought to the Committee's attention as having potential to receive large scale ships and to hook into currently existing U.S. pipeline systems. Overall demand in the short term from each of these areas looks small today, but eventual changes in the U.S. demand picture for LNG could be met in this manner.

1. Point Conception

Pacific Alaska LNG Associates has spent a total of almost 400 million dollars to design, engineer and gain permits for a project which would establish an LNG receiving terminal with connection to existing natural gas trunk lines, near Point Conception, California.

Although the company recently received a final siting approval from the California Public Utilities Commission (CPUC), it has filed with the CPUC to have the project "preserved for future use". The company indicated that California's natural gas needs are currently being met from lower 48 sources, along with some Canadian and Mexican supplies. It reported the project is scheduled to begin construction in 1986 for completion in 1990 and that sources of LNG in addition to those contracted from Alaska's Cook Inlet will be sought to feed into the California receiving terminal.

Currently PacAlaska LNG has secured 144 million cubic feet per day or slightly over two thirds of the reserves necessary to cover the first phase of 200 MMCFD. The second phase is scheduled to process an additional 200 MMCFD. No contracts have been signed to supply any part of the phase two demand. In addition to the scheduled Alaska supply, Pac Alaska LNG has signed a letter of agreement (due to expire in 1983) with Indonesian sources for approximately 555 MMCFD.

The proposed terminus has a processing limit, under California law, of 1.3 billion cubic feet per day. Of this total limit, supply commitments total 644 MMCFD.

Assumming Indonesian commitments hold, therefore a window of 656 mmcfd would exist for North Slope gas or other supplies to reach the limits of the facility. Uncertainty continues, however, as to whether the California market will present prospective demand in 1986 to bring about any financing and construction of the PAC Alaska project.

2. Port of Bellingham

Bellingham, Washington has, for the past 20 years, sought to serve Alaska as a southern terminus for a major transportation system joining Alaska and Washington.

In connection with the committee's work authorities of the Port of Bellingham have requested that it be considered as a potential terminus in the Lower 48 to receive LNG shipments from the proposed Trans-Alaska Gas System.

The Port's Cherry Point area has several features necessary for the siting of a major receiving terminal. Those features include deep water close ashore, large upland sites, heavy impact industry zoning in place, and industrial utilities. As a primary additional feature, the site is currently served with a 16" diameter high pressure natural gas pipeline connecting to the natural gas grid system serving much of the Pacific Northwest.

V. The Petrochemical Opportunity

Alaska has a number of unique features which can attract petrochemical development to serve the entire Pacific Rim. Just as the Gulf Coast of Texas and Louisiana has made those states providers to the Atlantic family of nations and their need for petrochemicals during the last generation, Alaska has the potential to compete as a "Gulf Coast of the North" to provide for the next generation in the Pacific.

Among the features which lead to the possibility of petrochemical development in Alaska are:

1. The immense size of the North Slope gas reserves. At 26 trillion cubic feet, Prudhoe Bay has the largest quantity of gas in a single place on the continent.

2. The availability of an adequate supply of fresh water for processing.

3. The availability of large tracts of land which are suitable for plant development.

4. The State's geographic position, halfway between the United States and Asia, and its ability to serve both markets.

The North Slope natural gas reserve is rich in natural gas liquids (NGL). These liquids include ethane, propane, and butane which are the key petrochemical feedstocks today and for the future.

A. Ethylene Production

The initial phase of petrochemical development would be the construction and operation of an ethylene plant. While all natural gas liquids are excellent petrochemical feedstocks, ethane is expected to be the most attractive component for petrochemicals in Alaska. Ethane produces a higher yield of ethylene based products than propane and butane. An ethylene plant would be the key unit of a petrochemical industry. Potential byproducts from first phase processing at an ethylene plant would include:

Ethylene	Ethylene Glycol
Polyethylene	Ethylbenzene
Ethylene Dichloride	Polystyrene

Downstage processing creates a multitude of products ranging from polyester resins to plastics, as detailed in the accompanying fold-out exhibits.

The 1981 Dow-Shell Study of the feasibility of establishing a petrochemical industry in Alaska summarized demand and capacity projections for ethylene in the Pacific Rim. Those findings are reprinted as follows:

1. "There should be a need for additional ethylene capacity (with associated derivatives) by the late 1980's to supply the Pacific Rim markets -- western U.S. and Canada, the Far Eastern and Southeast Asian countries, Mexico and the western part of South America.

2. "The major areas requiring imports of ethylene derivatives will be Japan and the Asian countries.

3. "Major areas with export capability will be the Mid-East and Canada -- both based on relatively low cost feedstocks -- and the U.S. Gulf Coast.

4. "Mexico and South America are seen as short-term exporters of a few petrochemicals, although internal and regional demand should consume most of their increases in capacity.

5. "The Australian area is expected to be in balance, although some potential would exist for export of a few products from Australia after 1985.

6. "The Indian sub-continent is forseen to continue in balance -- neither a supplier of ethylene nor a significant market."

B. Japanese Market

Japan's current imports of natural gas liquids, primarily liquified propane and butane (LPG), has increased steadily and is projected to continue increasing.

LPG IMPORTS BY JAPAN

1980	10	million metric tons
1982	11.5	million metric tons
1990E	20	million metric tons

Potential TAGS gas liquids (LPG production)

Phase 1	Phase 2	Phase 3
1.1 Million MT	1.9 Million MT	3.0 Million MT

Includes propane, butane, pentanes and heavier.

From table 5, of Dillon, Read's economic report where costs of a pipeline tariff and fractionation of natural gas liquids were estimated, the figures have been converted here into metric tons.

Prospective NGL costs per metric ton delivered to South Alaska

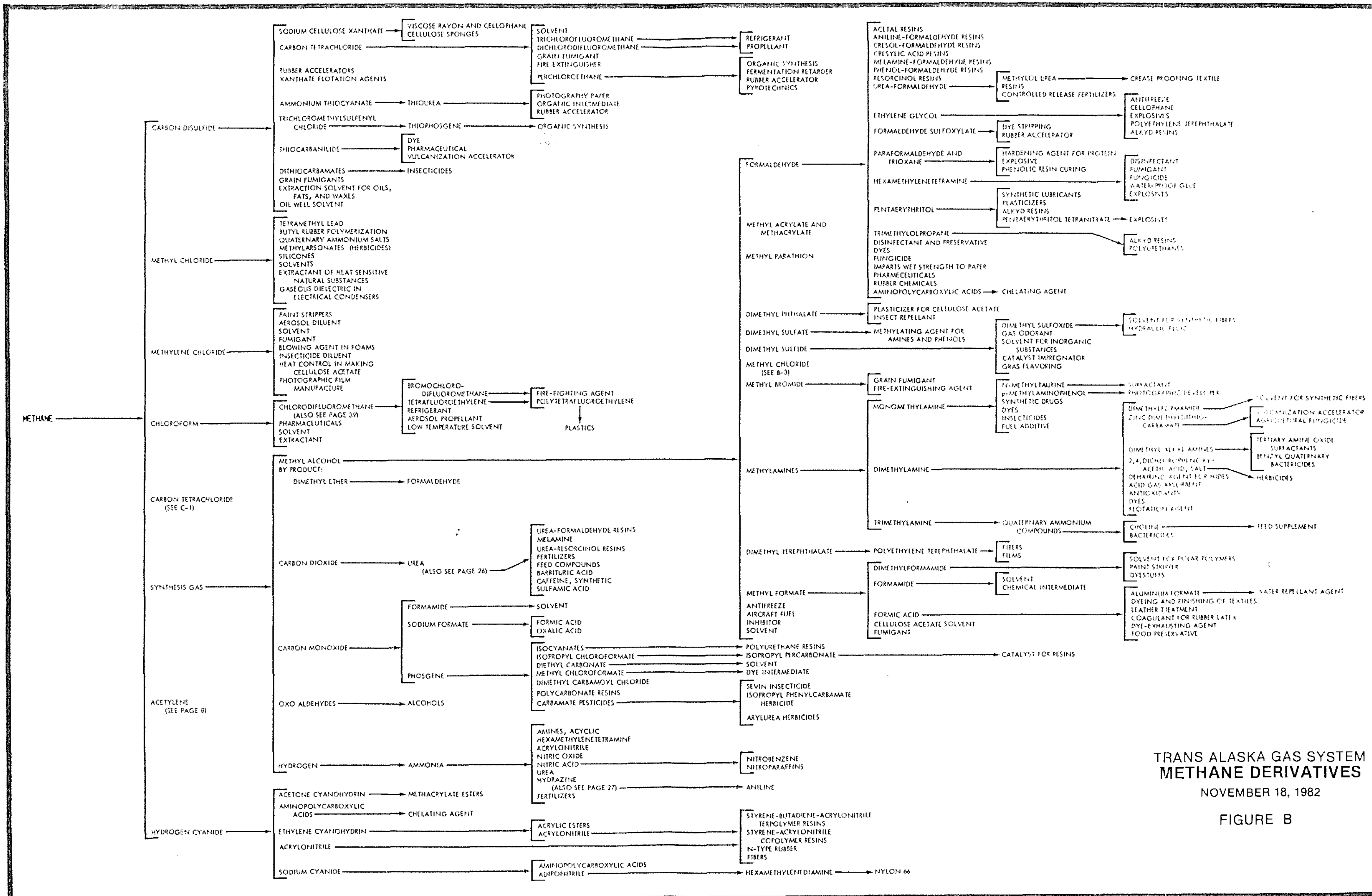
(1988 Nominal Dollars)

Total System

	Lower Tariff	Higher Tariff
Propane	224.81	312.25
Butane	259.05	359.76

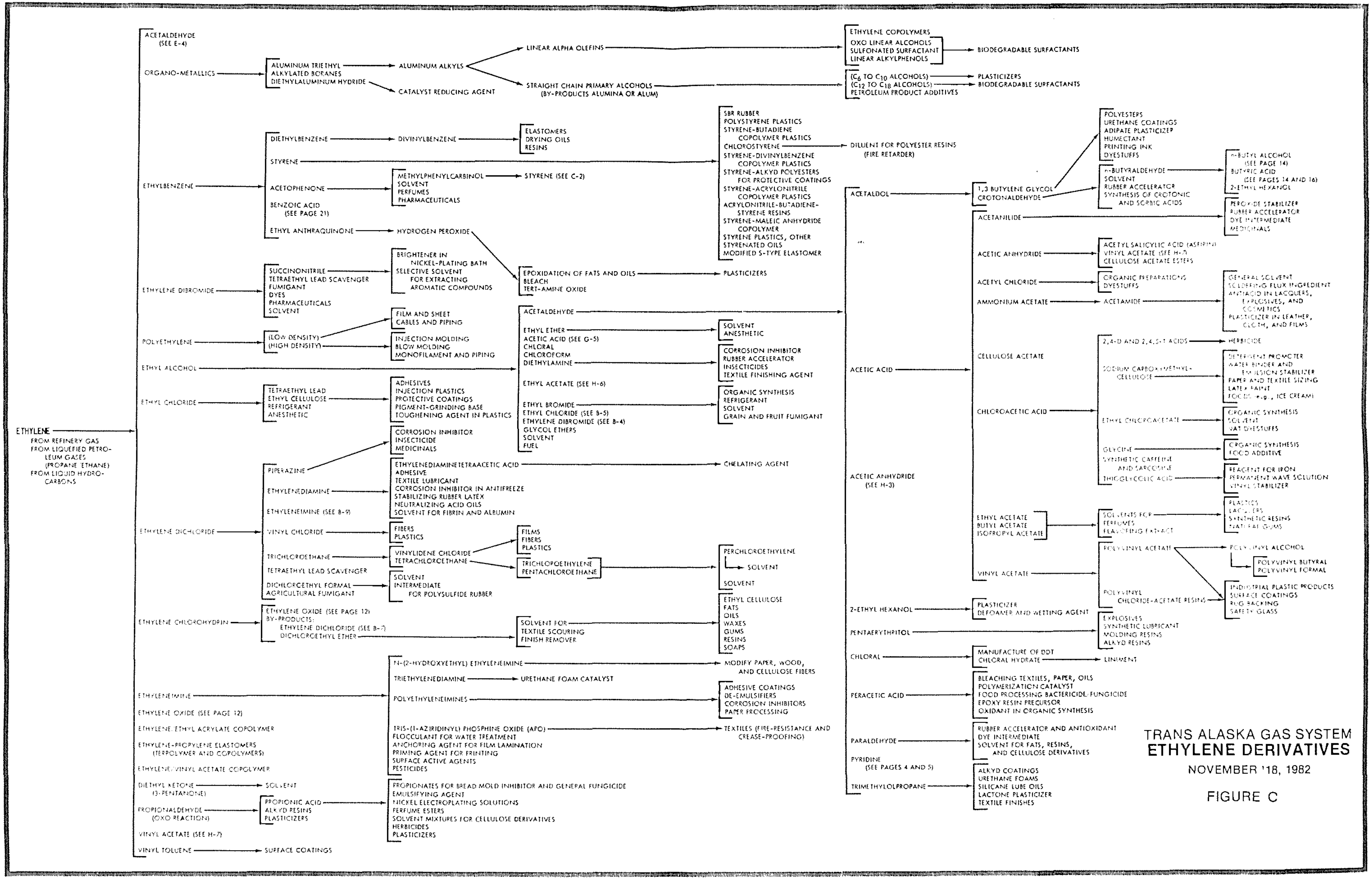
Phase 1 System

	Lower Tariff	Higher Tariff
Propane	300.61	407.94
Butane	346.36	469.93



TRANS ALASKA GAS SYSTEM
METHANE DERIVATIVES
NOVEMBER 18, 1982

FIGURE B

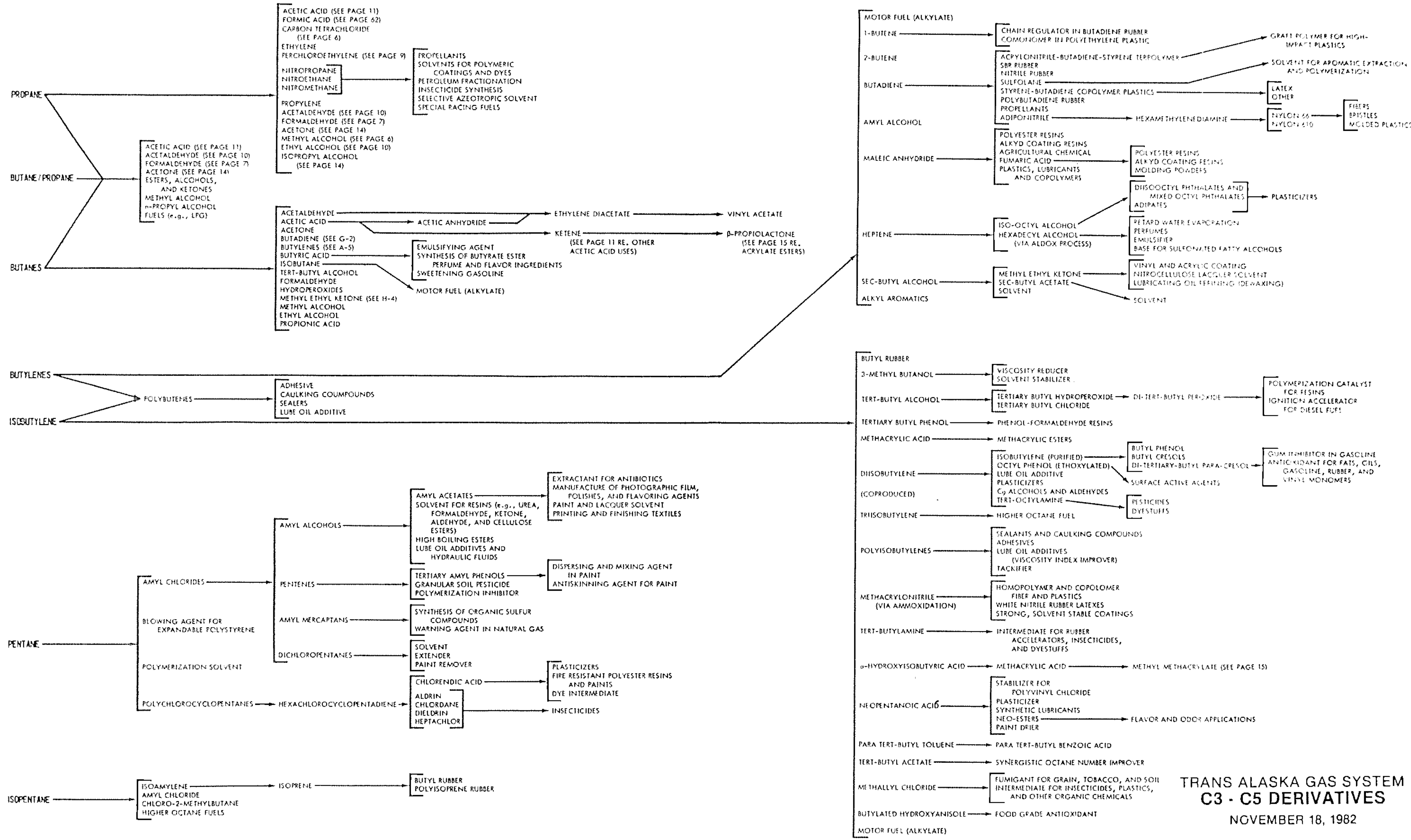


TRANS ALASKA GAS SYSTEM

ETHYLENE DERIVATIVES

NOVEMBER 18, 1982

FIGURE C



TRANS ALASKA GAS SYSTEM
C3 - C5 DERIVATIVES
NOVEMBER 18, 1982

FIGURE D

To establish marketability for LPG shipments, additional costs of shipping from South Alaska, receiving in Japan, and special handling must be compared with petroleum-based naptha costs, the competitive commodity.

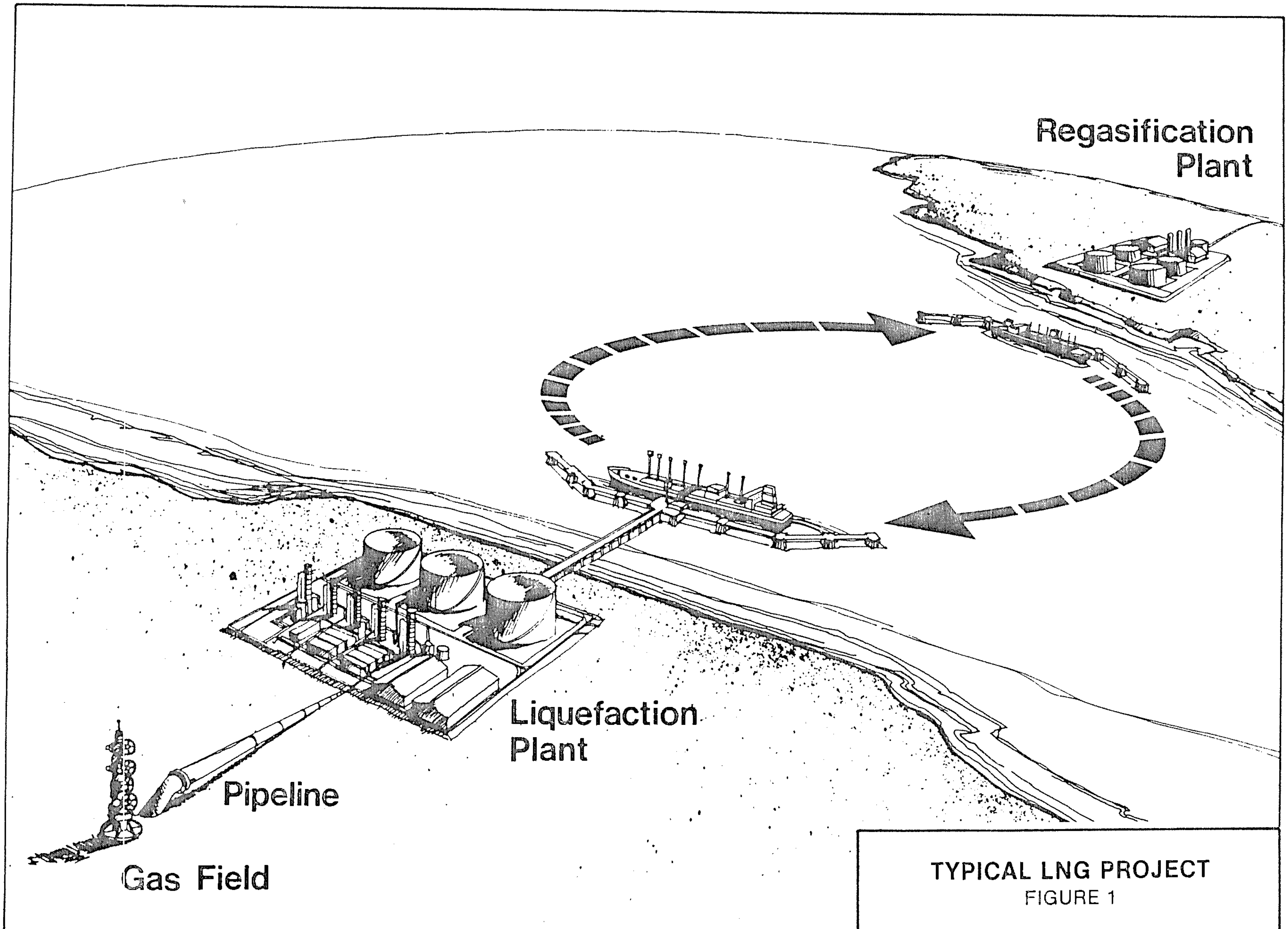
Ethane, for the purpose of this study, has been assumed to be shipped as a component of LNG. It can be shipped separately as liqueified ethane gas (LEG). Alternatively, an ethylene plant might be located in South Alaska to make shipments of unprocessed ethylene into the growing Japanese market.

ETHYLENE CONSUMPTION BY JAPAN	
1980	9 billion pounds
1982	10 billion pounds
1990E	14 billion pounds

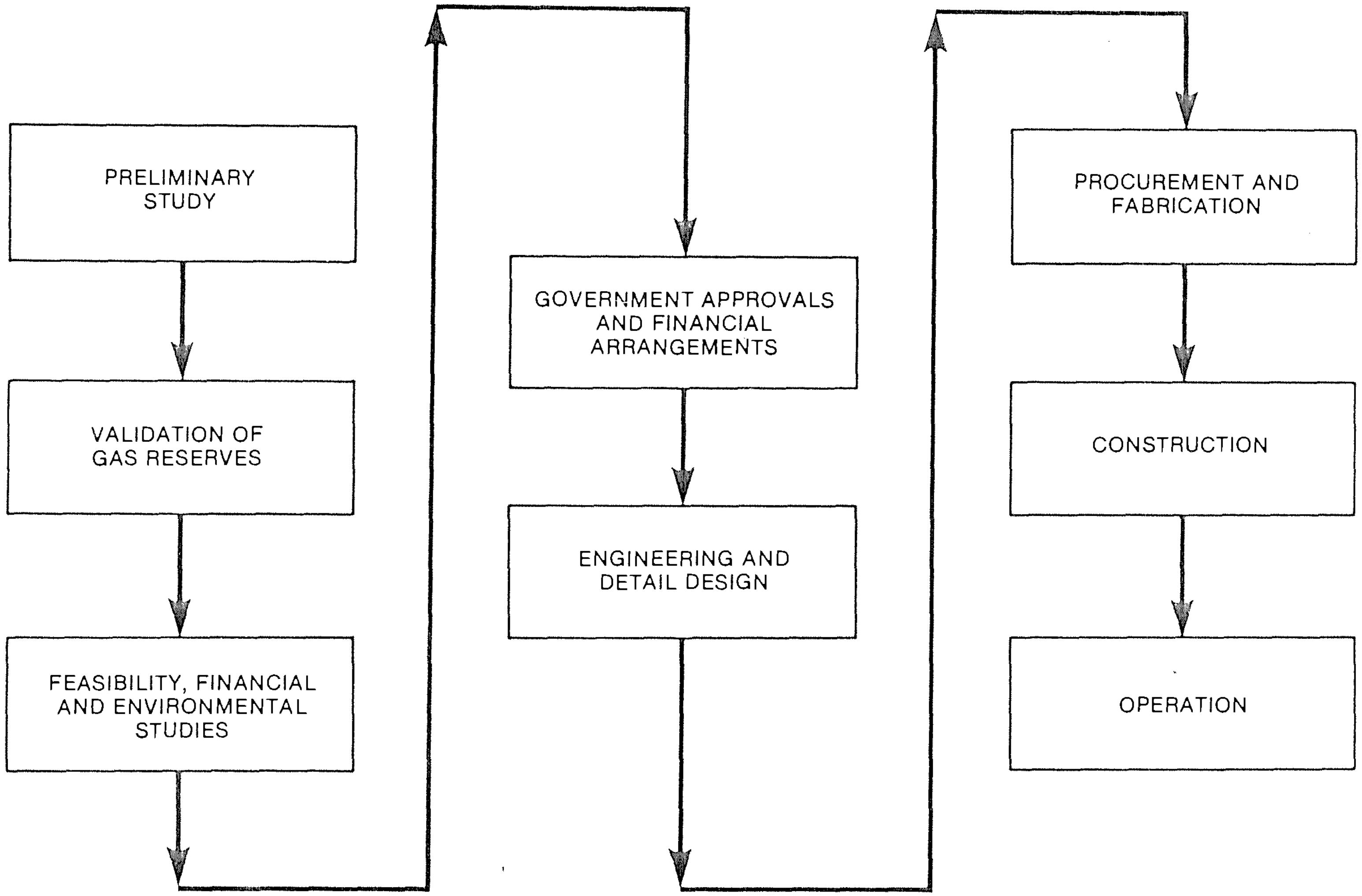
Alaska's ethylene production potential from the proposed TAGS project would be in excess of 2 billion pounds per year of ethylene as various derivatives. It is conceivable that with Japan's relatively high level of ethylene consumption the quantities produced from an Alaskan ethylene plant could be absorbed into present Japanese supplies. To do so, however, it must also be competitive with naptha based derivatives.

Mitsui and Company, in a November report to the Committee addressed the issue of naptha prices in Japan and LPG/LEG markets as follows:

"In order to come up with more accurate estimates of what prices would be competitive with imported naphtha at plant inlets, we would have to estimate the costs of handling LPG and LEG in Japan, taking into consideration the very numerous factors involved. However, we would like to point out that the importation of LPG for LEG would involve not only the handling costs but also the huge capital expenditures that would be required for the construction of LPG or LEG unloading facilities and storage



TYPICAL LNG PROJECT
FIGURE 1



TYPICAL LNG PROJECT DEVELOPMENT
FIGURE 2

tanks. A few petrochemical complexes in Japan have their own terminals for receiving LPG from ocean-going tankers, but there is no terminal for receiving LEG in Japan because LEG has never been exported to Japan.

"To summarize, we can state the following general conclusions:

(1) "The future prices of petrochemical feedstocks in Japan will be determined by the prices of naphtha, and in turn, naphtha prices will be determined by world oil prices.

(2) "LPG could be exported to Japan as a competitively priced petrochemical feedstock, but LEG could not.

(3) "Ethane gas could be exported to Japan as a fuel (but not as a petrochemical feedstock) in the form of LEG, or it could be transformed into ethylene in Alaska, and Alaska could export ethylene to Japan as an intermediate raw material for petrochemical production."

C. U.S. Market

While the current U.S. market for NGL's is over-supplied, it is important to note that U.S. domestic NGL production has declined since the mid 1970's. In light of decreasing domestic production the potential availability of such a large supply in a politically stable location may prove attractive to the petrochemical industry. This fact provides significant benefits to an Alaskan hydrocarbon development.

VI. Shipping

A. Overview

In a typical international LNG project, natural gas is transported via pipeline from gas fields to a liquefaction plant at an ocean port location. Here it is refrigerated to about -260F, at which point it becomes a liquid and shrinks to about 1/600th of its gaseous volume. The liquefied gas is stored at atmospheric pressure in heavily insulated tanks located at the marine loading terminal until it is loaded into specially designed LNG vessels. The LNG vessels then transport the LNG to a marine receiving terminal, where it is heated, vaporized and delivered to a pipeline transportation system and ultimately to the consuming market. A typical LNG transportation system which does not include conditioning and separation of gas liquids, is illustrated in Figure 1.

Most base-load LNG projects, as opposed to peak-shaving LNG projects, have certain features in common regardless of the origin of supply and the market served. They are complex, involve large quantities of energy and equipment, and require multiple governmental approvals, large capital investments, and long lead times to implement (Figure 2). Furthermore, they usually have several participants and are generally international in nature. The resulting mix of these elements gives each project a unique character.

One of the distinguishing features of an LNG project is the large capital investment required for the project facilities. Costs vary greatly according to the particular project, but usually run into the billions of dollars. To deliver energy at an acceptable cost requires that the recovery of the investment be spread out over long periods of time, generally from 15 to 20 years. Protection of this capital investment demands project facilities that are reliable and which can continuously produce LNG throughout the life of the project.

The distance of the natural gas reserves from an acceptable market has a direct bearing on the delivered price of the gas. The more distant the gas source, the more shipping capacity that is required. This additional capacity can be provided in the form of larger vessels, more vessels and/or increased vessel speed, all of which directly affect the LNG shipping cost.

Since the volume of LNG to be transported and the distance between the loading and unloading terminals is fixed, the shipping capacity - in terms of vessel speed, size, and number - becomes the transportation system variable and is, therefore, the optimization focus for an LNG marine transportation system. These elements must also be brought into a balanced interface with the terminal and plant design variables.

B. Marine Loading and Unloading Terminal Characteristics

The marine loading and unloading terminals for an LNG transportation system are comprised of LNG storage and (un)loading facilities (LNG storage tanks and LNG cargo (un)loading lines) plus the offshore vessel berthing and access facilities.

The location of the marine loading and unloading terminal sites must satisfy requirements dictated by the design, construction, and operation of the LNG and regasification plants, the LNG marine terminal with attendant LNG storage and (un)loading facilities, as well as by the design and operational characteristics of the LNG vessels. The following general characteristics of a marine terminal have been followed by the industry in the construction of the existing three major U.S. receiving terminals plus the existing loading terminals in Indonesia, Algeria, and Abu Dhabi:

- The terminal sites should be as close as possible to the plants. A minimum water depth of maximum vessel draft plus five feet at mean lower low water (MLLW) is desirable. This water depth minimizes the impact on the environment so as to preclude the requirement of dredging.

- The marine terminal should be as close as possible to shore to minimize liquid line length and resulting LNG product losses, and to further minimize the cost of the access pier to the berths.

- Desirable characteristics for sea bottom soils should be granular soils or medium to soft clays. Because of the structural system normally used in the design of most terminals, it is desirable to have bedrock located at a reasonable depth below sea bottom.

- No active fault zones should be located on or adjacent to the marine terminal or plant site.

- To minimize ship downtime during loading and unloading operations, there should be a minimal occurrence of excessive wave heights and wind speeds. Studies and operating experience have indicated that LNG (un)loading operations may have to cease when wind and wave conditions become excessive.

- As a preliminary criterion, areas for vessel manuevering should provide a channel width of three times the width (beam) of the vessel when traffic is limited to one-way, and six times the width of the vessel when two-way traffic is expected. The minimum diameter of any turning basin, if needed, should be equal to 1-1/2 to 2 times the length of the vessel.

The required characteristics of navigable waterway approaches for LNG trades into newly designed ports and terminals are more stringent than for existing ports and new terminals. Where possible, it is desirable to align the terminal's approach with the following criteria:

- The size and depth of the approach channel should be the same as that at the berth, with a minimum channel width of three times the beam of the vessel for one-way traffic and six times the beam for two-way traffic.

- It would be desirable to have no sharp turns in the channel, and overhead structures should have a minimum air clearance consistent with local regulatory requirements.

- Vessel traffic patterns require minimal marine traffic interference and well defined marine traffic patterns. Traffic safety systems have become preferred by most areas where there is a large amount of marine traffic through a narrow waterway.

- Sufficient aids to navigation should be available in areas near the marine terminals in addition to the approach to the terminals.

- Anchorage areas should have moderate water depths, good shelter and ample manuevering room. To obtain good holding power, a ship generally lets out a length of chain equal to five to seven times the depth of the water. Most large vessels carry approximately 1000 feet of anchor chain.

C. LNG Marine Transportation System Parameters

1. Fleet Capacity

The transportation capacity of the fleet - number of vessels, vessel cargo capacity, and vessel service speed - is based on the project LNG transportation requirements (design material balance), trade route characteristics, and the project and LNG vessel design and operational parameters.

a. LNG Transportation Requirements

The LNG transportation requirements for the project are based on three levels of LNG production at the Nikishka plant which are brought on-stream in build-up phases with two year intervals between each phase. Further, the product may be shipped to four alternate unloading terminals located at: Osaka, Japan, Inchon, Korea, Pt. Conception, California and Bellingham, Washington.

The LNG quantities to be loaded and transported are as follows:

LNG produced –	Phase I	Phase II	Phase III
MMSCF/D	736.2	1,356.1	2,193
MMM BTU/D	783.3	1,442.9	2,333
M^3 Liquid/Yr	12,292,809	22,642,012	36,617,945

Operationally, the cargo tanks of the ship are filled at the Nikishka LNG Plant to approximately 97.5 percent of rated volumetric capacity. The tanks are emptied at the unloading terminal, except for a small fraction of the cargo, or heel, which is left on board to cool the cargo tanks during the return voyage to Alaska. The tanks are intermittently spray-cooled throughout the ballast voyage to a temperature of minus 220^{O}F to assure the vessel is ready for immediate loading upon arrival at the Nikishka terminal.

During both the loaded and ballast voyages, a portion of the LNG boils off due to heat influx through the cargo tank insulation and into the ship's cargo tanks. This boil-off is used as boiler fuel en route.

b. Trade Route Characteristics

The trade routes for the Trans Alaska Gas System extends from a marine terminal and liquefaction facility located near Nikishka inside Cook Inlet to alternate marine terminals and vaporization plants which could be located at: 1) Osaka, Japan, 2) Inchon, Korea, 3) Bellingham, Washington, and 4) Point Conception, California. The one-way distances between the terminals are as follows:

	Osaka, Japan	Inchon, Korea	Pt. Concep-tion, CA	Belling-ham, WA
FROM Nikishka LNG Loading Terminal	3600*	4040*	2100*	1400*

*Nautical Miles

Fleet operations en route are affected by weather, sea conditions, visibility, navigational restrictions and regulations, as well as vessel traffic density. Specific en route wind and current conditions for winter and summer are not available for this report. Also, the specific operational considerations for the five ports are not available for this report.

2. LNG Vessel Design and Operating Assumptions

The following assumptions regarding the vessels and their operation will be the basis for this study which determines the preliminary configuration of the fleet:

- Essentially, all LNG vessels are mechanically and geometrically similar, i.e., steam turbines, single shaft, approximately 40,000SHP, etc.

- All LNG vessels comprising the fleet are generally similar in terms of cargo capacity (126,600 m^3 average), service speed (18.5 knots), and operating characteristics.

- Each LNG vessel will be loaded to 97.5% of its capacity (123,500 m^3).

- The assumed LNG cargo daily boiloff rate of 0.15 percent of the LNG cargo loaded.

- Each LNG vessel is in operating service an average of 329.7 days annually. The remaining days are utilized for planned maintenance and for random repairs and delay (Table 1).

- Loading and unloading operations are conducted in the respective terminals 24 hours a day without allowing for nighttime restrictions on LNG vessel movement.

- Sufficient drydock space and related maintenance facilities are available upon demand within reasonable distance of the trade route to service the fleet within the specified times.

TABLE 1 - SHIP UTILIZATION

			DAYS PER YEAR
ASSUMED OPERATING YEAR			365
LESS: Ship out-of service time			
Drydock schedule[a]			
Drydock time	14.0		
Cooldown[b]	2.3		
Diversion en route[c]	4.0		
Total drydock time		20.3	
Random repair and delay		15.0	
Total ship-out-of-service time			35.3
ANNUAL SHIP UTILIZATION			329.7

[a]Each vessel is drydocked either on the west coast of the United States or in a foreign shipyard in either Japan or Korea.

[b]The total time of 2.3 days (54 hours) is divided into two categories:

1) Purging of inert gas (24 hours)
2) Cooldown (30 hours)

[c]Diversion en route is the difference in the following:

Voyage time from the loading terminal to drydock to the Nikishka LNG Plant less normal ballast voyage time.

- The LNG fleet exclusively serves the Trans Alaska Gas System Project.

- Even though an existing LNG trade operates at the Osaka terminal this project does not share the marine facilities at the four assumed unloading terminals with other LNG projects.

Additional operating assumptions for the fleet with respect to the trade route and the loading and unloading terminals are as follows:

- The distance between the ports as shown in Table 2 considers the total distance the vessels must travel, most of which time they will operate at their service speeds. An adjustment must also be made to the voyage time for the distance each vessel must travel to and from the terminals at reduced speeds.

- The port event times shown in Table 3 are the average expected times required for a vessel to complete each activity in each of the ports and terminals. The times required for pilot pick-up, bay ingress/egress, tie-up, and cast-off are the same for all LNG vessels, regardless of capacity. The time required to load and discharge LNG cargo is the same for each vessel.

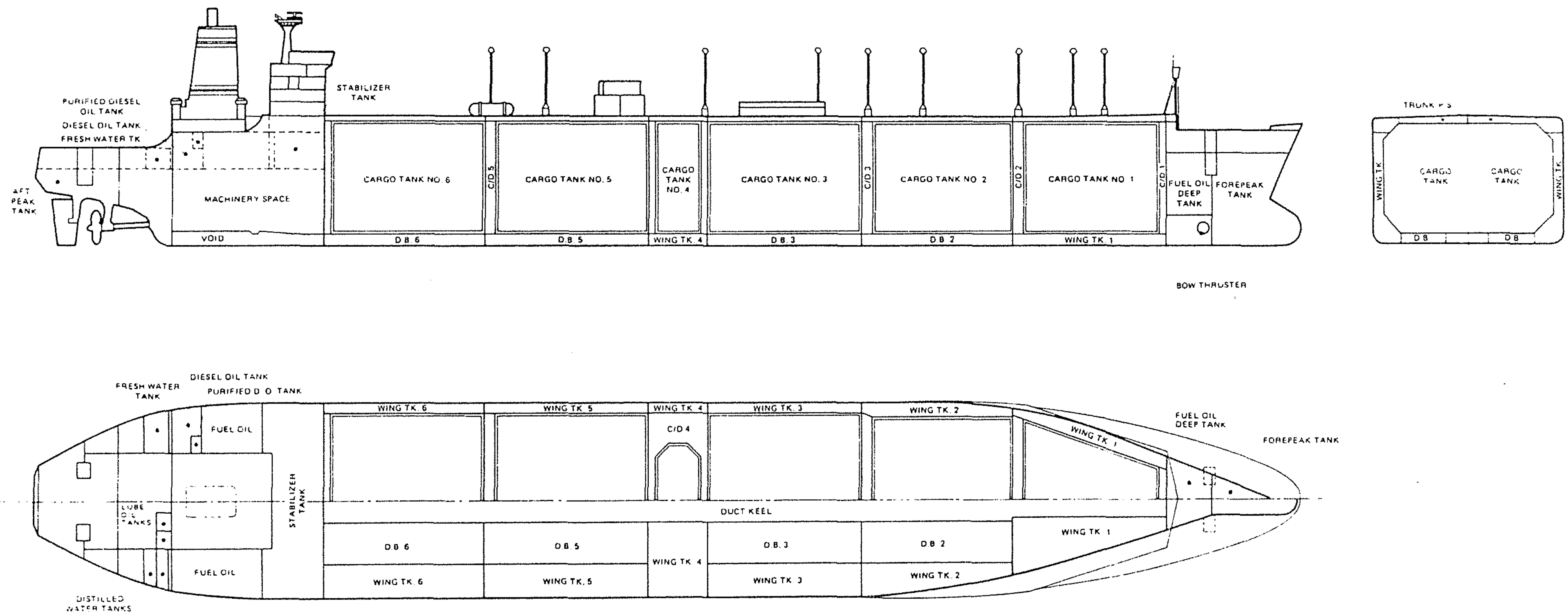
Table 2 - Trade Route Distances
(Nautical Miles)

Nikishka To:[a]	Osaka, Japan	Inchon, Korea	Bellingham, Washington	Pt. Concep- tion, CA
One-way distance	3,600	4,040	1,400	2,100
Distance from Nikishka to Mouth of Cook Inlet	50	50	50	50
Distance from Port Entrance to Unloading Marine Terminal	100	10	150	10

[a]Source: Distance Between Ports, 1976 which provides mileages from junction points and ports

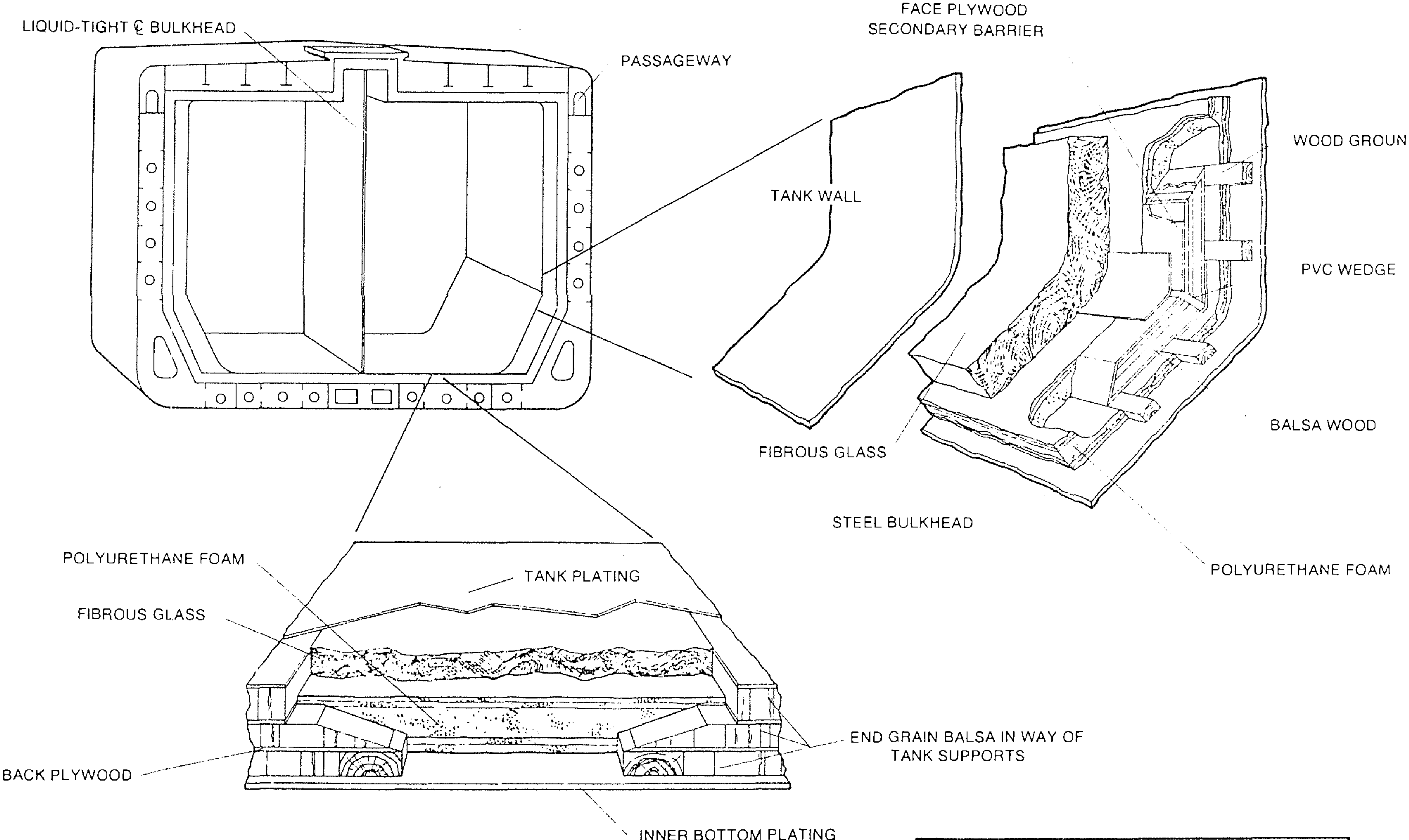
Table 3 - Estimated Average Event Times For Port Operations

POINT CONCEPTION AND BELLINGHAM	
Tie-up	.28
Unload	.50
Cast-off	.22
Delays	.67
Total Port Time	1.67 Days/Trip
INCHON	
Tie-Up	.26
Unload	.50
Cast-off	.23
Delays	.64
Total Port Time	1.63 Days/Trip
OSAKA	
Tie-up	.26
Unload	.50
Cast-off	.23
Delays	.65
TOTAL Port Time	1.63 Days/Trip
NIKISHKA	
Tie-Up	.27
Load	.50
Cast-off	.23
Delays	.95
TOTAL Port Time	1.95 Days/Trip



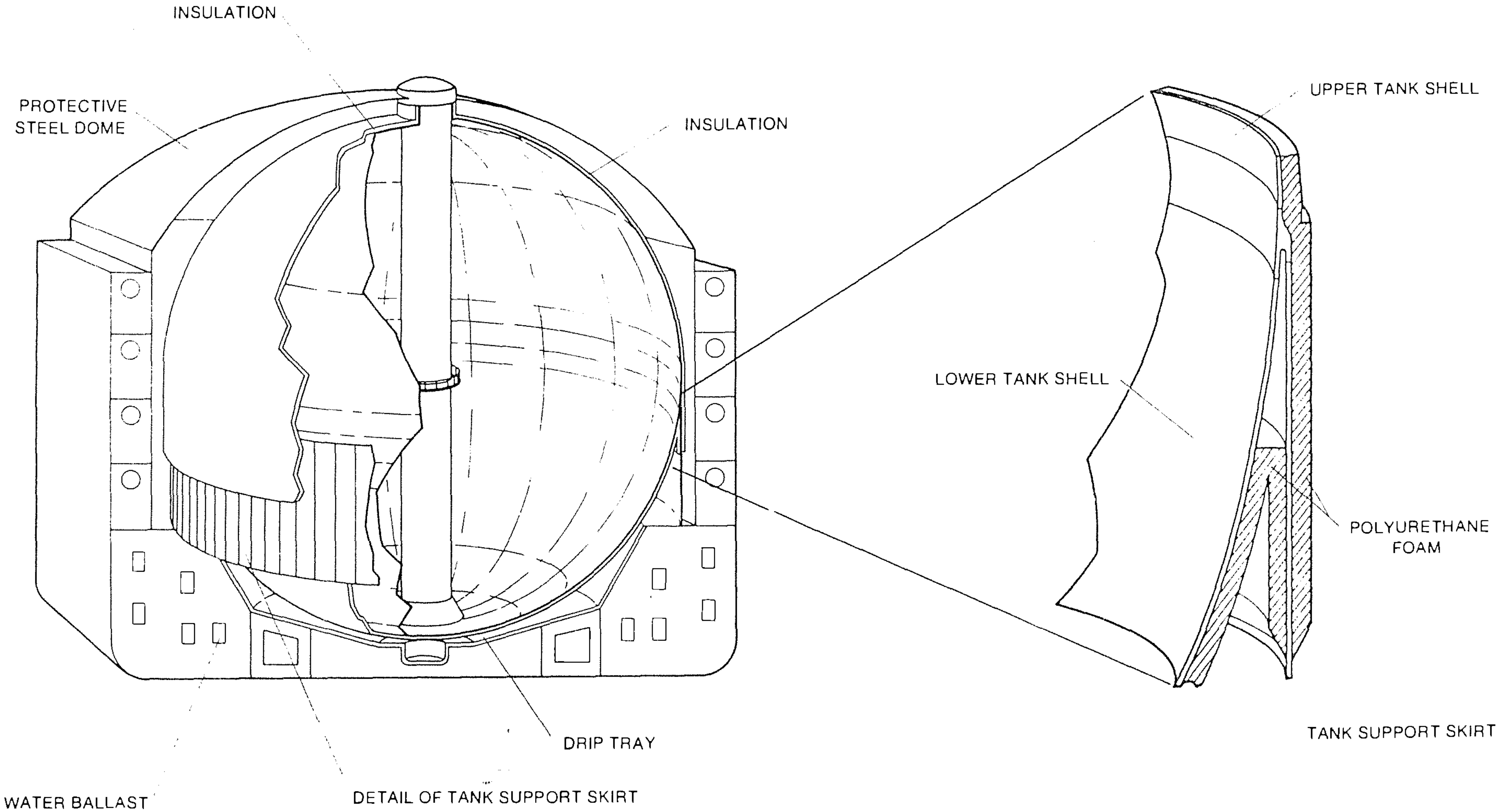
GENERAL ARRANGEMENT OF TYPICAL LNG CARRIER

FIGURE 3



CONCH FREESTANDING TANK DESIGN

FIGURE 4



KVAERNER - MOSS SPHERICAL TANK DESIGN
FIGURE 5

3. LNG Plant Operating Assumptions

Annual maintenance for the LNG plant should begin approximately at the same time the first LNG carrier enters annual drydocking.

4. Loading and Unloading Terminal Design and Operating Assumptions

The vaporization capacity of each unloading terminal is assumed to be such that the LNG carriers will not be delayed due to insufficient unloading and storage capacities.

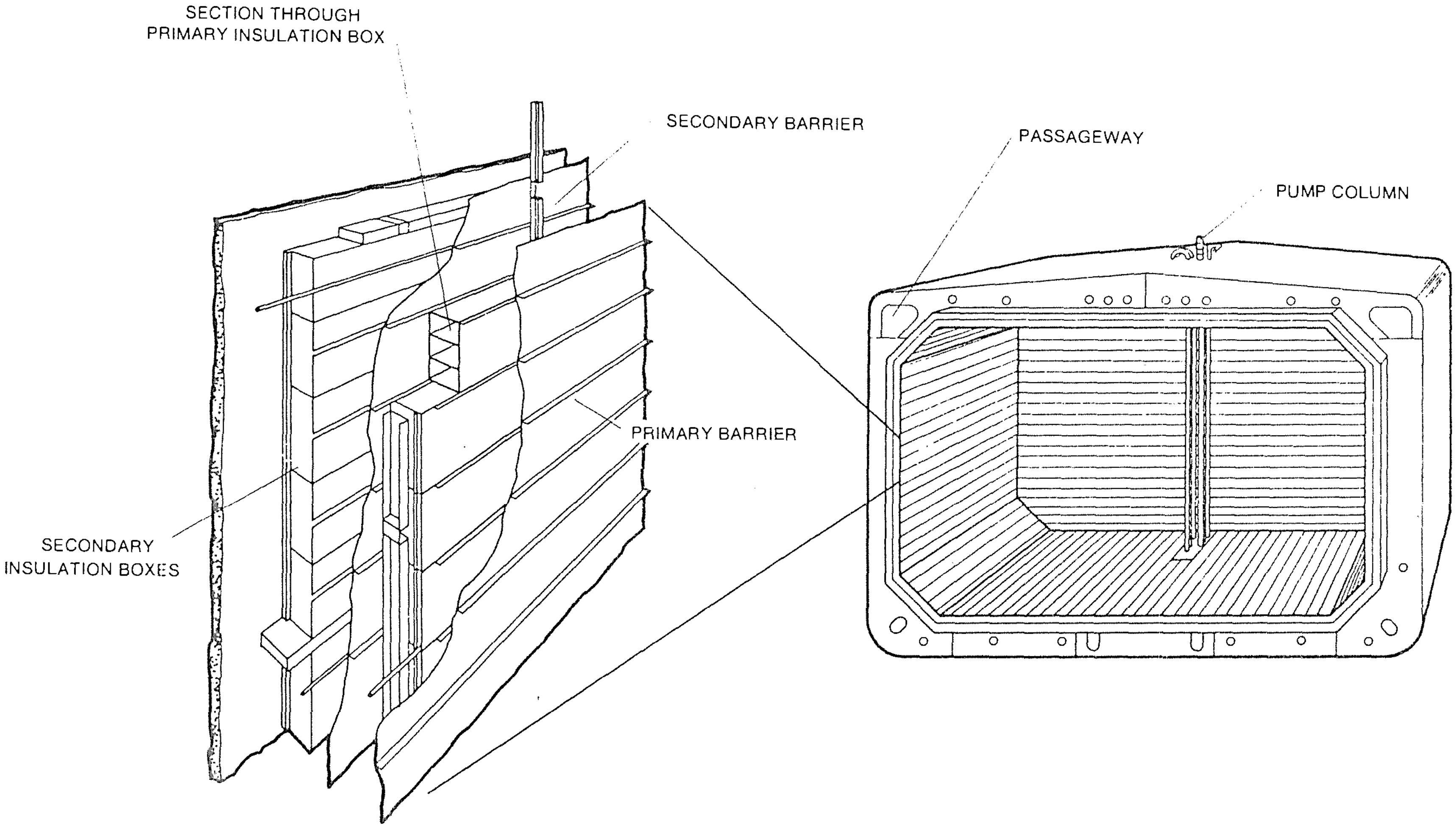
It is assumed that the terminal capacities of each location are as follows:

	Nikishka	Pt Conception	Bellingham	Inchon	Osaka
Number of Berths	2	2	2	2	2
Number of cryogenic liquid lines between terminal and LNG storage tanks	2	1	1	1	1
Loading and unloading rates m^3/hr	11,500	12,000	12,000	12,000	12,000
LNG storage capacity $m^3 \times 10^3$	300	300	300	300	300

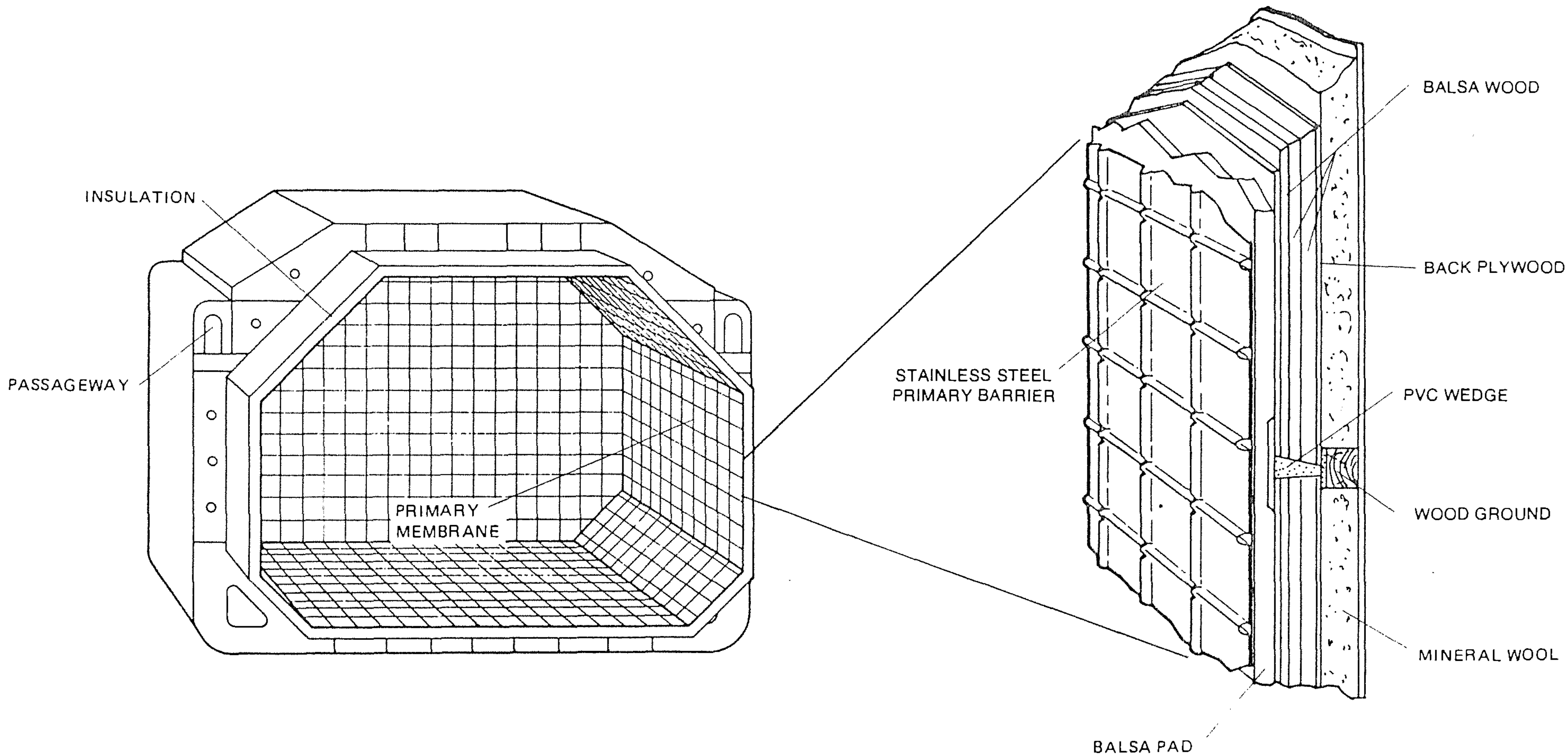
This report does not consider the production, storage, and marine transportation of natural gas liquids and LPGs.

D. Project Marine Transportation Requirements

An optimized configuration of fleet, plant, and terminal capacities for any project generally results after completing a rigorous analysis of all reasonable alternative design combinations. Likewise, the Trans Alaska Gas System project will require a rather comprehensive engineering effort before a viable overall plan is submitted for final approval.



GAZ TRANSPORT MEMBRANE TANK DESIGN
FIGURE 6



TECHNIGAS MEMBRANE TANK DESIGN
FIGURE 7

The present study, however, employs existing technology and the use of the existing supply of LNG vessels with cargo capacities in the range of 120,000 - 130,000 m^3 and having an average cargo capacity of 126,000 m^3. Further, the assumed fleet has been sized to have sufficient capacity to lift and transport approximately 104% of the annual quantity of LNG produced at the Nikishka plant. This nominal fleet overcapacity is available to accommodate the various design and operational uncertainties related to project.

If, for example, all of the LNG produced is Nikishka were shipped to Japan, the fleet requirements would range from 6 to 17 vessels.

E. LNG Vessels - Design and Availability

The state of the art for marine transportation of LNG has advanced considerably in the past 15 years. Ships with a design capacity of 125,000 to 130,000 cubic meters are now in operation and designs have been considered for ships with cargo capacities in excess of 180,000 cubic meters. A general arrangement for a typical 125,000 m^3 LNG carrier is shown in Figure 3.

1. Cargo Containment System Design

There are two basic types of LNG containment system designs employed in LNG transportation: the self-supporting and membrane types. The self-supporting design employs cargo tanks which are either spherical or prismatic, constructed with the tank walls capable of supporting themselves and the weight of the LNG cargo. The cargo containment systems of the membrane designs are constructed from thin-walled, metal alloy membranes with the load of the cargo tanks and its LNG cargo supported by the tank insulations and ship structure.

There are at least seven different self-supporting systems and five membrane systems currently in use or offered for license. The self-supporting systems include Conch Methane (Figure 4) Gaz Transport, Esso International, Kverner-Moss (Figure 5), A. G. Weser, and Zellentank.

The membrane systems include Gaz Transport (Figure 6), Gazocean-Technigas (Figure 7), Conch Ocean, McMullen, and Bridgestone.

Although no one design has established a position as the outstanding favorite, the Japanese LNG importers have expressed a preference for the Kverner-Moss design. Alternately, most of the vessels operated by the Algerians are constructed with the Gaz Transport design. There are also several vessels with the Technigas design that have operated successfully for several years.

Historically, the first LNG tanker, "Methane Pioneer", used the Conch system, as did the "Methane Princess" and "Methane Progress". These ships have been sailing between Algeria and the United Kingdom since 1964.

The Gaz Transport or Wormes design is a double-wall containment system using thin sheets of Invar (36% nickel steel). This is the design used in: 1) the two ships which are trading between Alaska and Tokyo, 2) one of the ships trading between Skikda, Algeria and southern France, and 3) the three El Paso vessels built by the France-Dunkerque shipyard which traded between Algeria and the U.S.

The other membrane design used in commercial operation is the Technigas or Gazocean design (Figure 7) which uses the waffle membrane to accommodate thermal expansion and contractions. This design has been used in the "Descartes", the "Mostefa Ben Boulaid", and the "Ben Franklin". Also, this system is in the three El Paso vessels, built at the Newport News shipyard, which also traded between Algeria and the U.S.

2. LNG Vessel Availability

As a result of the slowdown in worldwide LNG activity, the number of laid-up LNG vessels has risen over the last two years and the ensuing disequilibrium between supply and demand for the LNG vessels remains unchecked. As the following data indicates, slightly greater percentage of the larger and more recently constructed vessels are idle in comparison to those built during the early years of the LNG industry development.

VESSELS OPERATING OR LAID UP AUGUST 31, 1982

Ship Size (1,000 M^3)

	20-35	40-50	70-75	87.6	120-130	TOTAL
Operating	4	4	9	2	16	35
Laid Up	3	3	0	0	17	23
TOTAL	7	7	9	2	33	58

The 17 vessels of 120-130,000 M^3 capacity that are presently laid up include the six vessels that were dedicted to the Algerian-El Paso project but excludes the five ships now operating in the Algerian-Trunkline LNG trade. The data does not include the three vessels built by Avondale Shipyards for El Paso which have been removed from consideration for LNG service.

Table 5 profiles the current situation regarding the world wide fleet of LNG vessels. It should be noted that the only vessels presently idled pending resolution of the Algerian price dispute are the six (6) El Paso vessels (Numbers 14-19 Table 5, page 4).

Other LNG vessels that have yet to be delivered or that are on order (Table 5, page 3) include seven vessels of 130,000 M^3 for the Indonesian-Japanese trade and one ship due to be delivered later this year for the Sarawak project. All of these vessels are expected to be placed under a long-term charter for projects that are encountering no difficulty in development and, as such may be laid up for only short periods of time.

3. El Paso LNG Vessels

Subsidiaries of the El Paso Company entered into long term contracts in 1969 and the early 1970s for the purchase and sale of Algerian LNG to the U.S. These contracts contemplated the construction and the operation of 9-125,000 cubic meter LNG vessels. These vessels were to be owned by subsidiaries of the El Paso Company, and were to be used to deliver LNG to Cove Point, Maryland and Elba Island, Georgia.

Six of the nine vessels were constructed and placed into the project's service. Construction of three of the vessels (those built by Avondale Shipyards) was never completed, and these vessels are no longer considered fit for LNG service. Three of the six El Paso vessels that actually operated were constructed by Newport News Shipbuilding and Dry Dock Company, were registered in Wilmington, Delaware under the U.S. flag and financed under MarAd Title XI guarantees. These three vessels are:

	Delivered	Entry Into Service	Status
El Paso SOUTHERN	05/31/78	10/18/78	Lay-Up (US)
El Paso ARZEW	12/08/78	01/15/79	Lay-up (US)
El Paso HOWARD BOYD	06/29/79	07/17/79	Lay-up (US)

The other three El Paso vessels were constructed by Ch. de France-Dunkerque, were registered in Monrovia, Liberia under the Liberian flag and financed through two French banks under typical OCED terms. These three vessels are:

	Delivered	Entry Into Service	Status
El Paso PAUL KAYSER	05/25/75	09/15/78	Lay-Up (US)
El Paso SONATRACH	10/12/76	03/01/78	Lay-up (Norway)
El Paso CONSOLIDATED	06/08/77	05/29/78	Lay-up (US)

It may be possible that the three NNS vessels could qualify for trades between two US ports. However, the three FD vessels could qualify only by receiving a special Jones Act waiver.

Currently, these six vessels are for sale by El Paso. Long term charter arrangements may be possible with El Paso as well.

F. LNG Safety

Design requirements for gas ships, as codified by the U.S. Coast Guard and IMCO, are far stricter than those for oil tankers. For instance, typical gas carrying vessels are constructed with double bottoms and double hulls to minimize the impact on cargo banks in the event of collision, grounding or stranding. Cargo tanks must be located at specified minimum distances inboard from the ship's outer hulls.

The cargo tanks are never opened when transfering cargo. During LNG vessel loading and discharge operations, the LNG vapor is either taken from the ship or returned to the ship from the LNG storage tanks on shore to replace the volume of liquid that is discharged to maintain a closed system at all times. These built-in safeguards are instrumental in preventing serious consequences of accidents to LNG vessels.

G. Economics

The cost of shipping LNG is a function of the capital investment in the LNG vessels and shorebased facilities plus the related annual operating expenses. The capital charge (depreciation, interest expense, profit, and taxes on income) component of a freight rate will depend on the capital costs of both the LNG vessel and the required shorebased facilities; the specific financing arrangements (capitalization, debt term and interest rate), the rate of return desired by the project participants and the income tax laws which apply to the owners of the ships and the owners of the shorebased facilities.

The annual operating expenses for the LNG vessels will vary with the complement and nationality of the ships' crews, the trade route (as it affects vessel insurances) and the cost of marine fuel oil. These three items can easily comprise over 65% of an LNG vessel's annual operating expenses.

Annual operating expenses for the shorebased facilities will depend on the type of facilities needed to support the LNG fleet and the personnel and overhead required to maintain efficient operations.

1. Capital costs and Freight Rates - Vessels

   As stated (Table 5), approximately seventeen LNG vessels, ranging in size from 120,000 to 130,000 cubic meters, are currently in a laid-up status and, hence available to the project. A definitive statement regarding whether these vessels are available for purchase or whether their owners would prefer to charter them into the project on a long-term basis is beyond the scope of this report. Suffice it to say, however, that the cost to the project would be considerably less if any one of the available vessels were to be obtained for the project as opposed to acquiring a newly-constructed vessel of the same capacity.

   a. The El Paso LNG Vessels

      The average cost to purchase the three El Paso vessels which were constructed by Newport News Shipbuilding and Dry Dock Company is estimated to be $57.6 million each or $172.8 million for all three. With annual operating expenses estimated at $13.7 million and capital charges estimated at $11.5, the cost of transporting LNG in one of these vessels would be as follows:

Unloading Terminal	Approximate Freight Rates in U. S. Cents Per Million BTU Delivered
Osaka, Japan	58.1
Inchon, South Korea	67.9
Ft. Conception, California	38.3
Bellingham, Washington	31.3

If the three vessels constructed by Chantiers de France Dunkerque (CFD) for El Paso were purchased for the project for a total estimated cost of $35 million, then, given the same return to capital and similar operating expenses as shown for the NNS vessels, the approximate cost of transport LNG in one of the CFD vessels would be as follows:

Unloading Terminal	Approximate Freight Rates in U. S. Cents Per Million BTU Delivered
Osaka, Japan	37.1
Inchon, South Korea	43.4
Ft. Conception, California	24.5
Bellingham, Washington	20.0

b. New Vessels

The cost of newly-constructed LNG vessels can vary greatly depending primarily on the country of construction and the health of the world-wide ship building industry. Currently, the cost would probably fall within the range of $150-200 million. LNG vessels costing in this range and having the same return to capital and operating expenses as the El Paso ships would require freight rates as follows:

Unloading Terminal	Approximate Freight Rates in U. S. Cents Per Million BTU Delivered
Osaka, Japan	100.7 - 123.7
Inchon, South Korea	117.8 - 144.7
Ft. Conception, California	66.4 - 81.6
Bellingham, Washington	54.3 - 66.7

As reflected in Section D, Phase III deliveries would require a maximum of 19 ships if all the LNG were delivered to Inchon, Korea, and a minimum of 9 if all deliveries were made to Bellingham, Washington. If it is assumed that 50 percent of the LNG would be delivered to the west coast of the United States and the remainder to Japan and Korea, the project would require approximately 14 ships. Further, assuming that all six of the El Paso vessels were brought into the project and newly-constructed LNG vessels made up the difference, the approximate, average freight rates which would be required are as follows:

Delivery Area	Approximate Average Freight Rates in U.S. Cents Per Million BTU Delivered
Far East	84.4 - 98.7
U.S. West Coast	46.7 - 54.6

c. Use of Chartered Ships

An alternative to purchasing newly-constructed LNG vessels is obtaining existing ships through a chartering arrangement. Most charter agreements are based on a rate, expressed in dollars per cubic meter of LNG loaded, plus the actual costs for certain operating expenses, such as port charges and marine fuel. Variations in the rate and the operating expense items handed separately result from negotiations between the parties to the agreement.

It is reasonable to assume that the bottom line delivered cost for an LNG vessel chartered today would be about $15 per cubic meter loaded (including all capital charges and operating expenses) which would equate to a delivered rate per million BTU of about 66.4¢ to the Far East and 65.8¢ to the U.S. west coast. In short, the use of chartered ships which are currently in a laid-up status would tend to lower the average freight rates shown for deliveries to the Far East, but increase them slightly for deliveries to the U.S. west coast.

2. Capital Costs and Operating Expenses - Shorebased Facilities

Shorebased facilities are required, separate from the marine terminal, to service the LNG vessel fleet and to administer the ocean shipping segment of the project. The exact requirements cannot be estimated until the LNG vessel fleet size and the delivery points are known. However, it is estimated that the increment to the freight rates necessary to cover the cost of these facilities will not be more than 5¢ per million BTU delivered.

3. Fleet Summary

The overall marine transportation economics is based on three assumed combinations of LNG vessels. The first fleet (Fleet 1) consisted of all newly-constructed ships, the second fleet (Fleet 2) consisted of all chartered ships which are currently in existence, and the third fleet (Fleet 3) consisted of using six El Paso vessels first, with the balance of the fleet requirements made up by chartering currently existing ships. The estimated freight rates, excluding the increment for shorebased facilities, port charges and unloading terminal facilities, for each fleet to deliver all the LNG to each unloading terminal during each phase of the build-up period is shown as follows:

(Stated in U.S. Cents Per Million BTU Delivered)

Destination	Phase I	Phase II	Phase III
Osaka, Japan [1]			
Fleet 1	112.2	112.2	111.4
Fleet 2	65.7	66.2	66.1
Fleet 3	47.6	54.2	58.5

Destination	Phase I	Phase II	Phase III
Inchon, South Korea [1]			
Fleet 1	131.3	123.3	124.8
Fleet 2	65.9	66.3	66.3
Fleet 3	49.5	57.4	60.6
Pt. Conception, California [1]			
Fleet 1	74.0	71.0	71.3
Fleet 2	65.0	65.4	65.4
Fleet 3	27.9	33.5	45.0
Bellingham, Washington [1]			
Fleet 1	55.2	60.5	58.0
Fleet 2	64.7	65.1	65.1
Fleet 3	18.3	25.7	33.8

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[1] Assumes average cost of $175 million per ship

The increment to the freight rates for the fleet shorebased facilities and the port charges at both the loading and unloading terminals would be essentially the same for the three levels of LNG production. These costs, excluding unloading terminal costs, are as follows:

Unloading Terminal	Shorebased Facilities	Port Charges	Total Increment
	Approximate Increment to Each Freight Rate in Cents Per Million BTU Delivered		
Far East	5.0	1.5	6.5
U.S. West Coast	5.0	1.0	6.0

The range for the estimated capital requirements and annual expenses during each phase of the build-up is shown on the following High and Low cases. The Low case represents the costs for the fleet required to deliver 100% of the LNG produced at Nikishka to Bellingham, Washington. Alternately, the high case represents the costs for the fleet required to deliver 100% of the LNG produced at Nikisha to Inchon, Korea. As previously stated, these costs exclude the estimates for the capital requirements and associated operating expenses for the fleet shorebased facilities and annual port charge expense.

ESTIMATED CAPITAL REQUIREMENTS AND ANNUAL EXPENSE

(Stated in Millions of Dollars)

Description	LOW I	LOW II	LOW III	HIGH I	HIGH II	HIGH III
Fleet 1						
Capital Requirements	$525	$1,050	$1,575	$1,225	$2,100	$3,325
Vessel Expenses	41.1	82.2	123.3	95.9	164.4	260.3
Fleet 2						
Charter Expenses	171.1	314.3	491.8	171.1	314.3	491.8
Fleet 3						
Capital Requirements	35.0	207.8	207.8	35.0	207.8	207.8
Annual Expenses:						
Vessel Expenses	41.1	82.2	82.2	82.2	82.2	82.2
Charter Expenses	-	-	131.5	4.7	147.9	325.4
TOTAL Annual Expense	41.1	82.2	213.7	86.9	230.1	407.6

1)Based on average purchase cost of $175 million per vessel.

LNG Carrier Review — January 1, 1982

	OWNER	SHIP	SPEED (KNOTS)	SIZE(m^3)	DESIGN	DELIVERY	SERVICE	BUILDER
IN SERVICE								
1.	Conch Methane Tankers Ltd	Methane Princess	17.25	27,400	Conch	1964	Laid-up	Vickers Armstrong (UK)
2.	Methane Tanker Finance Ltd	Methane Progress	17.25	27,400	Conch	1964	Laid-up	Harland & Wolff (UK)
3.	GAZ Marine	Jules Verne	17.00	25,500	Gaz Transport	1965	Algeria-France	Ateliers et Chantiers de la Seine (France)
4.	Naviera de Productos Licuados SA	Laieta	18.00	40,000	Esso	1970	Libya-Spain	Astilleros y Talleres del Noroeste (Spain)
5.	Prora Trasporti	Esso Brega	18.00	41,000	Esso	1969	Laid-up	Italcantieri (Italy)
6.	Prora Trasporti	Esso Porto Venere	18.00	41,000	Esso	1969	Laid-up	Italcantieri (Italy)
7.	Prora Trasporti	Esso Ligure	18.00	41,000	Esso	1970	Laid-up	Italcantieri (Italy)
8.	Arctic LNG Transportation	Arctic Tokyo	18.25	71,500	Gaz Transport	1969	Alaska-Japan	Kockums Mekanieska Verkstad (Sweden)
9.	Polar LNG Transportation	Polar Alaska	18.25	71,500	Gaz Transport	1969	Alaska-Japan	Kockums Mekanieska Verkstad (Sweden)
10.	Gazocean Armement	Descartes	17.00	50,000	Technigaz	1971	Algeria-France	Chantiers de L'Atlantique (France)
11.	Cie Nationale Algerienne de Navigation	Hassi R'Mel	17.50	40,000	Gaz Transport	1971	Algeria-France	CNIM (France)
12.	Shell International Marine	Gadinia	18.00	75,056	Technigaz	1972	Brunei-Japan	Chantiers de L'Atlantique (France)
13.	Shell International Marine	Gadila	18.00	75,079	Technigaz	1973	Brunei-Japan	Chantiers de L'Atlantique (France)
14.	Methane Carriers Ltd	Norman Lady	19.50	87,500	Moss	1973	Abu Dhabi-Japan	Moss Rosenberg Verft (Norway)
15.	Shell Tankers (UK)	Gari	18.00	75,072	Technigaz	12/73	Brunei-Japan	Chantiers de L'Atlantique (France)
16.	Smedvig Tankrederi	Venator	18.50	29.388	Moss	12/73	Floating Storage Das Island	Moss Rosenberg Verft (Norway)
17.	Messigaz	Tellier	17.50	40,000	Technigaz	1/74	Algeria-France	Chantiers Navals de la Ciotat (France)
18.	Shell Tankers (UK)	Gastrana	18.00	75,041	Technigaz	8/74	Brunei-Japan	Chantiers de L'Atlantique (France)
19.	LNG Carriers Ltd	Pollenger	19.00	87,600	Moss	10/74	Spot	Moss Rosenberg Verft (Norway)
20.	Kvaerner Group	Century (ex Lucian)	19.70	29,000	Moss	12/74	Algeria-Spain	Moss Rosenberg Verft (Norway)
21.	Middelburg Shipping Corp	Isabella (ex Kenai Multina)	20.00	35,000	Gaz Transport	4/75	Algeria-Spain	CNIM (France)
22.	Shell Tankers (UK)	Geomitra	18.00	77,731	Gaz Transport	3/75	Brunei-Japan	CNIM (France)
23.	CNIM (France)	Montana	20.00	35,000	Gaz Transport	4/75	for sale by yard	CNIM (France)
24.	Shell Tankers (UK)	Gouldia	18.00	75,001	Technigaz	6/75	Brunei-Japan	Chantiers Navals de la Ciotat (France)
25.	Gazocean Armement	Ben Franklin	19.00	120,131	Technigaz	6/75	Spot (LPG or LNG)	Chantiers Navals de la Ciotat (France)
26.	El Paso Marine Co	El Paso Paul Kayser	20.00	120,009	Gaz Transport	7/75	Laid-up	Chantiers de France Dunkerque (France)
27.	Shell Tankers (UK)	Genota	18.00	77,679	Gaz Transport	10/75	Brunei-Japan	CNIM (France)
28.	Gotaas-Larsen	Hilli	19.50	126,227	Moss	12/75	Abu Dhabi-Japan	Moss Rosenberg Verft (Norway)
29.	El Paso Marine	El Paso Sonatrach	20.00	126,165	Gaz Transport	9/76	Laid-up	Chantiers de France Dunkerque (France)
30.	Gotaas-Larsen	Gimi	19.50	126,277	Moss	12/76	Abu Dhabi-Japan	Moss Rosenberg Verft (Norway)
31.	Cie Nationale Algerienne de Navigation	Mostefa Ben-Boulaid	19.00	125,000	Technigaz	6/76	Idle Modifications by yard till 3/82	Chantiers Navals de la Ciotat (France)
32.	Zodiac Shipping Co	Gastor	19.3	122,255	Gaz Transport	8/77	Then laid up pending Indonesia-Los Angeles	Chantiers de L'Atlantique (France)

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	OWNER	SHIP	SPEED (KNOTS)	SIZE(m^3)	DESIGN	DELIVERY	SERVICE	BUILDER
IN SERVICE								
33.	Cryogenic Shipping Corp (Gotaas-Larsen)	Golar Freeze	20.00	125,858	Moss	3/77	Abu Dhabi-Japan	Howaldtswerke-Deutsche Werft (Germany)
34.	Gotaas-Larsen	Khannur	19.50	126,360	Moss	7/77	Abu Dhabi-Japan	Moss Rosenberg Verft (Norway)
35.	El Paso Marine Co	El Paso Consolidated	20.00	124,989	Gaz Transport	6/77	Laid-up	Chantiers de France Dunkerque (France)
36.	Cie Nationale Algerienne de Navigation	Larbi Ben M'Hidi	20.00	129,500	Gaz Transport	6/77	Algeria-USA	CNIM (France)
37.	Cryogenics Energy Transport Inc	LNG Aquarius	20.40	125,000	Moss	6/77	Indonesia-Japan	General Dynamics (USA)
38.	Odyssey Trading Co	Nestor	19.30	122,255	Gaz Transport	10/77	Laid-up pending Indonesia-Los Angeles	Chantiers de L'Atlantique (France)
39.	LNG Transport Inc	LNG Aries	20.40	126,312	Moss	12/77	Indonesia-Japan	General Dynamics (USA)
40.	Leif Hoegh	Hoegh Gandria	21.00	125,000	Moss	2/78	Abu Dhabi-Japan	Howaldtswerke Deutache Werft (Germany)
41.	Louis Dreyfus	Edouard L.D.	20.00	129,500	Gaz Transport	12/77	Laid-up	Chantiers de France Dunkerque (France)
42.	El Paso Southern Co	El Paso Southern	20.00	126,898	Technigaz	5/78	Laid-up	Newport News Shipbuilding (USA)
43.	Liquegas Transport	LNG Capricorn	19.00	126,326	Moss	6/78	Indonesia-Japan	General Dynamics
44.	El Paso Arzew Tanker Co	El Paso Arzew	20.00	126,929	Technigaz	11/78	Laid-up	Newport News Shipbuilding (USA)
45.	Cherokee I Shipping Corp	LNG Gemini	20.40	126,340	Moss	9/78	Indonesia-Japan	General Dynamics
46.	Red Methania	Methania	20.00	131,580	Gaz Transport	10/78	Laid-up pending Algeria-Belgium	Boelwerftemse (Belgium)
47.	Cherokee II Shipping Corp	LNG Leo	20.40	126,449	Moss	12/78	Indonesia-Japan	General Dynamics (USA)
48.	Cie Nationale Algerienne	Chihani Bachir	20.00	129,500	Gaz Transport	2/79	Laid-up	CNIM (France)
49.	El Paso Gamma Tanker Co	El Paso Howard Boyd	20.00	126,894	Technigaz	2/79	Laid-up	Newport News Shipbuilding (USA)
50.	Cherokee V Shipping Corp	LNG Libra	20.40	126,443	Moss	4/79	Indonesia-Japan	General Dynamics (USA)
51.	Cherokee III Shipping Corp	LNG Taurus	20.40	126,334	Moss	7/79	Indonesia-Japan	General Dynamics (USA)
52.	Cherokee IV Shipping Corp	LNG Virgo	20.40	126,451	Moss	12/79	Indonesia-Japan from 5/80	General Dynamics (USA)
53.	Lachmar no 1	Lake Charles	20.40	126,529	Moss	4/80	Laid-up	General Dynamics (USA)
54.	Cie Nationale Algerienne de Navigation	Mourad DiDouche	20.00	125,000	Gaz Transport	7/80	Laid-up	Chantiers de L'Atlantique (France)
55.	Lachmar no 2	Louisiana	20.40	126,000	Moss	9/80	Laid-up	General Dynamics (USA)

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	OWNER	SHIP	SPEED (KNOTS)	SIZE(m^3)	DESIGN	DELIVERY	SERVICE	BUILDER
IN SERVICE								
1981								
56.	M.I.S.C.	Tenaga Empat	20.00	130,000	Gaz Transport	3/81	Laid-up for Sarawak-Japan chartered from 7/84	CNIM (France)
57.	Cie Nationale Algerienne	Ramdane Abane	20.00	125,000	Gaz Transport	6/81	Laid-up	Chantiers de L'Atlantique (France)
58.	Navifond	Hull 559	20.60	133,000	Gaz Transport	6/81	with yard	Kockums Mekanieska Verstad (Sweden)
59.	M.I.S.C.	Tenaga Dua	20.00	130,000	Gaz Transport	7/81	Laid-up for Sarawak-Japan chartered from 10/83	Chantiers de France Dunkerque (France)
60.	Gotaas-Larsen	Golar Spirit	21.00	129,013	Moss	10/81	Spot(LPG or LNG)	Kawasaki Heavy Industries (Japan)
61.	M.I.S.C.	Tenaga Lima	20.00	130,000	Gaz Transport	11/81	Laid-up for Sarawak-Japan chartered from 1/86	CNIM (France)
62.	Redereit Malmoil	Hull 564	20.60	133,000	Gaz Transport	1981	with yard	Kockums Mekanieska Verstad (Sweden)
63.	M.I.S.C.	Tenaga Tiga	20.00	130,000	Gaz Transport	12/81	To be laid-up for Sarawak-Japan chartered from 4/85	Chantiers de France Dunkerque (France)
ON ORDER								
1982								
1.	M.I.S.C.	Tenaga Satu	20.00	130,000	Gaz Transport	3/82	Sarawak-Japan chartered from 1/83	Chantiers de France Dunkerque (France)
2.	NYK/Mitsui OSK/K line *	Hull 1334	19.30	125,000	Moss	12/82	Indonesia-Japan (Badak)	Kawasaki Heavy Industries (Japan)
1983								
3.	NYK/Mitsui OSK/K line *	Hull 1870	19.30	125,000	Moss	1/83	Indonesia-Japan (Badak)	Mitsubishi Heavy Industries (Japan)
4.	NYK 40% MOSK 30% K line 15% Japan line 15%	Hull 1889	19.30	125,000	Moss	5/83	Indonesia-Japan (Arun)	Mitsubishi Heavy Industries (Japan)
5.	NYK/Mitsui OSK/K line *	Hull 1230	19.30	125,000	Moss	10/83	Indonesia-Japan (Badak)	Mitsui Shipbuilding (Japan)
6.	NYK 40% MOSK 30% K line 15% Japan line 15%	Hull 1340	19.30	125,000	Moss	10/83	Indonesia-Japan (Arun)	Kawasaki Heavy Industries (Japan)
1984								
7.	K line 40% NYK 30% MOSK 10% Shinwa 10% Yamashita Shinnihon 10%	Hull 1890	19.30	125,000	Moss	6/84	Indonesia-Japan (Arun)	Mitsubishi Heavy Industries (Japan)
8.	MOSK 40% NYK 30% K line 10% Shinwa 10% Yamashita Shinnihon 10%	Hull 1250	19.30	125,000	Moss	10/84	Indonesia-Japan (Arun)	Mitsui Shipbuilding (Japan)

Note:
Nos 2, 3, and 5 agreed average price Yen 27.6 Billion per ship.
Nos 4 and 6 agreed average price Yen 29.92 billion per ship.
Nos 7 and 8 agreed average price Yen 30.5 billion per ship.

* Equal ownership

TABLE 5 - continued

LNG Carriers Available for Employment During 1982 and Onwards

	NAME	CBM	1982	1983	1984	1985	1986
1.	Pollenger	87,600	x	x	x	x	x
2.	Gastor	122,255	x	x	x	x	x To Pacindonesia
3.	Nestor	122,255	x	x	x	x	x To Pacindonesia
4.	Ben Franklin	120,131	x	x	x	x	x
5.	Hoegh Gandria (a)	125,000	o	o	o	o	o
6.	Golar Spirit	129,013	x	x	x	o	o
7.	Tenaga Satu	130,000	o	To Sarawak-Japan			
8.	Tenaga Dua	130,000	o	To Sarawak-Japan 10/83			
9.	Tenaga Tiga	130,000	x	x	x	To Sarawak Japan 4/85	
10.	Tenaga Empat	130,000	x	x	To Sarawak-Japan 7/84		
11.	Tenaga Lima	130,000	x	x	x	x	To Sarawak-Japan 1/86
12.	Kockums 1	133,000	x	x	x	x	x
13.	Kockums 2	133,000	x	x	x	x	x
14.	El Paso Paul Kayser	120,009	x	x	x	x	x
15.	El Paso Sonatrach	126,165	x	x	x	x	x
16.	El Paso Consolidated	124,989	x	x	x	x	x
17.	El Paso Southern (b)	126,898	x	x	x	x	x
18.	El Paso Arzew (b)	126,929	x	x	x	x	x
19.	El Paso Howard Boyd (b)	126,894	x	x	x	x	x
	TOTAL AVAILABLE FOR CHARTER		16-19	16-17	15-16	13-15	12-14

x = Available for employment in year in question
o = Availability presently uncertain

Possibly available if present LNG pricing problems unresolved

1. Mostefa Ben Boulaid
2. Edward L.D.
3. Chihani Bachir
4. Mourad DiDouche
5. Lake Charles
6. Louisiana
7. Ramdane Abane

Notes: a) On firm charter till July 1982 on Abu Dhabi - Japan trade, thereafter four six months option periods. If options not exercised, vessel will be available. Owners in discussion for long-term charter commencing early 1985 for Indonesia-Korea trade if this is concluded successfully.

b) Under U.S. flag and Title XI financing which presently may restrict vessel to trading on a long-term basis to a U.S. port.

Source: Gotaas-Larsen

LEGAL ANALYSIS

I. Introduction

The Alyeska trans-Alaska oil pipeline (TAPS), which supplies a substantial portion of America's energy today, was built only after a Vice President's vote broke a deadlock over enabling legislation in the United States Senate. TAGS, a project with financial and engineering challenges of similar magnitude, again requires government decisions before construction. The importance of government concurrence in this private project can not be underestimated.

The Committee's counsel, the Alaska and Washington, D.C. based firm Birch, Horton, Bittner, Pestinger and Anderson, has researched the subject of whether these decisions may be made by the President alone, or must include the help of a Congress which has already spent considerable time on Alaska natural gas transportation issues. The Committee's direction has been to examine the issue with an eye toward swift government decision-making while taking into account the body of laws, regulations and treaties which represent America's concerns over energy supplies, the environment, foreign trade and investment.

Counsel's findings are presented here in a question and answer format with further summaries on five issues important to any project sponsor's attempts to gain permission to construct the system. Additional information on work supplied by counsel can be obtained from the Governor's Economic Committee on North Slope Natural Gas, Box 1700, Anchorage, Alaska 99510.

II. Questions and Answers on Legal Issues Confronting TAGS.

The answers to these questions provide a concise review of the legal issues associated with the Committee's work and the project's feasibility.

1. Question: What law governs the transportation to market of North Slope natural gas?

Answer: The principal federal statute is the Alaska Natural Gas Transportation Act, as amended in 1981 by the "Waiver Package." Secondarily, the Natural Gas Act of 1938, as amended, the Natural Gas Policy Act, the Export Administration Act, the Defense Production Act, and several lesser statutes have some relevance to this subject. Where not preempted by federal law, the State of Alaska also has some statutory authority. This authority is largely based in the jurisdiction of the Alaska Public Utilities Commission to certify pipelines and related facilities, State authority for the control of air and water quality, State statutes protecting the habitats of fish and game, and those responsible for managing land and water resources, including coastal zone management.

2. Question: What are the principal authorities now held by the Alaskan Northwest Natural Gas Transportation Company (hereinafter Northwest)?

Answer: Pursuant to the Alaska Natural Gas Transportation Act (hereinafter ANGTA), Northwest received a conditional certificate of public convenience and necessity from the Federal Energy Regulatory Commission (hereinafter FERC). Such certificates are necessary prior to constructing and operating facilities for the transportation of natural gas subject to federal jurisdiction (i.e., interstate natural gas). In November, 1980, Northwest received a right-of-way permit from the United States Department of Interior, covering the Alaska segment of the Alaska Natural Gas Transportation System (hereinafter ANGTS).

3. Question: Can Northwest's authority to build a pipeline for the transportation of North Slope natural gas be transferred to another entity desiring to build a similar line over the identical route?

Answer: Yes. Existing law permits a new entity to accept assignment or transfer of Northwest's authority so long as it seeks to construct a pipeline of "the basic nature and general route" as the Northwest system. ANGTA imposes a limited number of ownership requirements on a successor entity, but those requirements are quite modest. There have already been changes in the members of the Northwest consortium and assignments of interests thereto, so the precedent for transferability has already been established.

"person"

4. Question: Can Northwest's authority be shifted to an entity seeking to build an all-Alaska pipeline to tidewater, with gas conditioned on the North Slope?

Answer: Under existing law, no. ANGTA states that federal officers and agencies shall have no authority to include terms and conditions, in permits issued which would compel a change in the basic nature and general route of the approved transportation system. The Northwest overland pipeline is the transportation system approved by the President and Congress. Moreover, ANGTA does not provide a mechanism whereby the President can change his previous decision once it has been approved by Congress, nor can the President add a second approved route, regardless of whether the initial pipeline applicant has abandoned the project. Therefore, neither FERC nor the Interior Department appear to have the right to transfer the certificate of public convenience and necessity or right-of-way permit to an all-Alaska route sponsor.

5. <u>Question</u>: At what time do Northwest's authorities expire?

<u>Answer</u>: Under existing law, there is no mechanism to define "abandonment" of the project, nor is there a method for restructuring the project upon abandonment. While normal natural gas practice imposes a time limitation on the recipient of a certificate of public convenience and necessity to commence a project, that is not the case with the Northwest system. Northwest's certificate has no time limit for commencement.

6. <u>Question</u>: Does ANGTA preclude an alternate North Slope natural gas pipeline project from becoming a reality?

<u>Answer</u>: Not necessarily. Where a statute imposes significant limitations, the best method for circumventing those restrictions is to avoid the jurisdiction of that statute. While ANGTA has a broad jurisdictional base, there are several ways to escape its jurisdiction. ANGTA applies to "Alaska natural gas," which is defined as "natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the continental shelf thereof." By applying solely to natural gas, it immediately excludes natural gas liquids (unless they are commingled with natural gas in an interstate pipeline system), and substances derived from the processing of natural gas, such as methanol.

There appears to be no jurisdiction conferred on FERC by ANGTA or the Natural Gas Act covering a pipeline from Prudhoe to tidewater, if the gas transported through the line is not later delivered to the Lower 48. This would be an <u>intra</u>state pipeline, when ANGTA only applies to <u>inter</u>state pipelines. FERC and other federal agencies have some jurisdiction over exports of the throughput of such a line and, arguably, FERC may have jurisdiction over the terminal facility involved in the export process. If such an intrastate facility was constructed outside the purview of ANGTA, the Department of Interior would not be precluded from issuing a right-of-way permit to its owner.

Another possible approach to avoid the jurisdictional tentacles of ANGTA would be to condition the North Slope gas at tidewater, rather than at Prudhoe Bay, thus characterizing the segment of the project between the wellhead and tidewater as a "pipeline gathering system." As a gathering line, the pipeline would be exempt from FERC certification requirements under the Natural Gas Act and presumably from ANGTA as well.

7. Question: What is a pipeline gathering system?

Answer: The term "gathering system" as used in the natural gas industry refers to collecting gas from wells and bringing it by separate and individual lines to a central point so that it can be delivered into a single line. FERC uses four tests to determine whether a particular system is in fact a "gathering system." Section 717 (b) of the Natural Gas Act excludes facilities for "the production and gathering of natural gas" from its jurisdiction. Thus, production and gathering of natural gas is within the exclusive domain of state regulatory commissions. If the all-Alaska line contemplated were viewed as a "production or gathering line," the project could avoid much federal regulation.

8. Question: How realistic is it to consider a multi-billion dollar, 800 mile project as a gathering system?

Answer: On more than one occasion, FERC has determined that pipeline systems more than 100 miles in length qualify as gathering systems. While the burden of persuasion would be on the applicant seeking to convince FERC that the all-Alaska system is a gathering system, the tests used by the agency in determining whether a particular facility would be exempt under the gathering system exemption give the all-Alaska project a fighting chance of success. The agency determination regarding qualification for the gathering system exemption is always made on a case-by-case basis.

9. Question: Can North Slope natural gas be exported?

Answer: Yes, if certain requirements are met. Unlike North Slope oil, the restrictions on exporting North Slope natural gas are not impossible to meet. The linchpin is Presidential approval. Under ANGTA [15 U.S.C. 719 (j)], export of more than 1,000 Mcf per day of Alaska North Slope natural gas to countries other than Canada or Mexico must receive Presidential approval in order to be permissible, and that approval must be based on a finding that such exports "will not diminish the total quantity or quality, nor increase the total price of energy available to the United States." When this provision was enacted, it probably constituted a nearly insurmountable obstacle. At present, the hurdle may be more illusory than real. Today, the United States is awash in natural gas, and thus it is quite possible that the President could reach and sustain a finding that construction of an Alaska natural gas transportation system would not run afoul of the limitations imposed by this section.

He could determine that the existence of such a transportation system would give the country access to

North Slope gas that is not "available" today, so that exports would not diminish the quantity of energy available in the United States. Nor would the export diminish the quality of energy available, given the overabundance of natural gas. Finally, it would be easy to sustain a finding that export of this gas would not bring about an upward movement of energy prices throughout the United States. We are not predicting that the President will make such a determination, only that an objective review of today's domestic energy picture leads to the conclusion that the section 719 (j) restrictions should not be overestimated. There are other federal statutes that must be satisfied before natural gas, in LNG form, can be exported. These requirements may be found in the Natural Gas Act, the Export Administration Act, the Energy Policy and Conservation Act, and the Natural Gas Policy Act. While these requirements cannot be overlooked, we believe that were the President to make a section 719 (j) finding in favor of North Slope gas exports, the other requirements would fall by the wayside.

10. Question: Are there export controls on substances made from natural gas, such as methanol?

Answer: There are limited controls on any exports from the United States. Mostly, they arise under the Export Administration Act. Generally, we see no serious restrictions on export of methanol made from North Slope natural gas, or other similar gas-originated substances.

11. Question: Are there significant export controls on North Slope natural gas liquids?

Answer: The export controls that would apply to natural gas liquids appear to be quite modest, and again arise primarily out of the Export Administration Act and the Energy Policy and Conservation Act. Natural gas liquids are not regulated under ANGTA or the Natural Gas Act so long as they are not commingled in an interstate gas stream. If the all-Alaska project exports its throughput, then it would not qualify as an interstate pipeline, and the limitations on NGL exports would be minimal.

12. Question: If a small fraction of the gas transported by an all-Alaska system was delivered as LNG to the United States, would that impose greater regulatory requirements on the project?

Answer: Yes. It would materially increase the restrictions on the entire project, regardless of how much of it is devoted to less regulated substances such as NGLs and methanol. When a facility transports some gas interstate, it loses its intrastate exemption and becomes a FERC jurisdictional facility and kicks ANGTA back into operation.

13. Question: Assume an entity sought to build an all-Alaska gas pipeline for delivery of some or all of its throughput to the United States as LNG; what would be the best method for minimizing regulatory and legal problems now facing such a project?

Answer: The fastest, most problem free method of gaining federal approval for such a project would seem to be via amendment of ANGTA or replacement of it by a new, but similar measure. Such legislation could avert drawn-out litigation, motivate federal agencies to act expeditiously and favorably to an all-Alaska project, create the best possible political climate, and inspire confidence in the financial community for such an all-Alaska route. Two pipeline projects have dominated the energy scene in Alaska since 1970: the Trans-Alaska Oil Pipeline System and the Northwest project. Each project required an act of Congress in order to by-pass major hurdles to the project presented by existing federal legislation, administrative regulations, bureaucratic inefficiency, and the threat of long-term litigation. There is every reason to believe that an interstate pipeline successor to Northwest could be benefitted by such legislation, and that Congress may be willing to enact it. We cannot overlook the fact that the North Slope of Alaska contains the Nation's largest proven natural gas reservoir, as well as incalculable potential. The national security benefit of having this domestic hydrocarbon pool available to the country justifies (and already has justified) congressional action. When you add the nationwide economic benefits (employment, industrial production, etc.), as well as possible balance of trade and diplomatic advantages should some exports take place, the ledger tilts very strongly toward the conclusion that a new or modified ANGTA can be extracted from Congress.

14. Question: Are there serious limitations on foreign investment in an all-Alaska gas pipeline project?

Answer: No. There are federal and state statutes regulating foreign investment in domestic energy projects, but these statutes do not effect prohibitions. Generally, they only impose reporting requirements. The legislative history of the Alaska gas pipeline project indicates a willing acceptance by Congress of foreign investment, on both the debt and equity side.

15. Question: How would a decision by private investors and government to reroute an Alaska natural gas transport system affect American agreements with Canada?

Answer: Our relations with Canada over the pipeline are still governed by the Transit Pipeline Treaty, signed in 1977. That treaty, which applies to the ANGTS project, relies on construction being financed through private sources. Neither the Canadian nor the U.S. governments can force private investment in the project.

The Canadians have discovered an extraordinary amount of natural gas in Western Canada and at present have more than 10,000 shut-in natural gas wells in Alberta alone. Canadians are also exploring exports to Japan.

16. Question: What regulatory controls does the State of Alaska have on an all-Alaska pipeline project?

Answer: Where not preempted by ANGTA or other federal law, the State has a good deal of authority over various aspects of the all-Alaska project or a variation of it. The Alaska Public Utilities Commission has jurisdiction over the transportation of LNG exported to foreign markets. Other State agencies would have jurisdiction over other aspects of the project, such as air and water quality, fish and game habitats, and land and water resources. The all-Alaska route system, if not preempted, would have to receive a certificate of public convenience and necessity from the APUC.

III. Summary of Other Research

In addition to the Questions and Answers, a series of legal opinions and supporting original research provided the committee with information on the legal status of a potential all-Alaska natural gas pipeline.

The research submitted by the committee's legal counsel treated a score of issues related to all aspects of the pipeline and dealt in greater depth with some of the areas discussed in the Question and Answer section. The five major areas researched included:

1. To what extent may the current Alaskan Northwest Natural Gas Transportation Company (Northwest) authorities and approvals may be used by an alternative all-Alaska pipeline project?
2. What federal and state regulatory authority would exist over an all-Alaska pipeline that either produced LNG to ship to domestic or foreign markets, or that extracted NGL for shipment to domestic or foreign markets? If the natural gas or NGL options were combined in some percentage mix, would any of the regulatory conclusions be changed?
3. Could an all-Alaska pipeline be considered a gathering system under the Natural Gas Act and thereby avoid FERC certification requirements?
4. What federal and state restrictions exist related to foreign investment in a pipeline project?
5. What federal and state regulatory approvals of all types, including test results and environmental studies, currently in existence with respect to the Northwest project, could be used by an all-Alaska system following all or part of the Northwest route?

The research provided by the committee's legal counsel on each of these five areas has been summarized.

1. <u>TO WHAT EXTENT MAY THE CURRENT ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY (NORTHWEST) AUTHORITIES AND APPROVALS BE USED BY AN ALTERNATIVE ALL-ALASKA PIPELINE PROJECT?</u>

Northwest currently holds two major authorities necessary for construction and operation of an Alaskan gas pipeline — a conditional certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission (FERC) pursuant to the Alaska Natural Gas Transportation Act (ANGTA) and a right-of-way permit granted by the Department of the Interior. A new entity seeking to construct a pipeline of the same basic nature and general route as the Northwest system can have Northwest's authority transferred to it, provided it meets a set of designated ownership requirements. These ownership requirements are quite modest. The Department of the Interior and other agencies that have issued permits to Northwest would appear to have the same ability to approve transfer to a new entity.

If the new entity desires to construct an all-Alaska pipeline to transport Prudhoe Bay gas to Fairbanks and then to tidewater for ultimate delivery in whole or in part to the lower 48, the authorities held by Northwest do not appear transferable and/or modifiable. We so conclude because the Alaska Natural Gas Transportation Act states that federal officers and agencies shall have no authority to include terms and conditions, or to take actions, if said terms and conditions or actions would compel a change in the basic nature and general route of the approved transportation system. The Northwest Alaska overland pipeline is the approved transportation system.

ANGTA does not permit the President to act once Congress has approved the pipeline applicant chosen by him, which it did in 1977. Therefore, under existing law, the President cannot propose an additional Alaska gas pipeline applicant, nor can he change his predecessor's decision and replace Northwest with another applicant.

With regard to the Alaska Natural Gas Transportation System, there is no statutory provision disposing of the issue of project abandonment by virtue of non-performance. Under standard gas pipeline law, certificates of public convenience and necessity generally include time periods for performance after which they lapse. The conditional certificate held by Northwest has no such time period. As a result, we must conclude that the issue of whether Northwest has abandoned the project, and when, if ever, its grant of authority lapses, would have to be litigated. If Northwest took affirmative action pronouncing to the FERC that it permanently abandon the project, the streamlined mechanism under ANGTA is not resurrected for the President to choose an alternate applicant.

Additionally, the option of going through a standard comparative certification proceeding at FERC may or may not exist subsequent to a Northwest abandonment, depending on one's interpretation of ANGTA's duration and preemptive character.

There appears to be no ANGTA or FERC jurisdiction over an intrastate pipeline from Prudhoe Bay to tidewater, if the gas transported through the line is not later delivered to the lower 48. Such a system would not be an interstate gas transmission system. FERC and other federal jurisdiction over the export of the throughput of such a line would exist in the form of export license requirements, etc. Arguably, FERC may have jurisdiction over the terminal facility involved in the export process.

Neither the Alaska Natural Gas Transportation Act nor the Natural Gas Act would appear to give FERC jurisdiction over certification and operation of an intrastate line, if the throughput of that line is converted to a processed commodity that is neither natural gas nor LNG (nor associated gases, such as methanol). Our limited research on this point indicates that such processed end product could be sold in the lower 48 or exported without incurring FERC jurisdiction.

Our conclusions regarding the transferability of Northwest's certificates and permits under the ANGTA derive from a combination of legal analysis and the practicalities of developing a major energy project like an all-Alaska gas pipeline entity. Since there is little case law regarding ANGTA, it is possible that if litigated, more flexibility would be found in the statute by Federal Courts than we have asserted. However, the prospect of protracted litigation on a multitude of technical legal interpretations of ANGTA provisions is tantamount to a prohibition, regardless of the outcome of the litigation, since the endless delay and uncertainty attached thereto would make capital acquisition extremely difficult if not impossible.

The fastest, most problem free method of gaining federal certification, either new or transferred from Northwest, from an all-Alaskan line that would have maximum market and product flexibility is through amendment of ANGTA, or replacement of it by a new, but similar measure. Such legislation would proscribe drawn-out litigation, motivate federal agencies to act expeditiously and favorably, create the best possible political climate, and inspire confidence in the financial community for such an all-Alaska route.

2. FEDERAL AND STATE REGULATORY AUTHORITY OVER GAS SHIPMENTS

A. FEDERAL AUTHORITY OVER SHIPMENT OF LNG TO FOREIGN AND DOMESTIC MARKETS

Many layers of Federal jurisdiction exist over the shipment of LNG to foreign and domestic markets. With regard to export of LNG to foreign markets: under the Natural Gas Act of 1938, and related Executive Orders, the Economic Regulatory Administration (ERA) has jurisdiction to approve the exportation of the gas; the Federal Energy Regulatory Commission (FERC) may have jurisdiction to certify the LNG facilities; the Office of Energy Emergency Operations has jurisdiction to approve export facilities at a United States border; under ANGTA, the President must approve the export of Alaska natural gas in excess of 1,000 Mcf per day to countries other than Mexico and Canada. Under the Energy Policy and Conservation Act of 1975 and the Export Administration and Defense Production Acts, the Department of Energy also has authority to restrict LNG export for national security or energy conservation purposes in times of national emergency or energy shortages. In addition, other federal agencies have jurisdiction over other aspects of an LNG project such as the construction, safety and design of facilities, and the protection and control of the coastal and marine environment.

With regard to shipment of LNG to domestic markets, FERC has jurisdiction to certify the LNG facilities used as part of the interstate transportation of LNG.

B. STATE AUTHORITY OVER SHIPMENT OF LNG TO FOREIGN AND DOMESTIC MARKETS

Certain state agencies would also have authority over various aspects of an LNG project. The Alaska Public Utilities Commission (APUC) could have jurisdiction over the transportation of LNG exported to foreign markets, to the extent this authority is not preempted under the Natural Gas Act. This authority would certainly be preempted if the LNG is shipped to domestic markets, however. Other state agencies would have jurisdiction over other aspects of an LNG project, in order to administer state controls over air and water quality, fish and game habitats and land and water resources.

C. FEDERAL AUTHORITY OVER SHIPMENT OF NATURAL GAS LIQUIDS TO FOREIGN AND DOMESTIC MARKETS

Federal authority exists in fewer areas over the shipment of NGLs to foreign and domestic markets. Concerning export of NGLs to foreign markets, the Department of Energy does not have jurisdiction to approve either the export of the product or the construction and operation of facilities because NGLs are not subject to the Natural Gas Act. Also for this reason, the Department of Energy would not have jurisdiction over interstate shipment of NGLs, as long as the liquids were not commingled with jurisdictional gas. While the definition of natural gas in ANGTA is broad, it almost certainly does not reach NGLs, so we doubt that the President would have to approve exports of NGLs derived from greater than 1,000 Mcf of natural gas. Export of NGLs is regulated under the Energy Policy and Conservation Act, the Export Administration Act and the Defense Production Act. Other federal agencies have authority over the construction, safety and design of facilities and the protection and control of the coastal and marine environments.

D. STATE AUTHORITY OVER SHIPMENT OF NATURAL GAS LIQUIDS TO FOREIGN AND DOMESTIC MARKETS

1) APUC Jurisdiction: No Certification of Natural Gas Liquid Facilities Required

Gas processing plants, treaters and separators are specifically excluded from the definition of pipeline facilities subject to the jurisdiction of the APUC under A.S. 42.06.603(10). Therefore, the APUC does not have jurisdiction to certify any NGLs separation facility in conjunction with certification of an intrastate natural gas transportation system.

2) <u>Other State Authority Over Shipment of Natural Gas Liquids to Foreign or Domestic Markets</u>

In Section II 1. of this memorandum, we discussed the host of other state agencies which would have jurisdiction over a project which produced LNG for export or shipment to the lower 48 states. These state agencies would have the same jurisdiction over the construction and operation of a pipeline project and related marine facilities and transportation for a project which produced NGLs.

E. <u>THE EFFECT OF COMMINGLING NATURAL GAS AND NATURAL GAS LIQUIDS ON FEDERAL JURISDICTION</u>

As discussed above, since NGLs are not considered natural gas under the Natural Gas Act, neither the sale nor the transportation of NGLs is subject to FERC jurisdiction. If the NGLs are transported in a commingled fashion with jurisdictional natural gas destined for shipment to domestic markets, however, certain aspects of FERC jurisdiction would be triggered. According to <u>Cities Service Gas Co. v. United States,</u> 50 F.2d 448 (Ct. Cl., 1974), the FERC would have jurisdiction to control the movement, transportation, measurement, curtailment, quantity, certification and abandonment of the sale of all the gas, but would have no authority over the rates set for the sale of non-jurisdictional gas: NGPA

The FPC has jurisdiction of all gas moving in a pipeline in interstate commerce even if interstate gas and intrastate gas are commingled, and even if the interstate gas is only a small part of the total gas in the pipeline. We find no difficulty with this proposition and agree that it is the law. However, this does not tell the whole story. The jurisdiction vested in the FPC authorized it to control the movement and transportation, measurement, curtailment, quantity, certification and abandonment of sale of gas moving in interstate commerce or in an interstate pipeline, but the FPC has no authority or jurisdiction to fix the rates of all gas sold in interstate commerce.

Therefore, FERC jurisdiction would be increased over NGLs, if the liquids are commingled with jurisdictional natural gas.

3. CAN AN ALL-ALASKA GASLINE BE TREATED AS A PIPELINE GATHERING SYSTEM THEREBY PARTIALLY AVOIDING FEDERAL REGULATORY JURISDICTION?

A. Overview

The premise of treating an all-Alaskan gasline as a gathering system for North Slope gas with a terminal at tidewater has been raised on a number of occasions. The assumption is that an all-Alaskan line could be designed as a gathering system as a means of exempting the line from federal regulatory jurisdiction. Section 1 (b) of the Natural Gas Act [15 U.S.C. S 717 (b)] exempts from regulation (under the Natural Gas Act) transportation or sale of natural gas, the local distribution of natural gas, the facilities used for such distribution or the "production or gathering of natural gas".

As noted, a natural gas company is engaged in the transportation of gas in interstate commerce if it transports gas "between any point in a state and any point outside thereof . . . but only insofar as such commerce takes place within the United States" 15 U.S.C. 717(a). It has been held that transportation of gas by a pipeline located wholly within Texas to an industrial consumer who in turn transports gas into Mexico was not transportation or sale of natural gas in interstate commerce. Border Pipeline Co. v. Federal Power Commission, 717 F.2d 149 (App. D.C. 1948). Thus, any project which would export exclusively for foreign sales, natural gas from the North Slope or gas products derived therefrom, may automatically be exempted from the purview of the Natural Gas Act insofar as pipeline regulation and pricing is concerned. Such an entity would, however, still be subject to FERC approval pursuant to 15 U.S.C. 717(b) insofar as exports of natural gas are concerned.

Assuming, however, that the ultimate market for natural gas includes domestic markets, the Natural Gas Act does not apply to "the production and gathering of natural gas." 15 U.S.C. 717(b). Thus, production and gathering of natural gas is within the exclusive domain of state regulatory commissions. If the all-Alaskan line contemplated were viewed as a "production or gathering line" the project could avoid much federal regulation including the FERC ratemaking authority.

It has been consistently held that "production" and "gathering" are terms narrowly confined to the physical acts of drawing the gas from the earth and preparing it for the first stages of distribution. Northern Natural Gas Co. v. State Corporation Commission of Kansas, 372 U.S. 84, 90 (1963).

See also Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954); Continental Oil Co. v. FPC, 226 F. 2d 202 (C.A. 5th (1955); J.M. Huber Corp. v. FPC, 236 F. 2d 550 (C.A. 3, 1956) cert. den. 352 U.S.C. 971 (1956).

One thing can be counted on: any review of an attempt to exempt an all-Alaskan project from regulation under the Natural Gas Act (except for export requirements) is likely to be reviewed in light of four principles of construction which have been consistently applied to the Natural Gas Act as a whole.

First, the Act was intended to protect the consumer from the economic power of natural gas companies and thus must be construed, whenever possible, as consistent with that purpose. See Panhandle Eastern Pipeline Co. v. Federal Power Commission, 324 U.S. 635 (1945); Interstate Natural Gas Co. v. Federal Power Commission, 331 U.S. 682 (1947); Phillips Petroleum Co. v. Wisconsin, 347 U.S. 62 (1954); United States Gas Improvement Co. v. Continental Oil Co, 381 U.S. 392 (1965); J.M. Huber Corp. v. Federal Power Commission, supra; Saturn Oil and Gas Co. v. Federal Power Commission, 250 F.2d 61 (1957); Re Colombian Fuel Corporation, 15 PUR 3rd 1975 (FPC, 1940).

Second, the Act is almost always liberally construed to carry out the congressional intent behind it: to fill in with a federal presence the regulatory gap caused by pre-1938 judicial decisions which prevented states from regulating interstate flow of natural gas. See Interstate Natural Gas Co. v. FPC, supra; and Federal Power Commission v. Panhandle Eastern Pipeline Co., supra.

Third, the burden of persuasion that a pipeline or facility comes within the exceptions to the Act is to be carried by the proponent and is a heavy burden to bear. See Interstate Natural Gas Co. v. FPC, supra; Phillips Petroleum Co. v. Wisconsin, supra; J.M. Huber Corp. v. Federal Power Commission, supra; Saturn Oil and Gas Co. v. Federal Power Commission, supra; Re Arco Oil Corp., 15 FPC 601 (FPC, 1956).

Finally, it is clear that the actual function of the facility will be the determinative factor as to whether the exclusion in Section 1(b) of the Natural Gas Act applies. Descriptive terminology used within the industry cannot override the actual function of the facilities being examined. J.M. Huber Corp. v. Federal Power Commission, supra; Continental Oil Co. v. Federal Power Commission, 266 F 2d 208 (C.A. 5, 1959); Ben Bolt Gathering Co. v. Federal Power Commission, 323 F 2d 610 (C.A. 5, 1963); Re Northern Natural Gas Co., supra; Re Barnes Transportation Co., 20 P.U.R. 3rd 247 (FPC, 1957); and Re Marathon Oil Co., 10 P.U.R. 4th 198 (FPC, 1975).

There are three tests which have been used by the FERC, and the FERC's predecessor, the FPC, in determining whether a particular facility would be exempted pursuant to 1(b) of the Natural Gas Act.

The first test is known as the "central point test." Under this view of the exclusion, if particular facilities actually function as gathering lines in that they collect gas from various wells, bring the gas through several individual lines to a "central point" and deliver the gas into a single line, all facilities up to the single line are considered gathering facilities. Re Barnes Transportation Co., Inc. 18 F.P.C. 369 (1957).

Under the "central point test," gathering ends when the gas collected ends up in one line. The application of this test appears to be limited to pipeline systems which do not include a processing plant. See Buckeye-Tennessee Gas Gathering Co. Declaratory Order Disclaiming Jurisdiction, Docket No. CP80-386 (Aug. 28, 1980). As such, the test would seem inapplicable to an all-Alaskan pipeline system because of the need for a facility to clean the gas at tidewater.

The second test used to distinguish between transportation and gathering is the "behind-the-plant test" (sometimes referred to as the "pipeline quality test"). Under this test, jurisdiction pursuant to the Natural Gas Act commences when gas of pipeline quality leaves the tailgate of the processing plant. Any facilities located upstream from the gas processing plant are gathering facilities. See Superior Oil Co., Order Disclaiming Jurisdiction, Docket No. CP80-495 (Dec. 15, 1980); Northern Natural Gas Pipeline Co., Opinion No. 538, FPC 362 (1968). This test may be applicable to an all-Alaska project. In general, FERC has applied the test to facilities owned and operated by the seller of the gas in question. When third parties operate the facilities, the FERC has found the facilities to come within its jurisdiction. See Texas Sea Rim Pipeline, Inc., Declaratory Order Docket No. CP79-117, pp 3-4 (Feb. 16, 1979). But, See Philadelphia Oil Co., Order Affirming Initial Decision, Docket No. C175-52 (Jan. 18, 1977) which indicates that no matter who transports, the function of gathering is what the FERC will focus in on.

The third test is known as the "primary function test." It asks what the primary use of the facilities will be. All facts are considered in view of the entire transmission facility. See Ben Bolt Gathering Co., 26 FPC 825 (1961) Aff'd 323 F. 2d 610 (5th Cir. 1963); Marathon Oil Co., Opinion No. 735, 53 FPC 2164 (1975). Here again, an all-Alaska system carrying CO_2 laden gas to tidewater where it would be cleaned might be considered part of a sophisticated gathering system necessitated by the unique transportation barriers imposed by the Alaskan environment and patterns of land ownership.

As noted, decisions as to whether the 1(b) exemption applies are made on a case by case basis. The burden of proof would be on the all-Alaska project. While skeptics may quote otherwise, an all-Alaska line carrying CO_2 laden natural gas to a tidewater processing plant may qualify.

But FERC always has the ability to step in and exert jurisdiction to "fill the regulatory gap." No unfair advantage can result from a FERC decision not to regulate rates charged for the gathering. See Buckeye-Tennessee Gas Gathering Co., Declaratory Order Disclaiming Jurisdiction, Docket No. CP80-386 (Aug. 28, 1980); Carnegie Natural Gas Co., Order Disclaiming Jurisdiction, Docket No. CP77-535 p. 2 (Sept. 29, 1978).

Thus the answer as to whether an all-Alaska system would be considered to be a gathering or transportation system for purposes of distinguishing FERC jurisdiction under the Natural Gas Act is dependent on the application of the above test to the facts. The presence of significant amounts of carbon dioxide in the gas to be transported to tidewater might be enough in and of itself to exempt the facility from FERC jurisdiction. As with most things Alaskan, any decision rendered with regard to the question will be made on the basis of this case alone.

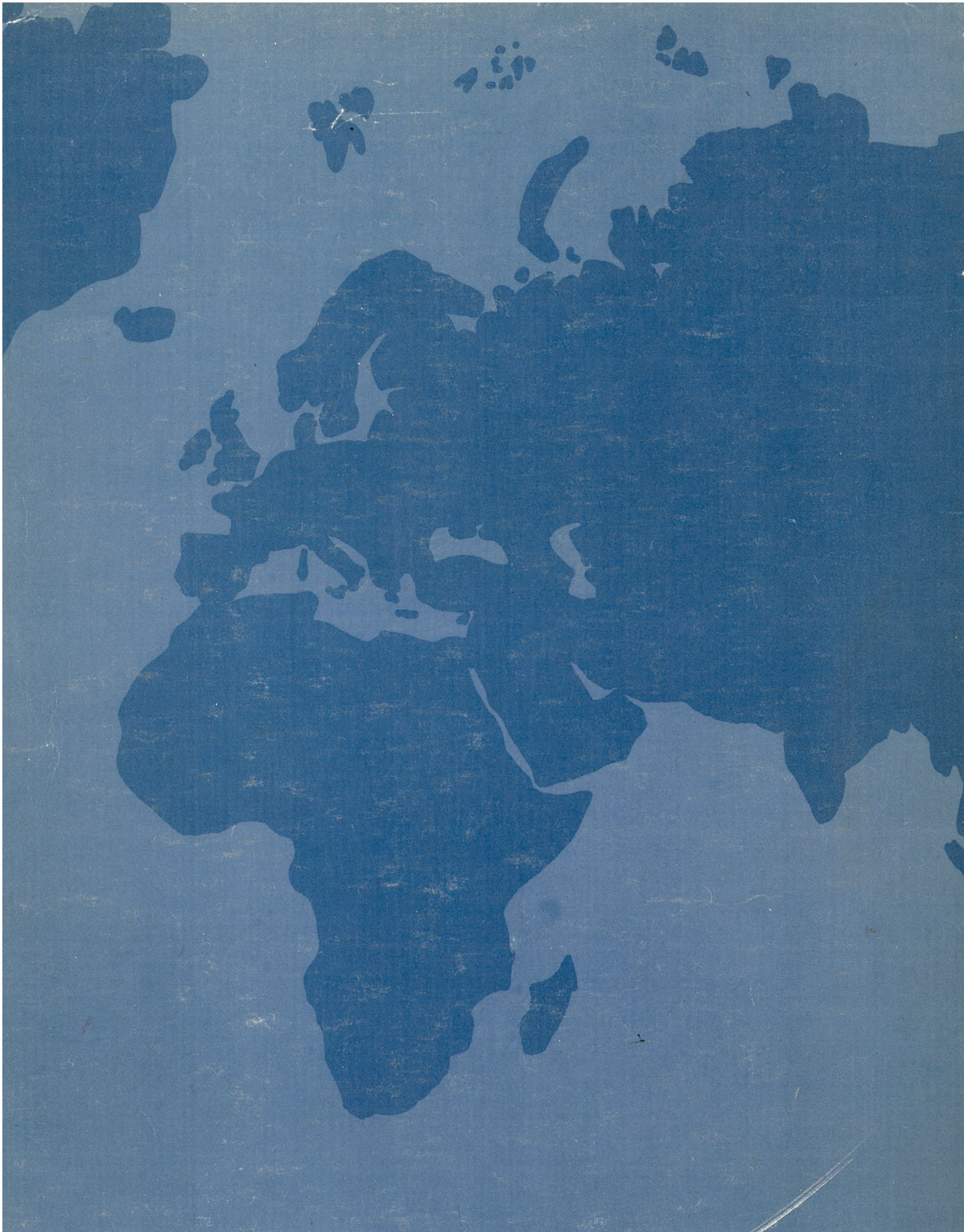
Finally, any line crossing federal lands which is not subject to the Natural Gas Act and which is not serving as a public utility regulated by the state must act as a common carrier. 30 U.S.C. 185 (r). Likewise, a similar provision in the State's Right-Of-Way Leasing Act provides that if the line is not regulated by the federal government pursuant to the Natural Gas Act and does not serve as a state regulated public utility, then it must act as a common carrier, A.S. 38.35.120(1). Thus, it appears that by avoiding regulation under the federal Natural Gas Act of 1938, the pipeline may have to become a common carrier and must accept all gas tendered to it equally. It does not necessarily mean the line is subject to FERC regulation, however.

4. REGULATION OF FOREIGN INVESTMENT IN AN ALL-ALASKA GAS PROJECT

Foreign investment in the United States has existed from the earliest federation days. With certain exceptions, most notably pertaining to national security and defense, such investments have been encouraged and welcomed. Constitutional limitations exist which affect both federal and state regulation of foreign investment. Further, the United States has concluded many commercial treaties and other agreements which have the full force and effect of federal law, thus further impacting federal and state efforts to regulate foreign investment.

5. EXISTING NORTHWEST REGULATORY APPROVALS AND TEST STUDIES WHICH COULD BE USED BY AN ALL-ALASKA ROUTE ENTITY

Northwest has received many regulatory approvals and has conducted many test studies during the planning and pre-operation state of the pipeline. While an all-Alaska route entity would have to apply for its own permits for specific activities, much of the information which has been analyzed and collected by Northwest could conceivably be used as supporting information. Northwest has filed the bulk of this information on a confidential basis. No one has challenged that status under the state's freedom of information statute, but no challenge would be necessary on the part of a TAGS sponsor if an amicable agreement were worked out with Northwest.



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