An overview of natural gas and gasline issues

by

Kay Brown

AN OVERVIEW OF NATURAL GAS AND GASLINE ISSUES

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CHAPTER

I. INTRODUCTION

Throughout this year and next the legislature and several agencies within the executive will be confronted by two major issues relating to the proposed Northwest Gas Pipeline.

(1) What should the State do with its royalty share of Prudhoe Bay gas?

(2) What role should the State play in financing the proposed pipeline?

Not only might these decisions affect billions of dollars of State money, but the underlying facts, principles, and relationships are extremely complex--and to a large extent unknown. As a result, the spectre of dealing with these issues becomes downright formidable.

This paper is an attempt to lay out these facts, principles, and relationships in a comprehensible fashion. It attempts to touch on the full range of gasline considerations and to unravel these inter-relationships. It also is designed to supply the technical tools by which each issue can be approached.

A grasp of the engineering and economic principles is essential; but once this is surmounted, the policy considerations can and must be explored.

Note: This report was updated and revised on June 2, 1978. For that reason, references made to the "Overview" memorandum in the Bache Halsey Stuart Shields consultant report ("Analysis of Proposed Financial Support for Northwest Alaskan Natural Gas Pipeline Project," May 24, 1978) do not correspond to page numbers in this document.

II. WHO IS INVOLVED?

The principal actors in the gasline debate are:

- Gas producers and owners
- Gas purchasers
- Gas transportation (pipeline) companies
- Investors
- Government regulators
- Landowners

GAS PRODUCERS AND OWNERS

A. Gas Producers

The Prudhoe Bay producers are those companies which hold State leases for oil and gas resources on the North Slope. Since geologic conditions mean individual producers draw oil and gas from a common pool (Sadlerochit), allocation of produced oil and gas was negotiated and set forth in a Unit Agreement. Practically all of the oil and gas production is allocated to three companies: SOHIO, EXXON and ARCO.

OIL & GAS PRODUCERS

Company	%Gas Cap Gas[1]	%Solution Gas[2]	%Total Gas[3]	%Total Oil
SOHIO	15%	53%	27%	53%
ARCO	42%	20%	36%	20%
EXXON	42%	20%	36%	20%

1/ Gas cap gas is produced from the gas layer which rests on top of the oil zone. This gas is produced only when a decision is made to withdraw gas from the gas cap. Such a decision would only be made when the gas is intended for sale.

2/ Solution gas is the gas dissolved in the oil which is necessarily produced with the oil. Until sale arrangements are made for this gas, it must be reinjected, flared or used as fuel for field operations.

3/ Total gas production is based on DNR estimates of producible gas cap gas of 19.5 trillion cubic feet and producible solution gas of 8.0 trillion cubic feet (gas cap=70%; solution= 30%), and represents the weighted average of each company's respective allocation of gas cap gas and solution gas.

B. Gas Owners

The producers are all owners of North Slope gas. While not a producer, the State of Alaska is also a gas owner by virtue of a clause in the lease agreements which entitles the State to a 12 1/2% royalty share. Hence, the real ownership of Prudhoe Unit gas is as follows:

GAS & CRUDE OWNERS

Owner	%of Gas Cap and Solution Gas	%Oil
SOHIO	23.5%	46.5%
EXXON	31.5%	17.5%
ARCO	31.5%	17.5%
STATE OF ALASKA	12.5%	12.5%

GAS PURCHASERS

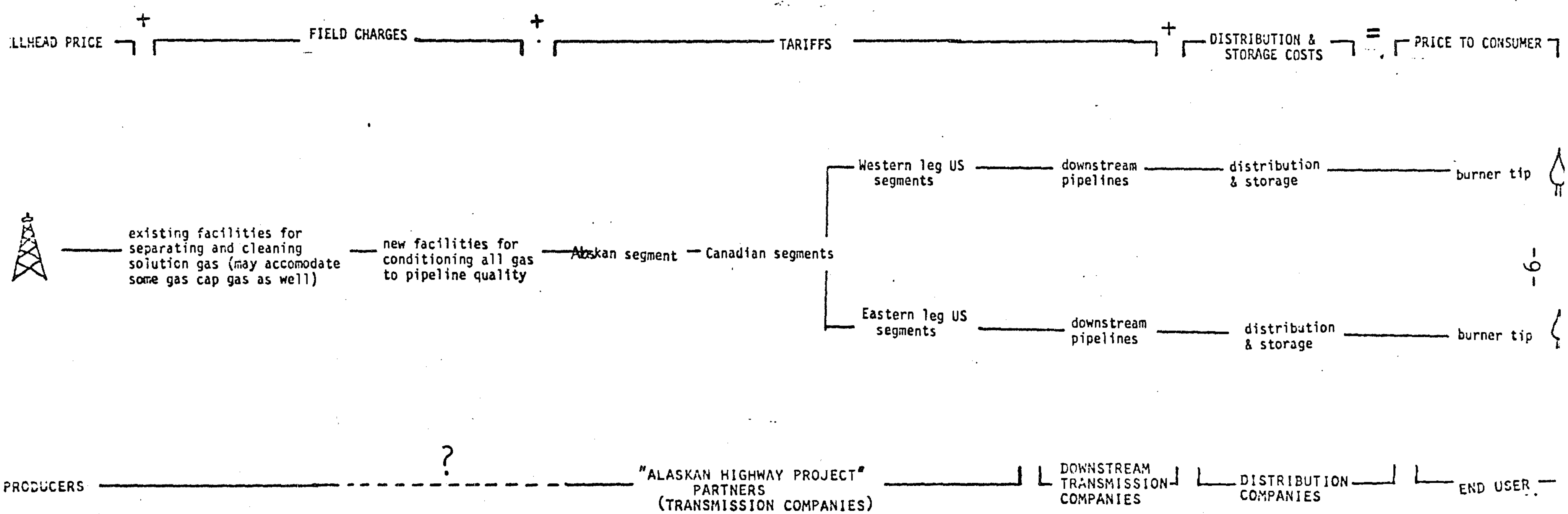
A. Potential Purchasers

The marketing of Prudhoe Bay gas is very different from that of oil. To a large extent the Prudhoe producers are both buyers and sellers of North Slope oil. For example, Exxon is an "integrated" oil company, and it is, therefore, in Exxon's interest for its production arm to "sell" oil to its refining subsidiaries. On the other hand, the major oil companies have never been involved in gas transportation and marketing beyond the field. Gas was historically a nuisance by-product of oil production destined for flaring.

The purchasers of North Slope gas, instead, will be gas distribution companies and interstate gas transmission (pipeline) companies with established fuels markets. End consumers purchase gas from these companies for commercial and residential heating, power generation by electric utilities, and industrial use as boiler fuel, process gas and petrochemical feedstocks. (See attached chart.)

TRACKING THE FLOW OF GAS FROM THE WELLHEAD

TO THE CONSUMER BURNER TIP



Customers who use the gas for heating and power are primarily interested in "dry gas" (composed of methane, which is abbreviated C^1). This is the type of gas produced in Cook Inlet and used in Anchorage households. However, North Slope gas is "associated" with an oil reservoir and therefore also contains heavier hydrocarbons (C^2, C^3, C^4 - ethane, propane, butane) which can be burned as fuel but have alternative uses as petrochemical feedstocks for the production of plastics and other man-made materials. As such, these gas "liquids" may attract purchasers from the petrochemical industry, either those interested in locating a new facility in Alaska, or those with existing plants elsewhere along the pipeline route.[1] Dry gas and gas liquids can either be sold separately to different purchasers or in combination to a single purchaser.

The State might also play the role of a gas purchaser if it chooses to negotiate a trade with the producers. A portion of its royalty share of dry gas could be offered for sale to enable purchase of producer liquids, if this would provide a more attractive volume and type of resource for encouraging petrochemical development in Alaska.

1/ Fertilizer companies and fuels companies may also be interested in the methane for production of ammonia/urea or methanol.

POTENTIAL PURCHASERS

Interstate Gas Transmission Companies

Gas Distribution Companies

Petrochemical, Fertilizer and Methanol Companies

State of Alaska

B. Conditions Affecting Sales to Purchasers

Which, if any, of the above potential purchasers will eventually sign gas purchase contracts depends, in part, upon economic considerations. The considerations include what price gas owners view as acceptable, and how much the purchaser is willing to pay (taking into consideration other gas sources or alternative fuels). In addition, if demand surpasses available reserves, competition may weed out certain types of purchasers.

However, sales will also be affected by State and federal intervention. On the State side, the State as royalty owner may grant a sale preference to a particular purchaser, such as a petrochemical company or Alaskan gas distribution company, so as to meet goals other than strict monetary return.

On the federal side, FERC retains powers over those gas sales. While FERC's jurisdiction is technically complex[1], the

1/ FERC has approval authority over "sales for resale in interstate commerce," and it authorizes the use of pipeline capacity over any sale, regardless of whether it possesses direct sale approval powers.

end effect is that FERC can assert power through some mechanism over virtually any sale of gas which uses an interstate line. FERC can exercise this power freely to accomplish any defensible public purpose.

In addition to FERC's normal powers, the President's Decision, as approved by Congress, clearly charges the Secretary of Energy to use his or her approval authority to ensure equitable distribution to all parts of the country. If producer/purchaser negotiated sales result in a West Coast/East Coast market ratio vastly different from 30%/70%, FERC is empowered to require adjustments in sales.

CONDITIONS AFFECTING SALES TO PURCHASERS:

Economic/Marketing

State Policy for sale of its royalty gas

Federal regulation:

FERC authority to approve sales
DOE authority to approve East/West distribution of sales

TRANSPORTATION COMPANIES (Pipelines)

This whole gasline question came to the fore because three competing consortiums of interstate transmission and distribution companies (originally, Arctic, El Paso and Alcan) approached FERC for approvals to construct a pipeline to transport gas from Prudhoe Bay to the Lower 48.

A. Gas Purchasers' Involvement in Pipeline Ownership

It is an open question whether potential gas purchasers have taken the lead in securing Alaskan pipeline ownership positions because they need to ensure a means to transport purchased gas to market, or because they view an equity position as a worthwhile investment in and of itself. Unlike most gas pipelines in which transport of gas is at the sole discretion of the owners, the Alaska gasline will be a "common carrier," meaning equal opportunity for gas shipments must be afforded all interested parties (just like the TAPS oil line). Hence, a gas purchaser who owns a piece of the pipeline gains no special benefits with respect to transportation access than does a non-pipeline owner. In regard to the desirability of pipeline ownership as an investment, the Alaska project has several unique features which may detract from the usual desirability of earning an assured rate of return as a regulated utility. These factors include the tremendous scale and technological uncertainties of the project, the uncertainty of delivered throughput and the imposition of a "variable rate of return" which subjects a company's profits to the risks of cost overruns. It appears likely that the opportunity to achieve a higher than normal rate of return will have to be afforded in order to compensate for these additional risks.

B. Gas Owners' Involvement

1. The Producers - Producers will not join the pipeline consortium as equity owners for two reasons. First, as previously mentioned, the integrated oil companies have

traditionally avoided downstream transportation and marketing of gas produced in association with oil. Second, the President, in his decision, specifically opposed producer participation in pipeline ownership, due to real or imagined anti-trust considerations raised by the Justice Department in its July, 1977, report to the President.

2. The State of Alaska - The President's Decision cast the State as a beneficiary of the pipeline, and assumed that the State would therefore find it in its interest to participate in pipeline financing, including consideration of investing risk capital in an equity position. The report argued that the State, like the producers, would benefit from the pipeline in that a pipeline would facilitate the sale of its royalty gas. In addition, the State stood to gain from an increased tax base, economic development, and jobs. Unlike the producers, the federal government appears to have found no anti-trust problems with State involvement in pipeline ownership.

C. Federal Government Involvement in Pipeline Ownership

It can be argued that the federal government has an interest in assuring the marketing of Prudhoe gas, so that its goals with respect to energy self-sufficiency through increased domestic production of oil and gas are met. However, the President and Congress have specifically mandated that no federal participation will occur. Congressional action would be required to change that decision. The decision was based on several factors, including a concern about risking taxpayer capital for the benefit of gas consumers, and a fear of setting a precedent for federal involvement in other large-scale energy projects.

POTENTIAL PIPELINE OWNERS

Gas Purchasers (Pipeline and distribution companies)

State of Alaska

D. The Composition of the "Alaska Highway Pipeline Project"

The "Alaska Highway Pipeline Project" (formerly Alcan) is a loose consortium of nine U.S. and Canadian companies, each with their own membership structures. These nine companies are organizing to construct eleven separate parts of the Pipeline Project which begins on the North Slope and ends in Illinois ("Eastern Leg") and California ("Western Leg"). These nine companies can, therefore, be expected to file at least eleven separate tariffs with the appropriate U.S. and Canadian agencies. The following pages portray these pipeline companies and their jurisdictions along the pipeline route.

The names of these pipeline companies and of their member pipeline and gas companies are a bit confusing. For example, "Alaskan Northwest" is the name of the newly formed company in charge of the Alaskan segment of the pipeline. "Northwest Alaskan" (a subsidiary of Northwest Pipeline of Salt Lake) is one of the six member companies of "Alaskan Northwest."

Some of these pipeline companies have been in existence for a long time (such as Pacific Gas and Electric), and are included in the Pipeline Project because they will be "looping" their existing lines[1] in order to carry the North Slope gas. Others, like Alaskan Northwest, are organizing as new pipeline companies

1/ "Looping" entails laying additional pipeline alongside an existing line to increase capacity.

(generally composed of new subsidiaries of existing pipeline and distribution companies) and will be laying pipe along routes where no gaslines now exist. These latter types of companies are continuing to develop their membership structures which will probably remain in flux until gas sales are consummated.

ORGANIZATION OF THE "ALASKA HIGHWAY PIPELINE PROJECT"

(1) Alaskan Northwest Natural Gas Transportation Company

members: Northwest Alaskan Pipeline Company ("operating partner")
(subsidiary of Northwest Pipeline Company, Salt Lake)

Northern Arctic Gas Company
(subsidiary of Northern Natural Gas Co, Omaha)

Pan-Alaskan Gas Company
(subsidiary of Panhandle Eastern Pipeline Co, Houston)

United Alaska Fuels Corporation
(subsidiary of United Gas Pipeline Co, Houston)

Natural Gas Corporation of California
(subsidiary of Pacific Gas and Electric, San Francisco

Pacific Interstate Transmission Company
(subsidiary of Pacific Lighting Corp, Los Angeles)

(2) Pacific Gas and Electric (existing company)

(3) Pacific Gas Transmission Company (existing company)

(4) Northern Border Pipeline Company (currently being organized by Northern Natural Gas Co, Omaha)

(5) Foothills Pipeline (S. Yukon) Ltd

members: Foothills Pipeline (Yukon) Ltd.[1] (100%)

(6) Foothills Pipeline (N. British Columbia) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Westcoast Transmission (49%)

(7) Foothills Pipeline (S. British Columbia) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Alberta Gas Trunkline (49%)

(8) Foothills Pipeline (Alberta) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Alberta Gas Trunkline (49%)

(9) Foothills Pipeline (Saskatchewan) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (100%)

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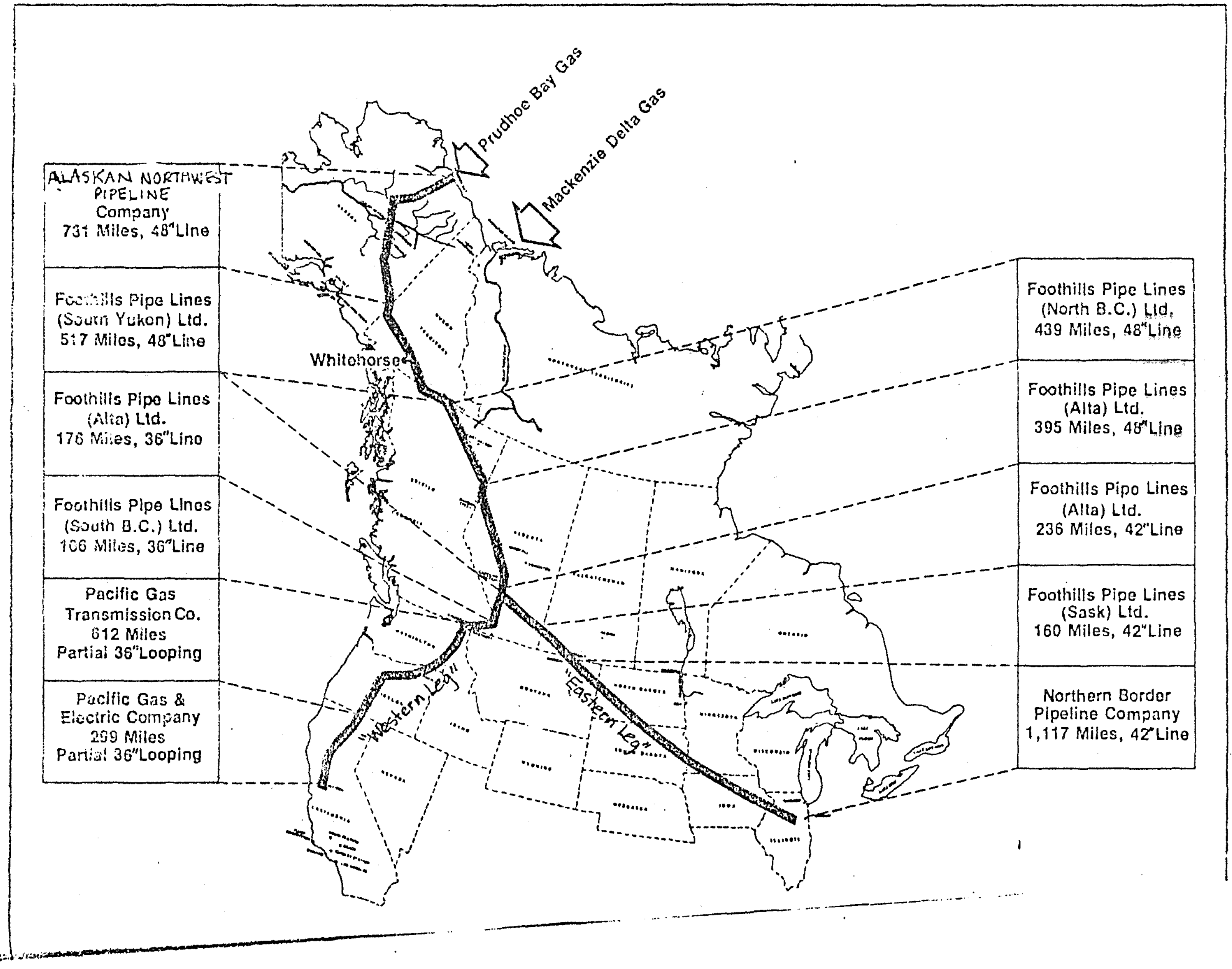
[1] Foothills Pipeline (Yukon) Ltd. maintains at least a 51% interest in each of the 5 "Foothills" pipeline consortiums. It is composed of 50% Alberta Gas Trunkline and 50% Westcoast Transmission.

COMPONENTS OF THE "ALASKA HIGHWAY PIPELINE PROJECT"



LENDERS

If a gas pipeline is constructed, it will mean that a sufficient quantity of equity and debt capital was raised to finance construction of the required production and transmission facilities. In addition to investment in the pipeline itself, a variety of investments (for gathering and conditioning and water injection) may be necessary in the Prudhoe field, "upstream" of the gas pipeline inlet. It will be necessary to allocate these field costs between gas production (which places the responsibility for securing capital upon the producers), and gas transportation (which places financing responsibility upon the pipeline owners).

A. Investors in Production Facilities

Equity will, of course, be provided by the producers, if the producers determine that the investment is worth the benefits to be gained at this time by sale of their gas. Debt capital would be raised from the private financial community. It is unclear as to what expectations FERC and the producers may have with respect to State participation in equity or debt arrangements. The State did not provide any capital during the construction of oil production facilities.[1]

1/ Senator Stevens at one point did advocate State participation in the conditioning facilities.

B. Investors in Transportation (pipeline) Facilities

The parties which may contribute equity as pipeline owners were discussed in the previous section on Transportation Companies. In addition to equity, there are several potential sources of debt capital.

1. Private - The private capital market is the most apparent debt investor.

2. Producers - FERC foresees investment by the producers in pipeline facilities as highly unlikely; especially since pipeline construction will necessitate concomitant field expenditures for gathering, conditioning, and water injection, much of which may be the unavoidable responsibility of the producers.

3. State of Alaska - Both the transportation consortium and the federal government are urging Alaskan investment in the gas pipeline.

4. Federal Government - The President's decision, and congressional approval thereof, prohibits debt or equity investment by the federal government.

5. The Pipeline Company - Presumably all capital (including borrowed capital) contributed by the member companies will serve as equity, as a high equity/debt ratio makes the debt investment more secure and hence easier to obtain.

POTENTIAL INVESTORS IN FIELD PRODUCTION FACILITIES

Equity:	Producers
Debt:	Private State

POTENTIAL INVESTORS IN TRANSPORTATION (PIPELINE) FACILITIES

Equity:	Pipeline Companies State
Debt:	Private State Producers (highly unlikely)

LANDOWNERS

The route of the pipeline will traverse lands held by the United States, Canada, several states and provinces, municipalities and private parties. Purchase or right-of-way lease of these lands must be negotiated between the pipeline company and landowner. The gas pipeline company has a great deal more power in so doing than did the TAPS oil company, Alyeska. This is because, unlike an oil line, an interstate gas line acquires condemnation powers upon receipt of its Certificate of Public Convenience and Necessity. Alyeska's only course of action was to appeal to a government entity to condemn lands on its behalf. These gasline condemnation powers likewise extend to Canadian companies which receive certificates from Canada's equivalent of FERC - the National Energy Board.

GOVERNMENT REGULATORS

United States	Canada
Congress	Parliament
Federal Energy Regulatory Commission (FERC)	National Energy Board
Department of Energy (DOE)	(Others not discussed here)
Economic Regulatory Authority	
Federal Inspector	
Executive Policy Board	
Other federal agencies	
Alaskan National Gas Pipeline Office	
State of Alaska	
State Utility Commissions	

The United States

Congress: The role of Congress in the Alaska gasline project essentially ended last November with approval of the President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System," which selected the Alcan route through Canada over two competing proposals. This action was taken pursuant to the provisions of the Alaska Natural Gas Transportation Act (ANGTA) of 1976.

FERC: The DOE and FERC were created by Congress last summer. FERC is an umbrella-regulatory commission, independent and responsible to Congress. FERC was given the powers of pipeline certification formerly held by the Federal Power Commission as well as the oil pipeline tariff authority formerly held by the Interstate Commerce Commission.

In December, pursuant to provisions in the ANGTA, FERC vacated the prior proceedings before the commission (filed by El Paso and Arctic Gas) and issued a conditional Certificate of Public Convenience and Necessity to Northwest.

FERC is responsible for federal oversight of the Alcan project prior to construction. Before construction can begin, FERC must issue a final Certificate of Public Convenience and Necessity. In the course of pipeline regulation since passage of the Natural Gas Act in 1938, actions of the FPC, the courts, and now FERC have resulted in development of a considerable body of law delineating the factors to be considered in making a determination to certificate a pipeline. Analysis and a satisfactory finding are required in each of these areas before certification: financing, tariffs, marketability (including setting a wellhead rate, if necessary), gas reserves and deliverability, processing and conditioning, accounting procedures and construction cost control. In fact, FERC can impose <u>any</u> terms and conditions to the certificate that it finds necessary to protect the public interest.

FERC also must consider environmental impacts of the project under the National Environmental Policy Act (NEPA). Having completed the EIS process, FERC's primary environmental responsibility now centers on "site specific" activities. FERC must consider and approve the location of the pipe and other design criteria which will mitigate environmental problems.

Department of Energy: The ANGTA places some responsibilities for this project in the DOE. Among these, DOE must develop an organization plan for the office of the Federal Inspector and define the relationship of that office to the Executive Policy Board (discussed below).

Joint DOE/FERC responsibilities: In addition to FERC's normal regulatory responsibilities regarding pipeline certification, the President's Decision gives FERC and DOE additional duties because of the unique nature of the project and its international implications. The required DOE/FERC areas of action include: choosing the size of the Eastern and Western legs of the pipeline, overseeing relations with Canada under the Bilateral Agreement, passing on any proposed predeliveries of Alberta gas, assessing the capacity requirements of the pipeline against the available Alaskan and Canadian reserves, and examining the proposed financing package in the light of national and international concerns of the United States.

Economic Regulatory Authority: The Economic Regulatory

Authority within DOE has the power to approve all exports and imports of gas. This means that ERA is involved in consideration of the so-called "Alberta gas swaps" in which early deliveries of Canadian gas will be made to the U.S. in anticipation of future North Slope gas being provided to Canada.

Federal Inspector: The office of Federal Inspector, created by the ANGTA, will exercise an expanded federal role in the project's management and construction. The President will appoint the Federal Inspector with the advice and consent of the Senate. Duties of the Federal Inspector include:

--establish joint surveillance and monitoring agreement with the State of Alaska;

--monitor compliance with laws, certificates, rights-of-way, permits, leases and other authorizations;

--monitor construction schedules, quality of construction, cost control, safety, environmental protection objectives; and

--keep Congress and the President informed on progress of the project.

The President's report to Congress contemplates a change in federal law to give the Federal Inspector field-level supervisory authority over the enforcement of stipulations, terms and conditions by those federal agencies having statutory responsibilities over various aspects of the project. In addition, FERC may decide to delegate its cost approval authorities to the inspector, so that acceptance of project costs for the purposes of tariff-setting will occur as the expenditures are made, rather than through the usual post-construction audit.

Executive Policy Board: The Federal Inspector will be subject to the ultimate policy direction and supervision of an Executive Policy Board, made up of the Secretaries of the Interior, Energy, and Transportation, the Administrator of the Environmental Protection Agency and the Chief of the Army Corps of Engineers.

Other federal agencies: All federal agencies will retain their existing authorities, pursuant to ANGTA, to issue original certificates, permits, rights-of-way and other authorizations, and to prescribe any appropriate stipulations, terms, and conditions permissible under existing law. Agency Authorized Officers, representing their respective federal agencies, will directly enforce the stipulations, terms and conditions--subject to supervision by the Federal Inspector.

Alaskan Natural Gas Pipeline Office: The Federal Inspector and Agency Authorized Officers will constitute an Alaskan Natural Gas Pipeline Office.

State of Alaska: State officials (staffed by a Pipeline Coordinator within the Department of Natural Resources) will cooperate with the Federal Inspector in establishing a joint surveillance and monitoring agreement similar to the one in effect during construction of TAPS. In addition, the State's regulatory authority will include these areas:

--Conservation laws: The State Department of Natural Resources, Division of Oil and Gas Conservation, and the Alaska Oil and Gas Conservation Committee (within DNR) have the statutory power to "prevent waste" of oil and gas produced in the State. This authority is a key factor which will determine how much gas is available for shipment through a pipeline. Pursuant to this authority, the Conservation Committee last

June issued Conservation Order No. 145, which approves an operating plan for the Prudhoe Bay field. The order approves offtake of 2.7 billion cubic feet a day of raw gas (which would yield pipeline quality gas of 2.0 bcfd) and declares that this offtake is "consistent with sound conservation practices based on currently available data." The order also says that "large scale source water injection will probably be necessary to maximize oil recovery." However, it does not make production of gas contingent on the installment of water injection facilities by the producers. "The offtake rates approved by the Committee at this time must be established without the benefit of production history," the order says. "Therefore, these offtake rates may be changed as production data and additional reservoir data are obtained and analyzed."

O. K. "Easy" Gilbreth, Director of the Division of Oil and Gas Conservation and chairman of its Conservation Committee, told a congressional committee last fall that the State believes "there is no sound technical reason to delay, provided that the operators adopt and implement a source water injection program by the time gas sales start. If the operators do not implement a source water injection program, then gas sales will have to be limited or postponed in order to avoid jeopardizing ultimate oil recovery."

Although the State has the authority to shut-in or reduce gas production to prevent waste, some fear that it may be practically or politically impossible to take such an action once the gasline is under construction or in place.

A bill pending in the Legislature (CSHB 830) by Representatives Chat Chatterton and Hugh Malone would transfer the State's conservation authority from the Department of Natural Resources to an independent agency.

--Right-of-way Leasing Act: Northwest will make application to the Department of Natural Resources seeking right-of-way certificates for portions of the pipeline that cross public State lands. If the State refused to grant these rights-of-way, however, Northwest could still obtain the land through condemnation powers it will receive upon final FERC certification.

--Alaska Pipeline Commission: The Alaska Pipeline Commission has no jurisdiction over the tariff charged for intra-state shipments of gas in an inter-state pipeline.

--Local hire: The State's "local hire" law, implemented by the Department of Labor, is currently under review by the U.S. Supreme Court.

State public utility commissions: Public utility commissions in the United States regulate sales in which the buyer and seller are both located in that State. For example, FERC will approve the sale of gas from EXXON to a pipeline transmission company. A State PUC will then approve the sale from that transmission company to a local distribution company.

Canada

Parliament: An Agreement between the United States of

America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, (sometimes called the Bilateral Treaty), was approved by the Canadian Parliament last year. The treaty covers a broad range of issues, including: a construction timetable, pipeline capacity, financing, taxation, tariffs and cost allocation, and regulatory authorities.

The Canadian Parliament in April approved the Northern Pipeline Act, which sets up a single regulatory agency for planning and monitoring construction of the Canadian segments.

National Energy Board: The NEB is FERC's Canadian counterpart and will have similar responsibilities and authority.

The NEB has broad discretion in deciding on applications of public convenience and necessity for pipelines. Canadian procedures for implementing a decision on the gas pipeline appear to be less complicated than U.S. procedures. The State Department and other federal agencies advised President Carter last summer that delays related to approval by regulatory authorities are less likely to occur in Canada than in the U.S.

The NEB already has established the pipe diameter and pressure for Canadian segments of the line.

III. ENGINEERING AND SCIENTIFIC CONSIDERATIONS: PIPELINE DESIGN AND FIELD ACTIVITIES

BACKGROUND

The design of the pipeline (and compressor stations) establishes thresholds for the volume of gas and its quality that may be transported through the line. The various elements of pipeline design, in turn, determine the field activities (conditioning) which must take place in preparing the gas for pipeline transport.

Questions relating to pipeline design and conditioning are based on two considerations:

1. What quality of gas is to be transported through the line; and
2. What is the volume of gas?

Resolution of these questions by the producers, State, FERC, investors and gas purchasers will require a complex balancing of economic and regulatory factors, as well as the technical characteristics of oil, gas, and transportation facilities.

A. Gas Quality

The Prudhoe Bay reservoir contains crude oil and "associated gas" in the form of "gas cap gas" (located above the crude layer) and "solution gas" (dissolved in the crude). The hydrocarbons in these gas and oil layers represent the entire spectrum.

For the purposes of this report, these hydrocarbons will be referred to as "dry gas," "gas liquids," and "crude oil" as follows:

DRY GAS	GAS "LIQUIDS" (NGL's)				CRUDE OIL
C^1	C^2	C^3	C^4	C^5	C^6 and higher
methane	ethane	propane	butane	pentane	

The purpose of the Northwest pipeline is to transport those hydrocarbon components that physically cannot, or economically will not, be carried in the existing TAPS oil line. These remaining components represent dry gas and gas liquids. The first question to resolve is, "What can TAPS be expected to carry?"

1. <u>Transport of Gas Liquids in TAPS</u>

Note: Most of the technical interpretations cited here are extracted from SOHIO and ARCO letters to FERC dated March 9, 1978, and March 27, 1978, respectively.)

a. <u>Physical Constraints for Transport of Liquids in TAPS</u>

Crude oil emerging from the Prudhoe Bay reservoir is extremely hot; however, the delivery temperature of crude to the TAPS line is regulated at no greater than 140 degrees F, with a maximum "vapor pressure"[1] of 14.7 psia[2] which is equivalent to natural atmospheric pressure at sea level. At a higher temperature, or if the crude composition resulted in higher vapor pressure qualities, then the line would be threatened by the presence of two "phases" of hydrocarbons--those which flow as a liquid, and those which flow as a vapor or gas. "Two-phase flow" in either oil or gas lines results in difficult and hazardous operating conditions.

While the crude cannot be allowed to enter TAPS at a temperature of more than 140 degrees F, it has a minimum temperature limit as well. Crude must be supplied to TAPS at a high enough temperature to ensure that by the time it reaches Valdez, it will not have cooled into an immobile sludge("wax" precipitates as the temperature cools.) SOHIO reports that this lower temperature threshold for pipeline entry is about 100 degrees F, ± 10 degrees; and ARCO reported the threshold at 105 degrees F.

Presently, the crude delivered to the TAPS line is at the maximum temperature (140). Under these conditions, SOHIO believes the line can carry much of the pentanes (no butanes or lighter components).

1/ Vapor pressure for oil is the pressure at which any decrease will cause the lighter hydrocarbons to enter the gaseous phase. This vapor pressure is determined by the composition of the oil. Oil with no NGL's will have a low vapor pressure. Oil with NGL's will have a higher vapor pressure.

2/ Pressure is expressed as psi, psia or psig. The differences will be ignored for the purposes of this report.

In summary, there are two competing physical factors which are considered by the producer in choosing whether and how much gas liquids to ship through the TAPS line. Reduction of crude temperature will allow more liquids to be carried; however, this means that in the event of a temporary pipeline shut-down, the risk that crude might turn into a semi-solid sludge will increase. Hence, there are very definite physical characteristics which limit the type and amount of liquids which TAPS can accommodate. It is safe to say that most pentanes could physically be put into TAPS and possibly some butanes.

b. Economic Constraints for Transport of Liquids in TAPS

Even if the maximum volume of butanes and pentanes were transported through TAPS in the crude stream, it may be a useless gesture. While TAPS can accommodate crude with a 14.7 psia vapor pressure, tanker limits are 14.0 and Los Angeles air pollution regulations set the maximum limit on crude to be stored there at 11.1. Lower vapor pressures are attained by removing the lighter liquid components. Hence, unless a butane/pentane purchaser is waiting in Valdez, these components are destined to greet the "thermal oxidizers" (otherwise known as flares). Transporting butanes and pentanes through TAPS for flaring in Valez is of questionable economic merit.

2. Transport of Gas Liquids in the Gasline

Once it is determined how much of the gas liquids TAPS can and will carry, the question turns to the physical and economic constraints of the gasline.

a. Physical Constraints for Transport of Gas Liquids in the Gasline

While oil lines (which transport hydrocarbons in a liquid state) are more comfortable transporting heavy hydrocarbons, gaslines (which transport hydrocarbons in a gaseous state) prefer the opposite end of the spectrum. ARCO maintains that under any realistic operating pressure and temperature for the proposed gasline, all the methanes (C^1), ethanes (C^2), and the propanes (C^3) can be shipped through the gasline, without fear of "condensation" (which would result in hazardous conditions of "two-phase flow"). The amount of butanes (C^4) and pentanes (C^5) which can be carried increases with the pressure of the line. For example, a 2160 psi gasline could carry everything--all the butanes and pentanes. However, technological concerns arise at this high pressure, as the highest pressure in which a pipeline has operated to date (for gas compositions and line diameters similar to those anticipated for the Alcan line) is about 1000 psi. 1260 is a more realistic assumption for the proposed Northwest line. ARCO projects that a 1260 psi line can carry about 25-60% of the butanes and none of the pentanes.

b. Economic Constraints for Transport of Gas Liquids in the Gasline

When negotiating sales contracts for methane gas, the producers and purchasers will determine whether it is in their respective interests to include liquid portions of the gas stream in the sale agreements--at least those liquids which physically can be transported through the gasline. Considerations will include marketability of liquids in the lower states, purchaser's downstream interests and the producer's alternatives for field operations fuels. While it is true that a molecule of ethane or propane has a higher heating value, expressed in British Thermal Units (BTU's) than a molecule of methane[1], it may or may not be of greater economic value as part of the gas stream or sold separately as petrochemical feedstock. Joe Moore of Bonner & Moore provided the following ball-park estimates of BTU values during conversations with the Feminist Oil Caucus:

C^1	(methane)	-	950 BTU's/MCF
C^2	(ethane)	-	1700 BTU's/MCF
C^3	(propane)	-	2100 BTU's/MCF

"Enriching" the methane gas stream by inclusion of these heavier hydrocarbons may impose downstream processing costs if the gas is destined for commercial or residential use. This is because distribution lines operate at low pressures and physically cannot carry heavier hydrocarbons without risking "two-phase flow" problems. Hence, propane and butane would need to be removed. Conceivably, ethane could remain in the stream (provided it had no higher value in an alternative use), and the gas company would simply inject useless inert gas to bring the BTU content down to minimum standards thereby

1/ Ethane (C^2) and propane (C^3) have more carbons (per cubic foot of volume) available for oxidation (burning) than does methane (C^1); hence, greater heating value.

increasing the volume (MCF's) available for sale.

In summary, there appears to be little debate that TAPS can physically carry all the pentanes (C^5) and heavier hydrocarbons; and that the gasline will be capable of shipping about half of the butanes (C^4). Subjecting this to possible economic considerations, it appears that at most half of the butanes and some or all of the pentanes(+) might have difficulty finding a way south under realistic operating conditions of both TAPS and the proposed gasline. Further, producers have maintained that these stranded hydrocarbons can all be used on the North Slope to fuel field operations.

3. Other Quality Considerations for the Gasline

In addition to the hydrocarbon components, Prudhoe gas contains several impurities. The most important impurities are carbon dioxide (CO2) and water (H2O).

a. Carbon Dioxide Considerations - Produced gas volumes are expected to contain roughly 12% CO2. There are several considerations which will determine how much of this CO2 is removed from the gas stream in the field.

Reasons to remove the CO2:

(1) CO2 has no BTU value, so shipment through the pipeline means that fuel will be used to move it and its presence reduces the amount of hydrocarbons that can be shipped each day.

(2) CO2 is corrosive if it combines with water, forming carbonic acid.

Reasons to not remove CO_2:

(1) CO_2 is a key ingredient in the manufacture of methanol and ethanol and might have some value for sale along the pipeline route.

(2) CO_2 might be injected into Alberta oil fields to increase production, or it might be used as an atmospheric additive to greenhouses. (Greenhouses may be constructed to utilize waste heat near the compressor stations.)

(3) CO_2 affects the dewpoint of the gas: a high CO_2 content means that line pressure must fall to a lower level before liquids condense--hence, CO_2 in the line means that heavier hydrocarbons can be carried.

b. Water Considerations - Water has no beneficial qualities to lend to the gas stream. The question is, rather, how much money should be invested to dehydrate the gas stream so that water problems can be minimized. Excessive amounts of water can cause two problems:

(1) Corrosion - If water mixes with CO_2, carbonic acid may form.

(2) Condensation - As the concentration of H_2O is increased in a pressurized gasline, droplets may form causing dangerous "two-phase flow" problems.

In summary, determining how much of the CO_2 and H_2O to remove from the gas stream is a matter of judgment and will require the balancing of physical, economic and regulatory considerations.

B. Volume of Gas

The amount of gas available for shipment through the gas pipeline will depend on several factors, the most important of which are the production rate of gas fields supplying the line and the amount of gas sold for shipment.

1. Production Rate

The President's Decision based its economic projections on a gas delivery rate to the pipeline of 2.4 billion cf/d from North Slope fields and 1.5 billion cf/d from Canadian fields. These assumptions need not be the basis by which FERC certifies pipeline capacity, and it is inevitable FERC will face difficult decisions in making the final capacity determination. The 1.5 billion figure for Canadian gas is totally speculative, since no one can predict when MacKenzie Delta production will be authorized and a spur delivery line constructed. The validity of the 2.4 figure has been questioned on several grounds:

(a) The approved operating plan for the Prudhoe Unit calls for offtake of 2.7 bcf/d of raw gas which would yield about 2.0 bcf/d of pipeline quality gas from the Sadlerochit reservoir. While that is the approved plan, it could be changed in the future if Prudhoe production characteristics prove different from today's expectations. The State's Oil & Gas Conservation Committee is charged to ensure that production is not wasteful of hydrocarbon resources.

(b) Dr. Todd Doscher, a legislative consultant and professor of petroleum geology at the University of Southern California, told a congressional committee last year approval of the gas pipeline should be delayed for three years until there has been time to assess reservoir performance. He stressed the importance of not committing the capital to construct the pipeline until there is absolute certainty the gas can be withdrawn without affecting ultimate oil recovery. Nevertheless, Congress gave the go-ahead to the Alcan project.

(c) The Kuparuk and Lisburne pools might supply additional volumes, but the producers have specified no plans for bringing these areas into production.

These problems and uncertainties will have a negative influence on investor interest in the gasline--particularly if the general economics are marginal.

2. Gas Sales

Produced gas will not be shipped through the pipeline unless it is sold by the gas owners (producers and the State) to purchasers who choose to use the line. The producers cannot be forced to sell their gas, and the purchasers cannot be forced to use the line. Presumably, if the gas is sold to the pipeline owners, those volumes will be shipped through the proposed gasline. However, if a purchaser secures the gas for use on the North Slope or upstream from the pipeline's Lower 48 outlets, then downstream capacity may be left unused, unless supplemental sources are found. Additionally, the spectre of using LNG tankers to transport the gas from the North Slope to markets has been raised.

In summary, FERC will certify that the pipeline be designed to carry an expected capacity, but determination of this "expected" capacity will be difficult.

PIPELINE DESIGN

The three major components of pipeline design are (1) volume capacity or "throughput," (2) quality specifications and (3) placement above or below ground. The background information relating to these factors was discussed in the previous pages.

A. Volume Capacity

The volume (measured in MCF's - thousand cubic feet) shipped through the gasline each day will be dependent upon "deliverability," which includes both the volume produced and the volume made available for shipment by the gas purchaser. The volume also will be affected by the pipeline design which controls how much the pipeline physically can carry. Presumably, these physical constraints of pipeline design are based on expectations for deliverability.

In viewing how pipeline design and volume capacity interrelate, another complicating factor enters the picture. The volume of gas shipped through the line each day is dependent upon three factors of pipeline design: pipe diameter, inlet gas pressure and "pressure drop." A range of diameter and pressure specifications[1] will be capable of carrying the same volume of gas throughput. As the diameter is increased, the pressure capabilities can be reduced. Hence, a 48-inch diameter line must operate at a higher pressure than a 56-inch line carrying the same volume of gas. Selection of pipe diameter and pressure will include consideration of differences in capital costs, variations in fuel efficiency for operations, and safety factors, in addition to consideration of how much gas will be available for shipment.

FERC is responsible for establishing the final pipeline capacity for the U.S. segments of the gasline; the National

1/ In general, the pressure specifications of a pipe are determined by the thickness of its walls and choice of steel.

Energy Board (NEB) is responsible for the Canadian portions. In so doing, these agencies must balance the need to ensure financibility (which requires that capacity is viewed conservatively, judging economic viability from committed rather than expected volumes) and the need to design a line which can accommodate future volume additions (which is a federal concern in that it relates to maximizing the availability of domestic energy resources). This latter concern for accommodating future volumes is important, because while the pipeline diameter and thickness of its walls, along with the capabilities of compressor stations, allow for some flexibility in throughput levels, it costs a tremendous amount to install additional compressors or to "loop" the line by laying a new line right next to the original.

The history of Alcan's proposal before the FPC (now FERC) last year demonstrates these competing concerns. Its initial application was for a 42-inch line in Alaska to carry 2.0 bcf/d. However, following the unfavorable decision in March by Judge Litt, Alcan amended its application to 48 inches, 2.4 bcf/d, like the competing Arctic proposal.

FERC has not yet established the volume capacity specifications for the United States segments; however, the NEB has done so for the Canadian portions. In February of this year, it determined that the line would be 56 inches with walls thick enough to operate at 1080 psi, based on an estimated throughput of 3.6 bcf/d (2.4 from Alaska and 1.2 from the as-yet undeveloped

MacKenzie Delta). The Canadian decision was influenced by the fact that only one of Canada's two pipe mills could produce 48-inch pipe, while both could roll 54-inch or 56-inch pipe.

While the NEB decision does affect FERC's choices for U.S. pipeline design capacity, a variety of diameters and pressures can be built in Alaska to transport 2.4 bcf/d to Canada. Furthermore, one can expect that throughput specifications will continue to be examined by FERC since the NEB decision can be changed prior to final certification by both countries, and the Canadian-U.S. "Bilateral Agreement" specifically mandates cooperation between these two regulatory bodies.

B. Quality Specifications

Based on the line operating pressures and risk and safety considerations, FERC will establish quality standards for gas offered for shipment. Specifications may include:

(1) dewpoint - specifying the maximum BTU level and the amount of heavy hydrocarbons allowable.

(2) impurities - specifying the maximum amount of CO_2 and H_2O that may remain after conditioning of the raw gas.

(3) temperature - specifying the required temperature of the gas stream (as it must be chilled to prevent problems in areas where the line is buried in permafrost).

(4) pressure - specifying the required compression necessary.

C. Placement Above or Below Ground

Under normal environmental conditions of the United States, the best way to lay pipe for gas shipment is to bury it in the ground. However, Arctic and sub-Arctic conditions present unique problems. In permafrost areas, hazards posed by frost heave and differential melting raise technological questions as to the feasibility of burying the pipe--even if gas is chilled below freezing before it enters the pipe. If risks are substantial, FERC might require those sections of the line to be elevated above ground level like much of the TAPS oil line. A significant amount of elevated pipe would substantially increase the cost of the line and exacerbate security problems which could pose even greater hazards than the elevated TAPS oil line.

FIELD ACTIVITIES

(including gathering, conditioning, and water injection)

Those activities which will take place prior to shipment of gas in the pipeline will be determined by the pipeline design. These activities include:

(1) gathering - which is the transportation of gas from the numerous wells in the field to the conditioning facilities and to the gasline, by means of non-regulated, producer-owned gathering lines.

(2) conditioning[1] - which includes a variety of processes for turning the raw gas into "marketable quality" and further into "pipeline quality" (dewpoint, impurities, temperature, pressure).

1_/ "Processing" has sometimes been used interchangeably with the word "conditioning." However, it has also been used to describe the dewpoint portions of conditioning activities; or it is used to denote the downstream extraction of gas liquids and upgrading into petrochemicals. Due to these ambiguities in meaning, the word "processing" will be avoided here.

(3) water injection - Though not a part of gas conditioning itself, the production of the gas cap and subsequent sales probably will require that a water injection facility is built to restore pressure to the field necessary for optimum oil production.

FERC will determine who will be responsible for raising the capital for field gathering, conditioning and water injection facilities. Those facilities which FERC attributes to gas "production" must be built by the producers (and will not be regulated by FERC). Those facilities which FERC allocates to gas "transportation" must be built by the pipeline owners (and will be regulated by FERC and included in the pipeline tariff). In making this decision, FERC must consider not only the basic arguments of what constitutes production and processing of raw gas into a marketable product and what constitutes upgrading of the marketable product into a transportable product, but it must also consider several policy questions, including the following:

(1) EIS - The Alcan environmental impact statement did not examine the impacts of the upstream facilities for conditioning. If any of these facilities are subsequently deemed to be part of the pipeline, then the existing EIS may be inadequate.

(2) Non-owner access to the conditioning plant - If the producers must build the conditioning plant, then it is not subject to FERC's jurisdiction. Questions have been raised as to whether this might necessitate the duplication of conditioning facilities by non-Unit leaseholders and future Beaufort leaseholders on the North Slope.

(3) Overall project viability - The Northwest project can move forward only if the producers are willing to sell their gas and if the investment community is willing to furnish debt capital for the pipeline.

Producers argue that if they must build conditioning facilities, they might decide the investment at this time is not worth the gains to be made from gas sales. On the other hand, Northwest argues that if the total capital required for pipeline construction increases due to inflationary delays or other reasons, then they might not be able to raise sufficient debt. These problems are discussed in more detail in the pricing and financing sections of this report.

IV ECONOMIC CONSIDERATIONS:

PIPELINE FINANCING, GAS PRICING, AND TARIFFS

Whether the Alcan line is a sound investment will be influenced by the ultimate market value of the gas. This market value is determined not only by the economics of the free market, but also by government regulation of pricing and tariffs. Expectations of the ultimate market value will determine (a) whether the gas is sold, and (b) whether the pipeline is financed.

It is difficult to determine with any certainty how much the free market would pay for Alaska gas. There are uncertainties within the free market itself (the price of alternative crude-based fuels in 1990, for example) and uncertainties about what course the federal government will take in regulating gas and other energy prices.

Domestic production of natural gas began declining in 1972. There has been a growing shortage of gas since 1971, and the shortage reached serious levels in the winters of 1975-76 and 1976-77.

The direct cause of this shortage was price regulation by the Federal Power Commission (FPC). By maintaining an artificially low price, the FPC made natural gas the choice fuel. The demand for gas has grown at an annual rate of 5.3 percent since 1970. At the same time, low prices depressed supplies by removing incentives for exploration. Total U.S. gas reserves fell by about a third between 1967 and 1976.

Under the Natural Gas Act of 1938, the FPC was authorized to regulate the transportation charges of the interstate pipeline companies. As prices paid by consumers began increasing, pressure was brought on the FPC to extend controls to wellhead prices. The FPC refused to extend its jurisdiction until 1954, when the Supreme Court ordered it to regulate the price of gas sold to interstate pipelines (Phillips Decision).

Prices were held at very low levels through the 1960s. The average new contract price was only 19.8 cents per mcf in 1969. The FPC allowed prices to rise somewhat in the early and mid-1970s in response to shortages, and new contract prices averaged 60 cents in 1975. The price of gas was still far below its free market level. The world price of energy in 1975 was about $12 per barrel, but 60-cent gas is equivalent to oil at $3.50 a barrel.

In June, 1976, the FPC issued Opinion 770, a decision that set the national area rate for new contracts at $1.42 per mcf, with future price increases of 4 cents per year. This decision was challenged and upheld in the courts. The new contract price in 1977 averaged about $1.46 per mcf, which is equivalent to oil at about $8.50 per barrel, well below the world market price.[1]

1/ Information and statistics in this section are taken from the book, Options for U.S. Energy Policy, by the Institute for Contemporary Studies, 1977; specifically from the chapter, "Prices and Shortages: Policy Options for the Natural Gas Industry," by Robert Pindyck.

Looking to the future, it is not clear which direction federal policy will take. On one hand, some argue that the federal government should reduce its role as a regulator and allow the free market to operate. However, others argue that the federal government should continue its historic role in regulating gas prices.

Market value is basically the price the consumer is willing to pay (assuming he has a choice). This is influenced by two factors: (1) What are his alternatives (including other fuels and other gas sources)? and (2) What actions has government taken to subsidize certain energy supplies through devices such as rolled-in pricing (averaging high-cost supplies with low-cost supplies)?

The producer must then determine whether the price the consumer is willing to pay is high enough to meet his perceived value of the gas at the wellhead and the cost of transporting it to market. In a strictly free market system, the wellhead value is what the consumer is willing to pay, less the cost of transportation to market. However, in our regulated system, government restricts selling price through imposition of a wellhead ceiling. In the case of Alaska where transportation costs are extremely high, the wellhead value may be below the ceiling, and therefore the ceiling would not function. For example, the North Slope oil producers receive an average of between $5.00 and $8.00 per barrel for their oil despite a federal ceiling of more than $11.00.

If the consumer determines the gas will cost him more than he is willing to pay (market value), or if the producers determine that the wellhead value is unreasonably low and better options may exist in the future, then gas sale contracts may not materialize. In the event these gas sale contracts do not materialize for economic reasons, the government might choose to use its regulatory powers to enhance the saleability of Alaska gas if the importance of a secure domestic source outweighs other considerations. For example, rolling-in the high-priced Alaska gas with lower-priced gas from regulated domestic sources would make the Alaska gas cheaper, and therefore more attractive. The government also will have the power to encourage or limit the availability of other alternative gas supplies like SNG, LNG imports and Canadian and Mexican gas.

In spite of all government actions to manipulate the free market through regulation and facilitate the consummation of gas contracts, the gasline will not be built unless the financial community believes it is a worthy investment.

The financial community normally decides whether to invest in a project based on its economic viability. In the case of the Alcan line, viability may hinge on government manipulation of the free market system. Even though the purchaser (generally a Lower 48 utility) may be willing to pay a "rolled-in" price for Alaska gas, the financial lenders and investors can be expected to take a more conservative approach if the project is not viable on its own economic merits. The scale and uniqueness of the project, the large amount of money involved, and the technical, marketing and regulatory uncertainties further increase the risk for investors.

If the financial community believes the project is not viable in a traditional economic sense, it still might be willing to invest if the federal (or State) government agreed to provide the ultimate financial backstopping to assure debt recovery.

Congress and President Carter, however, have explicitly ruled out federal financial participation and have relied on assurances from Northwest that the project can be "privately" financed. The federal government believes its financial participation in the project is unwise for a number of reasons, and therefore, a reversal of the federal stance is unlikely until Northwest has exhausted all avenues--and failed.

The President's Decision

Private financing: President Carter's "Decision on the Alaska Natural Gas Transportation System," which was approved by Congress last fall, states that the pipeline must be privately financed. Privately financed in this sense means non-federally financed. It does not exclude state participation. The Decision explicitly rejects federal participation and states that consumers will not share any risk prior to completion of the pipeline. The Decision specifies that producers of Alaska natural gas may provide guarantees for project debt but may not own any portion of the pipeline, which would result from contribution of equity capital. The prohibition against equity participation by the producers was based on anti-trust complications raised by the Justice Department.

A report to Congress accompanying the Decision says the "direct beneficiaries" of the project have sufficient credit support capacity to assure completion of the pipeline without assistance from consumers. Such direct beneficiaries, the report says, are the gas transmission companies, gas producers and the State of Alaska.

Cost: The President's report to Congress says the pipeline is expected to cost about $10.3 billion, adjusted to reflect commencement of operations on January 1, 1983. With a 32% overrun, total capital requirements would rise to about $13.6 billion, the report says. The Alaska section of the line is projected to cost $3.7 billion, not including expected overruns. A 32% overrun would add about $1 billion to the cost of the Alaska segment. (These figures include a one and one-quarter year lag in outlays and a 5% inflation factor.)

The report sets out a four-part plan to effectuate private financing and balance the project's risks and benefits:

1. Equity investment is to be placed at risk under all circumstances, and the budgeted equity investment is to be considered the first money spent. The rate of return on equity will compensate sponsors for bearing this risk.

2. Producers and the State of Alaska, as direct and major beneficiaries of this project, should participate in the financing either directly or in the form of debt guarantees.

3. The burden of cost overruns is to be shared by equity holders and consumers upon completion through the application of a tariff based on a variable rate of return on common equity.[1] This would provide a strong incentive for the project to be constructed at the lowest possible cost.

4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences, sometimes called a "minimum bill" tariff.

Marketability and Economics

The President's Report to Congress says the pipeline project is economically sound and that even in the event of extreme cost overruns, the delivered cost of Alaska gas will be economically attractive. The conclusion that Alcan can be privately financed is founded on the basic economic desirability of Alaska gas and the viability of the Alcan transportation system; nevertheless, "skillful financial packaging and risk-benefit balancing will be required," the report says.

However, three legislative consultants have challenged the assertion that the Alcan project is economically viable.

Consultant Joe Moore of Bonner & Moore told the House Special Committee on Royalty Oil and Gas April 5th that Alaska gas delivered through Alcan will not be able to compete in the

1/ On May 8, 1978, FERC published a "Notice of Proposed Rule-making" seeking comments on proposed ways to structure the variable rate of return. Comments are due June 14th.

Lower 48 unless the government "circumvents and manipulates" the free market through rolled-in pricing. Moore estimated Alaska gas will cost about $5 per million btu's (mmbtu) at the end of the Alcan line, assuming Alcan and downstream distribution tariffs of $3.50 and a wellhead price and conditioning charge of $1.50. This is twice as high as the comparative cost of crude oil at $2.50 per million btus, Moore said. Consumers will not buy Alaska gas unless its high price is averaged in with the lower-priced, regulated gas produced in the Lower 48.

Consultant Todd Doscher, who worked as a consulting petroleum engineer for Shell Oil for 25 years before becoming a university professor and consultant, told the House Special Committee on Royalty Oil and Gas April 14th it is unlikely Alaska's gas will be competitive in the Lower 48 markets in the near future. Doscher released to the committee a report that he and about 35 other geologists and engineers prepared for the Department of Energy during the last year. The report shows there is a possibility that in the next 20 years 200 trillion cubic feet of unconventional natural gas could be recovered from the Tight Sands of the Rocky Mountains at a price of less than $3 per mcf. Half of that amount, 100 trillion cubic feet, could be recovered at a price of $1.75 per mcf, he said. This study will be validated in two to three years, and if it proves to be true, this would be a large, competitive source that would undercut the marketability of Alaska gas, Doscher said.

"I think you have to check on this matter before you go committing your money to the pipeline that just may possibly sit idle for 10 or 15 years until this gas supply from unconventional sources is used up," he said. Even if the Alcan line could be built for $10 billion, the lowest amount anyone is predicting, the delivery cost to market will be in the range of $2 to $3 per mcf, he said. This would mean a city-gate cost in the range of $4 to $5 per mcf, including the wellhead value and conditioning. This price will not be competitive, he said.

In addition, Doscher said he believes that a price of $3 per mcf would stimulate production of 25 to 100 trillion cubic feet of gas from conventional sources.

From now until the year 2000, Doscher said, it is likely that gas can be supplied for less than $3 per mcf with the possible exception of California markets.

Consultant Arlon Tussing also has questioned some of the federal government's basic assumptions relating to the project's economic viability and the probability of private financing.

In general, Tussing says, natural gas is worth the price of its nearest substitute (number two fuel oil). Consumers generally will pay anything up to that price, but not much more. The supplementary gas projects now under consideration--such as SNG, coal gasification, LNG imports and Alaska gas--are expected to cost about $4 to $6 per million BTU's (1977 dollars).

It is widely assumed by leaders in government and industry that the world supply of oil will tighten by the mid-1980s and that the real price of oil will rise throughout the late 1980s and 1990s. It is further assumed that coal gasification, LNG projects, and pipelines from the Arctic do not have to meet the test of <u>today's</u> oil prices, but make sense even if they cannot deliver energy except at considerably higher real costs. Although this outlook may be the most probable one and the most prudent basis for public policy, Tussing says, there are other plausible scenarios in which the real price of oil will <u>not</u> rise and might even fall. What is the <u>correct</u> forecast is beside the point: there remain genuine uncertainty and serious controversy over the future course of oil prices, and they will (and should) influence the attitudes of institutional lenders toward the creditworthiness of major gas supply contracts, Tussing says.

It has also been argued and assumed that rolled-in pricing will assure the marketability of Alaska natural gas, even if it is more costly than alternative energy sources in the mid-1980s. It is true that gas transmission companies and distributors are now contracting to pay up to $5 per mmbtu for supplemental gas supplies. Regulated gas companies are willing to pay more for supplemental gas only because the expensive supplements can be rolled together with the price of domestic "old" and "new" gas, whose regulated prices are considerably lower than their market value, Tussing says.

The marketability of Alaska gas requires an adequate margin of low-priced gas through the 1980s to subsidize transportation of gas from Alaska. While a reasonable case can be made that the margin will be adequate, there are other plausible scenarios in which little or no margin will be left for rolled-in pricing to assure the marketability of gas that enters Lower 48 distribution systems after 1981.

Deregulation of new gas, for example, would allow gas distributors to bid up the price of new gas supplies to levels at which the average price of all gas approximates its market value. Even without deregulation, Tussing says, the growing portion of higher-priced "new" gas, Canadian and Mexican pipeline imports and other more costly supplemental supplies could well wipe out the margin between the average price of gas under existing contracts and the price at which gas can be sold, as soon as the early 1980s.

Regardless, Tussing says, lenders are not going to know what will happen to the regulatory system or to the price composition of U.S. gas supplies over the economic life of the Alcan pipeline, and they will not finance any system whose viability depends both upon a continuation of price controls on conventional natural gas and upon a relatively slow movement of higher cost unconventional supplies into the distribution system.

Tussing believes that regardless of the decisions Congress and FERC make about natural gas pricing, including the pricing and rolling-in of Alaska gas, lenders will require the Alcan project to be viable under the assumption that it would be competitive on an <u>incremental</u> price basis. If the Alcan pipeline is to be financed by conventional private means, Tussing says, the average cost in constant dollars of that gas, delivered to its final consumers, cannot be higher than the price of No. 2 distillate oil on the world market. Moreover, lenders must be very confident that capital cost overruns, delays and production problems will not be severe enough to run the delivered cost of the gas so far above the expected value that it is unmarketable.

There is no way lenders can be given such an assurance, Tussing says. The maximum market value of natural gas is now no more than $2.60 to $3.00 per mmbtu. Assuming the higher figure, a wellhead price of $1.48 (congressional compromise) together with the estimated Alcan tariff of $1.04 (President's report) would leave only 51 cents for gas conditioning, transmission beyond the tailgate of the Alcan system, storage and distribution.

Therefore, there are wholly plausible assumptions under which the Alcan system might <u>not</u> deliver marketable gas and would <u>not</u> meet a conventional cost-benefit test, and in which its net national economic benefit, conventionally measured, would be zero or negative, Tussing says. However, he says this does not imply that some other system should be approved for transmission of North Slope gas, or that no system should be built. The immediately relevant and pressing conclusion, however, is that the prospects for purely private financing are actually quite slim.

Attitude of North Slope producers concerning financial participation:

Despite President Carter's invitation to the North Slope producers to share a portion of the debt for the project, it appears highly unlikely any of them will do so. (The President's Decision prohibits equity participation by the producers.)

Claude Goldsmith, Vice President of ARCO, told a congressional committee last fall his company does not intend to help pay for Alcan: "Aside from the possibility of anti-trust legislation and the political climate regarding divestiture, the economic attractiveness of investment in an Alaskan transmission facility has been severely dampened for Atlantic Richfield, and, presumably, for the investment and banking community, by the recent proceedings fixing tariffs on the trans-Alaska oil pipeline. The Interstate Commerce Commission there reversed, without hearing, a methodology for computing pipeline tariffs which had been commonly employed and accepted for 35 years. Under these circumstances, Atlantic Richfield is currently of the opinion that its financial participation in a gas pipeline system for transportation of Alaskan gas would be ill-advised."

Under the proper circumstances, Goldsmith said, ARCO would not be opposed to financing a portion of the gas conditioning plant. However, a prerequisite to such investment would be the fair and non-discriminatory treatment of Alaskan producers as to wellhead gas price and a return on gas conditioning plant investment comparable to that which will be received by the owners of the gas transmission system. ARCO's participation also is conditioned upon investment by others in the venture.

Business Week recently (April 10, 1978) quoted SOHIO ex-chairman Charles Spahr on the possibility that SOHIO will invest in the gas line: "SOHIO is unable to undertake such a risk even if it wanted to do so, which it certainly does not."

Pricing Methods

In setting a wellhead price for gas, the FPC traditionally used a "cost-based" method, which is based on the producers' costs in developing and producing gas from the field.

Cost-based pricing is somewhat arbitrary when it is applied to gas that is produced in association with oil (associated gas), because it is impossible to determine precisely the costs of finding, developing and producing only the gas. Therefore, the FPC in recent years has set the price for gas based on the cost of producing only non-associated gas (gas not produced in association with oil), and then has allowed the same price to be paid for associated gas produced in that area.

Alaska gas is produced in association with oil. Therefore, if FERC were to set the price for Alaska gas under the Natural Gas Act, complex and lengthy hearings would be required to allocate costs between oil and gas production, a procedure which has not been attempted since the mid-1960s. The President's Decision says that procedure likely would take more than 18 months.

The President's Decision urges that Congress adopt a "commodity-value" pricing method for North Slope gas as set forth in the administration's proposed National Energy Act, which still is stalled in a House-Senate conference committee.[1] The National Energy Act would amend the Natural Gas Act and set the rate for Alaska gas at $1.48 per mmbtu, subject to annual escalation equal to inflation.

If Congress fails to adopt the National Energy Act or some substitute for it, FERC will set the price for Alaska gas under the Natural Gas Act of 1938.

The "commodity-value" approach proposed by Carter apparently would calculate the wellhead or netback price by subtracting the cost of transportation from the value of the gas at the city gate, as determined from the cost of alternative fuels. Netback pricing is intended to assure the marketability of the gas, although it would be workable only if the expected netback price were high enough to cover field development, transportation and gas processing costs. The President's report is vague on how this method would actually work.

The President's report estimates that the wholesale or "city gate" price for North Slope gas will be about $2.50 to $2.80 per mmbtu (in constant 1975 dollars), assuming a 40% cost overrun in building Alcan. It should be noted that this represents the average tariff over the 20-year life of the line. However, the initial tariff during the early years will be higher,

1/ As of June 2, a congressional House-Senate Conference Committee had reached agreement in principle on major items and policy relating to natural gas pricing, which is one section of the five-part National Energy Act. The conference committee has yet to resolve more than 30 "technical" items. After agreement is reached on all items, from four to six weeks will be needed to draft the agreement into bill form. Most observers predict Congress will not take final action on the natural gas compromise until August or September.

thus further impeding marketability.

The report projects the delivered cost of Alcan gas under three different overrun assumptions:

20-Year Average Alcan Delivered Cost
(1975 dollars)

	Field Costs	Expected 40% Cost Overrun	Worst Case Cost Overrun
Field Price	$1.45	$1.45	$1.45
Processing	0 to .30	0 to .30	0 to .30
Transportation (Alcan tariff)	.80	1.04	1.57
Delivered Cost:	2.25 to 2.55	2.49 to 2.79	3.02 to 3.32

(These calculations are based on a throughput volume of 2.0 to 2.5 billion cubic feet per day.)

The President's report says conservatively projected costs of imported LNG and other alternative non-conventional gas supplies would be at least $3.25 per mmbtu (in 1975 dollars). SNG would be at least $3.75 per mmbtu. Only if there were a "worst case" cost overrun and high processing costs would Alaska gas be more expensive than imported LNG; it would still be considerably less expensive than SNG.

Therefore, the report concludes, the Alcan project would appear to be competitive for the life of the project.

The $1.04 tariff assumed in the President's report is a 20-year average over the life of the project. John McMillian, Chairman and Chief Executive Officer of Northwest Alaskan, said at a Juneau press conference April 15th that the tariff in the early years of the project is now expected to be about $2.22.

A tariff of more than \$2 could mean a city-gate price of more than \$5: \$1.45 wellhead value + 75 cents gathering/conditioning + \$2.22 tariff + 75 cents storage and distribution charges = \$5.17.[1]

Elements that affect the value of Alaska gas: A number of variables and unresolved matters make it almost impossible to determine, at this point in time, the value of Alaska gas, or the amount of money the producers and the State will receive from sales of the gas. It is for this reason the North Slope producers have been unwilling to negotiate sales contracts.

Gas "commitments" were negotiated between the producers and gas purchasers several years ago in order for the pruducers to obtain front-end capital (advance payments) to assist their pipeline and field development. These "commitments" were not specific on price and have since been invalidated.

Wellhead price ceiling: The wellhead ceiling (assuming one is established by Congress) will not necessarily be the price the producers will receive from sale of the gas. If the transportation and processing costs exceed the purchasers' expectations of the value of the gas when it is delivered to the city gate, then it is possible the producers will only be able to negotiate sales contracts which offer less than the ceiling

1/ These (and any) dollar figures used in projecting tariffs must be taken at face value until it is specified which reference year is used. For example, \$1.04 is probably referenced to the value in 1975 dollars since that was when FPC developed the estimate; whereas \$2.22 may represent dollars inflated to the start-up year of 1983.

price.

It has not yet been determined by Congress or FERC whether gathering and conditioning costs can be charged to gas purchasers on top of the wellhead ceiling price, if, indeed, any purchaser would be willing to sign a contract at that price.

The latest version of the compromise energy legislation pending in Congress (as of June 2) would extend FERC's current authority to determine whether costs of compression, gathering and processing should be included in or added onto the ceiling price.

Consultant Joe Moore told the House Special Royalty Oil and Gas Committee that the North Slope producers probably will be very happy if the ultimate price they receive is $1 per mmbtu. This is because regardless of government-established price ceilings, the market value may be less. If this is the case, not only will the ceiling price become a moot question but producers may lose all interest in selling <u>any</u> gas at this time.

<u>Gathering and conditioning costs</u>: Estimates of gathering and conditioning costs vary widely. The President's report indicates that processing costs which may be assignable to gas are in the range of 0 cents to 30 cents per mcf.

FERC, in published comments on the President's report, says: "In the absence of definitive gas purchase contracts, uncertainties still remain as to whether the purchasers will have any obligations for the gas gathering and processing costs. Uncertainties also remain as to the handling of revenues attributable to the extracted liquids. Furthermore, it is still unclear whether the gas purchase contracts would provide additional gas-processing rights after the gas leaves the North Slope of Alaska. The gas purchase contracts to be negotiated between the producers and gas purchasers should address these issues."

Joe Moore told Representative Miles' committee that gathering and conditioning costs have been quoted by the North Slope producers ranging as high as $1.30 per mmbtu. Moore said he thinks it is reasonable to assume the costs will not be less than 50 cents, probably around 75 cents.[1] These costs are much higher than those assumed in the President's report.

Water injection: If gas is sold and not reinjected into the reservoir, injection of water from an extraneous body, in addition to reinjecting water produced from the field, may be required. The producers estimate these large-scale extraneous water injection facilities will cost more than $1 billion.

The Prudhoe Bay operating plan approved by the State contemplates that water injection from sources outside the pool will be instituted before production of gas for sale, although it does not require it.

FERC's comments do not resolve anything: "We are unable at this time to describe precisely how the costs of water-injection

1/ One problem in comparing conditioning cost estimates is that the processes included within that term may differ among parties making the estimates.

facilities should be balanced against the costs of gas-processing facilities, but some consideration is required. This view is expressed, however, in the context of not yet knowing the final course of reservoir management, the extent of the facilities required to implement the required operations, and the provisions of the purchase gas contracts."

Rolled-in versus incremental pricing: Northwest Alaskan officials have argued that rolled-in pricing of Alaska gas is "essential to ensuring the marketability of Alaskan gas and creating a positive atmosphere for achieving private financing for the system." Failure to mandate rolled-in pricing of Alaska gas will cause unreasonable delays and create an unfavorable market climate for the entire industry, Northwest officials have said.

Under rolled-in pricing, high-cost gas is averaged into the price of low-cost, regulated gas. Incremental pricing means the purchaser pays the full cost of the gas.

The latest version of the pending energy compromise would provide rolled-in pricing for the $1.48 wellhead and costs of transportation. However, certain charges that are permitted to be added to the wellhead ceiling price (increases in state severance taxes and costs of gathering/conditioning in excess of the wellhead) would be passed through on an incremental basis to industrial and other low-priority users.

Deregulation: The pending compromise provides for a phased deregulation of new gas prices, with all controls lifted in

1985. At the time President Carter's Decision and report to Congress was issued last September, the administration opposed deregulation: "If....proposals to deregulate natural gas prevail, serious uncertainties and delays concerning the development of any Alaskan natural gas transportation project could result." Carter now supports a deregulation compromise.

The effect of deregulation (if enacted) on the financial viability of the Alcan project appears to be detrimental, since deregulation and higher prices for domestic gas supplies will decrease the "margin" for rolling-in high-cost Alaska gas.

Tariff: Tariffs are the instruments through which the gas pipeline owners recover costs of service and a return on their total investment. It is the adequacy of this mechanism tempered by expectations of financial risks that private lenders will examine in deciding whether to lend money, since it is through the tariff that the owners obtain the funds to service debt and interest payments. Final approval of the forms of the tariffs rests with FERC.

The President's Decision says an "all-events" tariff, in which consumers guarantee at least the repayment of debt capital and interest (and possibly equity) in the event the project is not completed, is unnecessary and unwise. Instead, the President's plan recommends that FERC consider a tariff structure where consumers would pay debt service in the event of gas-flow interruptions only after the project is completed and initial operations of the delivery system have commenced ("minimum-bill" tariff).

Types of tariffs	Payment in the event of pipeline non-completion	Payment in the event of completion and subsequent gas-flow interruption
"all events"	consumers repay debt and possibly equity	consumers pay debt and equity depreciation charges
"minimum bill"	no payment	consumers pay only debt depreciation charges

The President's Decision also requires that the tariff include a variable rate of return as an incentive device to control cost overruns: the lower the cost overrun, the higher the return to the equity holder. This concept is untried in regulatory practice and the details must be worked out by FERC. The President's report suggests this variable rate of return on equity should be as high as 15%, rather than the more normal 12.5% to 14% found in recent FPC decisions. The impetus for this decision is the TAPS line. It is argued that since Alyeska knew it could recover all expenditures in its tariff, it had little incentive to minimize overruns.

Leveling the tariff: The President's report discusses the possibility of "leveling" the tariff. Normally, the cost of service (which generally includes depreciation charges and operating costs) decreases steadily over time, notwithstanding inflation. This is because as investment is depreciated and debt is repaid, both the interest charges and the rate base against which the owners are permitted to earn profits (a "return") diminish. Therefore, most tariffs are designed so that initial tariff charges are higher in the early years than in the later years.

A "levelized" tariff, in which the tariff remains the same (front-end years less than normal, and later years greater) would reduce the initial marketability problems. However, a leveled tariff would mean either that the rate of return on the pipeline would be reduced in the early years and deferred until later years when it would rise, or that special capital structure arrangements would have to be worked out in order to defer some capital charges until later in the pipeline's life.

The President's report says a complete leveling of the tariff would increase the cost of gas to consumers about 20 percent over the life of the project, because the total interest burden would be increased.

The decision whether to level the tariff must be made by FERC in the context of actual financing and tariff proposals made by applicants prior to final certification.

<u>Other tariffs, storage and delivery charges</u>: Once the gas reaches the end of the Alcan line, there will be additional charges for transporting and delivering it to the burner-tip, or the ultimate consumer. These charges depend on where the gas is going, and FERC estimates the charges could range as high as 75 cents per mcf.

V. TIMING AND RELATIONSHIPS OF GASLINE EVENTS

An understanding of the sequence and cause-and-effect relationships of the various gasline events provides the perspective for dealing with any particular issue. The attached diagram attempts to portray these events and relationships. While it demonstrates that their progression is by no means a single, simple chain, it nevertheless indicates that these events are not hopelessly enmeshed in a complex web of interrelationships.

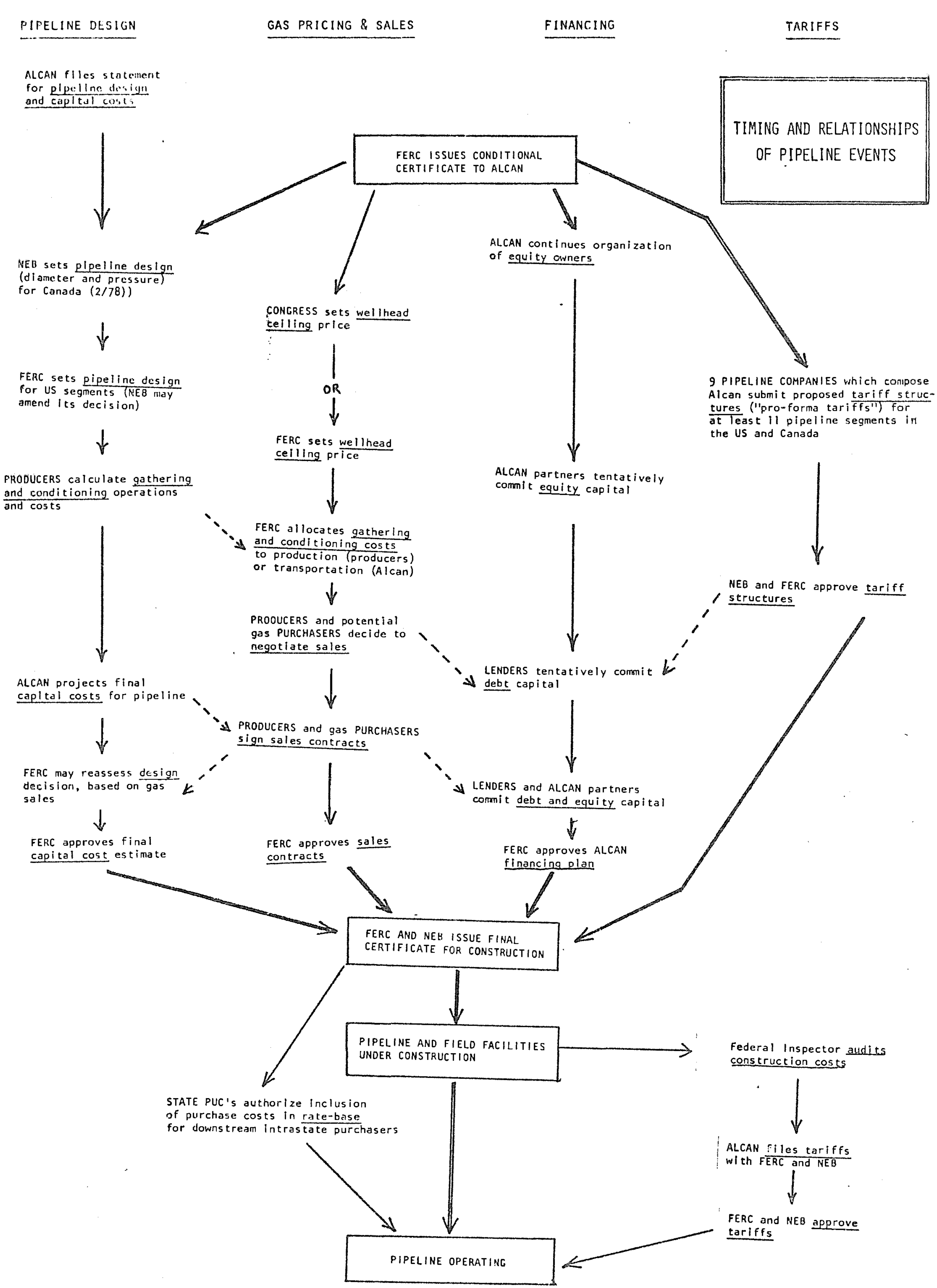
There is, of couse, some potential for chicken-and-egg stalemates to arise, and there are numerous places where difficulties may require that the entire Northwest project "return to go." Further, it is impossible to place these events on a calendar with any degree of certainty. For example, one of the first events (wellhead ceiling price established) may be resolved tomorrow if Congress chooses to act on the gas-pricing amendments now in conference committee. However, if Congress does not act, it could take FERC 18 months or more to conduct the proceedings and establish the ceiling through existing authorities.

This diagram further reveals two principles which should guide State decisions on royalty sales and pipeline financing:

(a) Royalty sales and pipeline financing decisions cannot be made in a vacuum. One cannot determine whether the gasline is a prudent investment without considering the tariff structure, capital costs, and overall economic viability. Likewise, State decisions on these matters will affect a variety of other concerns. For example, sale of royalty gas could affect pipeline throughput and, hence, pipeline design. These sales could also influence the financibility of the project in that equity for pipeline construction will be determined in part by the strength of gas purchasers and their interests in joining pipeline consortiums.

(b) Final commitments for gas sales and pipeline financing by involved parties will probably not take place for a relatively long time. This diagram does not necessarily portray the sequence that *will* occur; instead it portrays the sequence that *would* occur if decision-making is entirely logical and prudent. One can expect the producers to be prudent in committing their gas. One can also expect private investors to be prudent in committing their money. The State must consider both committing its gas and its money; however, pressures have already developed which may make it increasingly difficult for the State to act in a prudent manner.

TIMING AND RELATIONSHIPS OF PIPELINE EVENTS



VI. IMMEDIATE STATE CONCERNS

WHAT SHOULD THE STATE DO WITH ITS ROYALTY SHARE OF PRUDHOE BAY GAS?

A. Timing of Royalty Sales

Of all the gasline events and of all the actors involved, one of the worst "chicken-and-egg" dilemmas is that which confronts the State of Alaska with respect to timing the sale of royalty gas. This is because there are several conflicting demands.

On the one hand, it can be argued that royalty sales should take place relatively late in the sequence of pipeline events when the key questions affecting owner and purchaser interests (such as tariff structures, conditioning cost allocation and final estimates of capital costs) have been resolved. The flow diagram of the previous chapter demonstrates why this is so.

On the other hand, it can be argued that royalty sales should be made rather early in the sequence of pipeline events. This is because pipeline design, which is based on volume throughput assumptions, is a prerequisite to a variety of events (such as calculation of conditioning costs, capital cost estimates, financing, etc.). While producer sales can well be assumed to involve purchasers who intend to carry the gas all the way to the lower states, the destination of State royalty gas is by no means certain. The State has repeatedly declared an intent to find destinations for a large portion of its gas in Alaska--including the use of ethane and heavier hydrocarbons in petrochemical industries.[1] This, naturally, causes a great deal of uncertainty for FERC (which must calculate expected gas throughput when setting a pipeline design), and for Northwest and its investors who have a direct interest in the economic viability of the gasline. It is no surprise that FERC and Northwest are already nudging the State to make some decisions.

There are several approaches to this dilemma:

(1) <u>The State could sell its royalty gas relatively early in the pipeline certification process</u>.

Presumably, this approach would assist FERC and Northwest in pipeline planning; however, it may be very difficult to accomplish.

All purchasers for in-state use (especially petrochemical companies considering an Alaska location) may only be willing to make an early sale commitment if the State bears the risks of how subsequent federal and private decisions affecting the wellhead value will turn out. This would virtually preclude

1/ Gas resources for royalty sales should be viewed in two ways: the sale of dry gas versus liquids. Unless a methanol operation is developed in-state, it is a near certainty that Alaska's royalty methane will flow to the Lower 48, either through direct sale or "in-value" taking in which the producers dispose of royalties for the State. However, use of gas liquids (particularly ethane) in-state for petrochemical development has arisen as a possibility.

the State from being able to find a petrochemical purchaser at an as-yet-unknown "in-value" price.

(2) <u>The State could make an early commitment to remove a portion of its royalties from the gasline at an in-state point, and consummate sales later</u>.

This approach would facilitate FERC's certification of pipeline capacity and design and Northwest's (and investor) financing activities. However, it could also put the State into a box, where it is forced to find a purchaser who is amenable to taking that volume of gas, at the time and at the place it becomes available. If sufficient purchaser interest exists for taking gas under these conditions, "boxing ourselves in" may present no problem. However, if competition is slim or nonexistent, a potential purchaser would have tremendous bargaining strength during State contract negotiations.

(3) <u>The State could sell its gas relatively late in the pipeline certification process</u>.

Under this scenario, the State would, in essence, ignore the desires of FERC and Northwest to establish some degree of certainty with respect to pipeline throughput. There are several reasons why ignoring FERC's interests may not be such a good idea.

(a) FERC has the power to set a tariff structure which could be based on an mcf/mile or zone approach, or which could charge all shippers the full tariff regardless of offtake point. If the latter approach is taken, in-state offtake of royalty gas would be extremely expensive. Nevertheless, FERC might choose to take this approach if it feels it is crucial to the economic viability of the pipeline project. FERC might be especially prompted to do so if it has certified pipeline capacity with the expectation that State royalties will be shipped to the Lower 48, and later discovers that the State plans to sell a substantial volume to a purchaser in Alaska. (It should be noted that this same problem now confronts North Pole refinery, which is being charged the full tariff to Valdez even though it ships its purchased oil only to Fairbanks.)

(b) Under normal circumstances, FERC has the power to approve all off-take of gas once it enters an interstate gas pipeline. Currently, Section 13(b) of the Alaska Natural Gas Transportation Act of 1976 exempts Alaska from FERC's powers; however, Congressional action at any time could eliminate this special treatment.

* * * * * *

Timing of Royalty Sales - Putting it in Perspective:

Before determining which course of action to take with respect to the timing of royalty gas sales, the State should explore the relative importance of its decisions. Considerations might include:

(a) How much additional uncertainty would delayed State sale actions really entail, especially in the context of FERC's responsibility to make throughput assumptions about the as-yet-undeveloped Kaparuk, Lisburne and MacKenzie Delta fields, and about the long-term gas production rate of the Sadlerochit (Prudhoe Unit) reservoir itself? If FERC authorizes construction of a line designed to carry these supplemental reserves as well as the Sadlerochit, despite the risks involved, how then can FERC assert that the State must decide today future offtake plans for its relatively small volume of royalty gas?

(b) While throughput uncertainties do present some economic problems with respect to who pays how much tariff charges, how much of a problem really exists? With respect to physical considerations, how much flexibility will the pipeline and its compressor stations have to carry more or less gas than their design capacity? What problems are caused by a reduction in throughput volume?

B. State Goals for Royalty Sales and Methods to Accomplish Them

Before the State can reasonably make a sale, it should know what it is trying to accomplish and the alternative methods for doing so. For example, the following list portrays some possible goals and methods to accomplish them. Several goals may be compatible in that they can be accomplished by the same sale procedures. However, others may prove to be mutually exclusive.

(1) Maximizing the purchase price - This approach is best accomplished through structuring a competitive sale with no strings attached. This might negate the inclusion of in-state processing restrictions or the inclusion of options for the State to "take-back" gas volumes at a later date.

(2) Encouraging in-state industrial development (including petrochemicals, fertilizers or methanol) - This approach requires

that a sale be limited to in-state bidders, and it may constrain the price the State can expect to receive for its gas. The State could take further actions which would increase State government involvement in the private sector. This might include building intra-state pipelines to carry royalty gas in lieu of the inter-state Northwest pipeline or as laterals from the Northwest line. It could also include State involvement in an exchange of gas components with the producers at Prudhoe Bay or an exchange of gas volumes with Cook Inlet producers.

(3) Providing for present and future needs of Alaskan residential and commercial consumers - This might require small sales of gas initially; however, the majority of the royalty methane would be taken in-value. The State would also need to secure its right to change an in-value taking into an in-kind taking in the future as Alaskan demand grows.

(4) Preserving future options - No sale commitments would be made under this approach. Instead, gas would initially be taken "in-value" with the intent that "in-kind" sales could be made later. Here again, the State may need to take actions to secure its right to take gas in-kind at a later date.

(5) Enhancing the viability of the Northwest Project - Under this approach, the State would sell its gas to a Lower 48 gas purchaser who was already part of, or who could lend additional equity strength to, the pipeline consortium. The sale would be made when the producers sold their gas, if not sooner.

WHAT ROLE SHOULD THE STATE PLAY IN FINANCING THE PROPOSED PIPELINE?

The Northwest proposal: Governor Hammond announced April 15th his proposal for immediate State action concerning the financing of the gasline. Under Hammond's plan, which has been worked out and agreed on by Northwest, the State would create an Authority and give it the power to sell $1 billion dollars in tax-exempt bonds on the condition that Congress change the IRS code to allow the bonds to be tax-exempt. The bonds would be secured by revenues to be generated from the pipeline, and the State would have no obligation to repay them in the event the pipeline was not completed. Instead, the bond-holders would be at risk. Hammond proposed that the Authority have the power to sell the tax-exempt bonds without further legislative approval.

Hammond recommended that the State make no equity commitment at this time, but that the Legislature establish an interim committee to study the possibility of equity participation.

Hammond also released an "Agreement between Alaskan Northwest Natural Gas and the State of Alaska," signed by the Governor and McMillian, which outlines 10 actions Northwest agrees to take regarding State concerns.

Reasons to act now:

1. Northwest needs at the very least a show of support or tentative financial commitment from the State in order to encourage participation from other parties. Northwest officials contend that unless the State acts now, the project's chance of

being financed will diminish significantly.

2. Since the State's regulatory powers over the pipeline are relatively limited, financial participation can provide a vehicle for assuring that an array of State concerns are met. HJR 68, for example, would make State financial participation contingent on a number of conditions, including: the right to in-state takeoff with an mcf-per-mile tariff, a pipeline design capable of carrying liquids, the same advantages for Alaska that other financial participants receive, assurance that Alaskans will have a fair opportunity to provide supplies and services for construction, and allowance for the establishment of a wellhead gas value which, for tax purposes, is equivalent in BTU's to that received for Prudhoe oil. By making its commitment contingent in this manner, the State would be attempting to exert leverage over the federal government as well as Northwest.

3. President Carter and the Congress have said that Alaska, as a major beneficiary of the project, should participate in the financing. Some fear that if Alaska refuses to participate and the project collapses, the federal government will blame the State and take retaliatory action.

4. Pipeline construction will be a significant boost to the State's economy, and therefore the State should do everything it can to assure that the project is built. Northwest officials have testified that the pipeline will mean $20 billion to the State in royalties and taxes over the life of the project,

up to 10,000 short-term jobs, and other indirect economic and employment benefits. A gas pipeline would open up opportunities for in-state processing and petrochemical development.

Reasons not to act now:

1. The State does not have enough information at this point to make an informed judgment about the economics and viability of the project. Until the federal government (either Congress or FERC) resolves the price of Alaska gas and related questions, many uncertainties will remain. If the congressional energy conference committee does not break its long-standing deadlock in the near future, we can expect a one-and-a-half to two-year delay while FERC addresses these issues.

2. It would be desirable to gain additional production history of the field performance--to make sure that recovery of the gas will not harm recovery of the oil--before an irreversible commitment is made to this project.

3. It is possible the gas will be worth more to the State in the future, in 10 or 15 years, than in the near future. This may not be the State's last and only chance for a gas pipeline.

4. Will the short-term construction jobs and related in-migration be worth the additional impact and drain on State services and resources?

5. Any commitment--however tentative and conditional--will make it more difficult for the State to back out in the future, whatever the reason.

6. Some people have questioned whether it is proper for the State to become so deeply involved in activities traditionally conducted by private enterprise.

7. The North Slope producers have been negative on the idea and apparently do not consider debt participation a sound business investment. In addition, FERC and Northwest both maintain State financing is critical to ensuring debt participation by private lenders. Why should the State be the first to get out front, especially in light of the producers' attitudes? Does the reluctance of private financial institutions to commit money indicate questionable project economics?

8. State financial participation in this project would set a precedent for future projects. The President's report lists this as one of the six reasons to explain why federal financial assistance is undesirable.

<u>Substantive versus non-substantive action</u>: Assuming the State chooses to take some kind of action this year, there are two broad possibilities: (1) polite posturing that supports the project in concept but commits no money, and (2) a substantial equity and debt commitment (subject to future legislative approval) that would enhance the project's chances of success.

The first alternative might be followed if the State concluded: (1) that the project may not be economically viable, or (2) that its benefits to the State are of questionable merit, or (3) that it is desirable that the State <u>appear</u> to be doing something so as not to risk federal retaliation.

The second alternative would be appropriate if the State concluded: (1) that its economic and employment benefits will be of great value to the State; (2) that the project is probably economically viable (and, hence, is a sound investment); and (3) State participation is critical for project implementation.

Governor Hammond's proposal seems to fall somewhere between these two broad options. Hammond's plan would be less than a full endorsement (and less than Northwest originally sought from the State) since no equity funds would be committed at this time. From the State's standpoint, a decision not to commit equity now seems prudent in light of the many uncertainties and questions about the project's economic viability.

Congress, the federal government and others, however, may not favor the Hammond-Northwest proposal regarding debt participation. The political aspects must be examined, since the whole scheme is contingent on Congress changing the IRS code. Some problems that may arise:

1. Congress is likely to view this proposal, which would allow the issuance of revenue bonds exempt from federal taxation, as a "backdoor" federal subsidy, which already has been explicitly rejected.

Sen. Henry Jackson's Committee on Energy and Natural Resources said in its report on the President's decision selecting Alcan: "The Committee cautions the administration and the sponsors against taking a backdoor approach to federal financing. We are, of course, aware of the possibility that the Federal Energy Regulatory Commission may be tempted to devise a new type of tariff, or a special type of wellhead price policy, that would in essence be a 'backdoor' or indirect approach with the same practical effect as direct federal participation in project financing. We intend to monitor the project's progress closely and caution that financial 'gimmicks' involving consumer risk-taking via the federal treasury or via special tariffs will not be tolerated by the Congress."

Northwest officials, however, have said they believe the chances are "reasonably good" that Congress will pass the needed federal legislation. Northwest lobbyist Bill Foster cited amendments in the Senate version of Carter's pending energy legislation that would allow the use of tax-exempt bonds for two other energy projects, including a coal gasification project in the midwest, as an example of congressional flexibility on the matter.

2. The Treasury Department historically has opposed tax-exempt bonding as a means of supporting socially desirable investments, pointing out that the government loses several dollars in tax revenues for each dollar of subsidy provided to a public project through this mechanism. The Treasury Department has proposed, as an alternative, that direct subsidies replace the tax-free bonds, but the misgivings of state and local governments about experimenting with new forms of public debt have so far prevented Congress from implementing the Treasury Department's proposal. The Northwest-Hammond plan would be a

move in the opposite direction by expanding the scope and amount of these tax-free bonds.

Northwest lobbyist Foster acknowledged that Treasury probably will oppose the Northwest-Hammond proposal, but he hopes to persuade the Carter Administration to support it nonetheless because of an overriding national interest that the project be built.

3. The Northwest-Administration proposal may generate opposition from state and local governments throughout the United States. Because a bond offering for this project would add to the total offerings of tax-exempt securities, it is possible this offering could raise the interest costs for all other borrowers in the tax-exempt market.

Foster said it is very unlikely the proposed scheme would have any major impact on the overall tax-exempt market for several reasons. First, he said, the tax-exempt bond market absorbs more than $40 billion in new bonds each year, and an additional $1 billion will not have a significant effect. Second, the $1 billion for this project would be issued over a three-year period, reducing the amount in any one year to about $330 million.

Creating a new Authority: One disadvantage of creating a new Authority, as suggested, is that it would shift debate to the details of the Authority's functions and duties and away from the broader policy questions. Also, the Legislature should examine whether another State entity (like the Alaska Industrial Development Authority) already exists that could issue the tax-exempt bonds as proposed.

Further, creating a new Authority of this type might set an undesirable precedent for other industrial development projects. It has been suggested that Alpetco might try to secure financing for its project through such an Authority, if one existed.

HJR 68: Like the Governor's plan, the approach developed by Legislative Research and embodied in HJR 68 also falls somewhere between substantive and non-substantive action. HJR 68 would commit the State to raise about $1.5 billion by pledging the State's royalty gas in the ground as collateral, an approach first suggested by Northwest officials in February. In contrast to the Governor's plan, HJR 68 would make financial participation in any form directly contingent on a number of State concerns, and would require favorable federal action on a number of pricing and regulatory issues as a condition of State participation.

Perceptions of Investors: In examining these two approaches, one must look not only at State concerns but also at how the financial community is likely to react. Given the many uncertainties about the project, investors may be reluctant to loan money based either on anticipated revenues (Governor's plan) or using gas in the ground as collaterial (HJR 68).

Legislative action: As of June 2, neither the House nor the Senate had taken action to establish the Gas Pipeline Financing Authority suggested by Governor Hammond.

The House Special Committee on the Sale of Royalty Oil and Gas made substantial revisions and additions to the Governor's bill (CS HB943) by requiring legislative approval before bonds could be sold and by requiring the authority to submit a "Financial and Alaska Impact Plan" addressing the so-called State concerns.

In the Senate, the Finance Committee modified the Governor's bill by requiring legislative approval before bonds could be sold (CS SB603).

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"Statement of Position Regarding Selection of Pipe for Whitehorse, Yukon to Caroline, Alberta Segment of the Foothills Pipeline", Canadian National Energy Board, 2/78

3/27/78 letter from ARCO to Federal Energy Regulatory Commission

3/9/78 letter from SOHIO to Federal Energy Regulatory Commission

Appendix II Description of Basic Principles of Oil and Gas Processing and a Description of the Prudhoe Bay Oil Field Facilities; Alyeska (located in Assistant Attorney General Bob Maynard's office)

ROYALTY GAS

"State of Alaska Utilization of Royalty Gas"; Bonner & Moore; 1/78

"Utilization of Alaska Royalty Gas & Liquids"; Galliett & Silides; 1/78

MISCELLANEOUS

"Regulatory Treatment of Natural Gas Liquids"; Bob Loeffler; (prepared for the State of Alaska); 3/78

The two documents which set forth the ownership and operating procedures of the Prudhoe Bay Unit are:

(1) Unit Agreement

(2) Operating Plan (2 volumes)