

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 86/2

481 SCOMM14: JOINT GAS PIPELINE COMM. (FINANCING) 1979-80

FRAGILITY OF CANADIAN FINANCING

We also were requested to examine the possibility that the Canadian side financing is relatively uncertain, or "fragile", as opposed to the more common belief that Canadian financing will be no problem. It is difficult to come up with a precise response as to how solid Canadian financing is because the consortium has not yet gone to the financial markets with a firm proposal and tried to finance it. However, we find no factual basis for the rumors that financing may be more difficult in Canada than is now supposed. While the final terms and conditions of any financing package cannot be determined as yet, it appears that they should be favorable to Foothills. More importantly, when one examines the financial strength behind the Canadian side of the line, it becomes increasingly clear that their financing prospects should be fairly solid. The Canadian portion of the line is backed by the three largest Canadian pipelines, the State Oil Company of Canada, the largest private oil company of Canada, the British Columbia Government (and its cash-rich Resources Investment Corporation), and the Alberta Government which is seeking desperately to find ways of investing its Heritage Fund. Moreover, there is only significant risk in the Yukon segment of the line which constitutes slightly less than \$2 billion of the \$5.5 billion Canadian capital cost segment. When one adds to these fundamentals the realization that some of the Canadian line would be financed during the pre-build period, while other parts would be financed afterwards, thus spreading out the burden on the financial markets, we can only conclude that the "fragility rumor" appears unfounded.

U.S. FINANCING DEVELOPMENTS

Exxon's recent proposal to the United States Government does little to clarify the financing outlook for the pipeline. Exxon's proposal, ostensibly made on its own behalf, assumes participation by Arco and Standard Oil of Ohio. Both of these companies have made preliminary comments indicating approval of the general thrust of Exxon's concept. Basically, the Exxon proposal involved:

1. That the three major North Slope natural gas producers jointly provide 40% of the equity and 40% of the debt for the Alaska segment of the line. Exxon's proposed investment levels (as publicly reported) are based on a cost estimate for the Alaska segment of \$10 billion (presumably including both the pipeline and conditioning plant).

2. That in return for this investment, the Federal Government allow the treatment and conditioning costs, plus a rate of return to be included in the pipeline tariff, rather than absorbed by the oil companies at the wellhead.

FERC, of course, has been moving strongly in the direction of imposing treatment and conditioning costs upon the oil companies. It has been the FERC view that the approximately \$2.00 per mcf price granted for North Slope natural gas by the Natural Gas Policy Act of 1978 is intended to include such costs. A final FERC rulemaking on this issue was scheduled to be complete this month. However, the Department of Energy has lead federal responsibility on technical issues relating to the treatment and conditioning of the natural gas, since FERC has defined it as essentially a production and gathering related activity. DOE is on the side of the oil companies in this respect, and Energy Secretary Charles Duncan has written a letter to FERC Chairman Charles Curtis requesting that the Commission re-examine its preliminary decision imposing treatment and conditioning costs upon the producers and allow such costs to be added on to the pipeline tariff.

If FERC is to reverse its decision with respect to treatment and conditioning costs at this late date, it seems likely that some relatively clear signal from the White House on the subject will be required. Also, the Exxon proposal seems designed to trigger precisely such White House action, since White House intervention will be required in any event to allow producer investment of the sort proposed by the company. It seems clear that Exxon has preempted the Federal Government on the question of producer financing by getting its demands on the table first. The result is that the White House and the Justice Department must now formulate some device whereby the language of the President's Decision forbidding oil company investment in the project can be sidestepped. Further, Exxon is placing the onus of a refusal to allow treatment and conditioning costs in the pipeline tariff on the Federal Government. They have turned what was previously considered a foregone conclusion into a negotiable point within their proposal, and it would seem that they are virtually forcing the Federal Government to either negotiate or to concede that private financing cannot work. At this juncture, it is difficult to predict whether FERC will stay with its original proposal to impose such costs upon the oil companies. However, one option is to grant some form of extraordinary relief as provided for in the Natural Gas Policy Act. It can, of course, be expected that there will be great opposition to any such proposal from consumer groups and FERC staff. Seen in the context of an upcoming election, it is difficult to predict what choice the Carter Administration might make between having producer financing available and enduring the wrath of consumer and liberal advocates.

The Exxon proposal would seem to be a useful blueprint for the type of policy that could be advantageous to the State. In short, Exxon's proposal seems to insure that if they finance, they will finance on their terms and that financing will be available for only a discrete portion of the project. If Alaska waits until all other participants have agreed to financing shares and proportions, the State may be pressured to join the cost overrun pool where obligations are theoretically open-ended and where management rights, equity ownership, and rates of return are relatively uncertain or absent. There is, of course, nothing magic about the Exxon proposal; it is something that the Alaska Legislature and the Administration could duplicate with relative ease.

The critical time for financing the project and with respect to Alaska participation continues to be the Spring of 1980. During this period, Northwest will be investigating financing sources with a view to obtaining FERC financing approval by the Summer of 1980. It also coincides with the period that the State Legislature is in session; consequently, great pressure upon the State can be expected from the period January - May 1980. Jack Rhett's rhetoric in our meeting of October 17 regarding his great concern over the State of Alaska's possible obstructionist role, his view that financial participation is required (not only technically but to provide an incentive for the State not to obstruct the project), and his flat-out statement that pressure might be brought upon the State if they do not finance, all tend to support the view that the first half of 1980 will be a critical period.

SUMMARY AND CONCLUSION

While the maneuvering on the pipeline issue remains at a high level, it remains very questionable whether this project will succeed during 1980. A possible alternative scenario could involve the period June 1980 - January 1981, during which it is very possible that Carter will be a "lame duck" President. To the extent that he uses this period to pay off old political friends, it could be a very rough period for the State of Alaska if the President attempts to move the project forward on the financing front by coercive measures against Alaska and the producers. This scenario is, of course, predicated upon the assumption that Alaska does not make progress with respect to financing during the Spring of 1980 (an arguable point) and that Northwest fails to achieve the requisite levels

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of financing by the Summer of 1980 (a much less arguable point). On balance, however, it still seems most likely that renewed activity and a possible reformulation of the project will occur after the 1980 elections.



JOSEPH M. CHOMSKI, ESQ.

RICHARD G. HAGGART
Energy Consultant

JMC/RGH:brk

Joint Gas Pipeline Committee
Alaska State Legislature

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EX-OFFICIO MEMBERS

MR. ROBERT LERESCHE MR. JACK BACHMAN



727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

November 20, 1979

TO: Rep. Sam Cotten
FROM: Mary Halloran ^{HH}
Research Analyst

As per your request, this paper reviews the projected national net economic benefits from the gas pipeline project, comparing the expected federal benefits to the estimated state benefits.

Two reports have been published on this subject: a May, 1979 ICF report, commissioned by the Federal Energy Regulatory Commission; and short comments filed on June 22, 1979, by EXXON in response to the ICF report.

ICF REVIEW

The ICF concluded that the National Net Economic Benefit (NNEB) would be \$14.9 billion, distributed as follows:

Consumers (fuel cost savings)	\$2.7 billion	(18%)
Producers (extra profits)	3.7	(25%)
Alaska (taxes and royalties)	4.7	(32%)
Federal Government (taxes)	3.5	(23%)
Pipelines (tax credit)	0.2	(2%)
	<u>\$14.9 billion</u>	

The ICF conclusions are based on the following assumptions: the figures are in mid-1979 dollars; field life is 25 years; 6% discount rate applies; conditioning costs are paid by the producers.

If the discount rate used is changed from 6% to 10%, then the benefits would decrease as follows:

Consumers	\$0.6 billion (mid-79 dollars)
Producers	2.2
Alaska	2.9
Federal Government	2.2
Pipelines	0.3
	<u>\$ 8.1 billion</u>

Rep. Cotten
November 20, 1979
Page Two

Enclosed is a summary page from the ICF report giving various NNEB scenarios under both 6% and 10% discount rates.

EXXON COMMENTS

The basic thrust of the ICF study was to "prove" that conditioning costs had to be shouldered by the gas producers in order for the consumers to receive any benefits from gas pipeline construction. EXXON responded to the ICF study with comments compiled by Foster Associates. They examined the net economic benefits with purchasers, not producers, bearing conditioning costs. The assumptions which differed in the EXXON-Foster work were the following: Alaska gas replaces distillate fuel oil, not residual fuel oil, and must be valued accordingly; thus, the cost of distillate fuel oil and real world escalation trends have to be used to draw comparisons; and purchasers must bear some, if not all, the conditioning costs.

The Foster work concluded that the net national economic benefit is much higher than that projected in the ICF study -- \$27.2 billion, in fact. The distribution of that benefit would be as follows:

Consumers	\$10.6
Producers	5.6
Alaska	5.2
Federal Government	5.4
Pipeline	.4

Under the EXXON scenario, the federal government benefits more than the State of Alaska from the gas pipeline project.

Neither the EXXON comments nor the ICF report were meant to be definitive; in fact, both are written largely to back specific stances on who should bear the conditioning costs. Until the question of conditioning costs responsibility is resolved, it will be difficult to determine which, the federal or the state government, will receive the larger share of tax returns from the project. In addition, the state's share will also depend on the final resolution of Amerada Hess v. State. If the producers are responsible for the conditioning costs and if they are allowed to subtract those costs from the wellhead value before calculating state severance taxes, then the monies the state receives could be significantly less from those otherwise projected.

Rep. Cotten
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Page Three

In any case, it is not at all clear that the State's benefits will be significantly greater than the federal government's benefits from the project.

cc: Members of the Joint Gas Pipeline Committee

TABLE V-1
DISTRIBUTION OF NNEB FOR SELECTED SCENARIOS
(mid-1979 dollars)

Scenario	Net Benefits					Total NNEB
	Domestic Producer	Alaska	Federal Gov't.	Consumer	Pipeline Owners	
<u>6 Percent Discount Rate</u>						
Base Case	3.7	4.7	3.5	2.7	0.2	14.9
High Cost	3.7	4.7	3.5	-1.9	0.4	10.4
Base Costs, Medium Oil Price Escalation	3.7	4.7	3.5	10.1	0.2	22.3
Base Costs, Residual Oil Value, Low Escalation	3.7	4.7	3.5	-0.4	0.2	11.8
Base Costs, 3.2 Bcf/d Flow	5.2	6.4	5.1	5.4	0.2	22.3
Base Case With Gas Conditioning Charges	5.6	5.2	5.4	-1.7	0.4	14.8
<u>10 Percent Discount Rate</u>						
Base Case	2.2	2.9	2.2	0.6	0.3	8.1
High Cost	2.2	2.9	2.2	-2.5	0.4	5.2
Base Costs, Medium Oil Price Escalation	2.2	2.9	2.2	4.6	0.3	12.2
Base Costs, Residual Oil Value, Low Escalation	2.2	2.9	2.2	-1.3	0.3	6.3
Base Costs, 3.2 Bcf/d Flow	3.1	3.9	3.1	2.0	0.3	12.5
Base Case With Gas Conditioning Charges	3.4	3.1	3.3	-2.2	0.4	8.0

ICF INCORPORATED

AGO 532949

Joint Gas Pipeline Committee
Alaska State Legislature

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REP. JOE HAYZS

REP. CHARLES PARR

EX-OFFICIO MEMBERS

MR. ROBERT LERESCHE MR. JACK BACHMAN



727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
19071 278-4340

November 26, 1979

TO: Rep. Sam Cotten
FROM: Mary Halloran, ^{WR} Research Analyst

As per your request, this paper reviews the provisions for protecting the Northwest Alaska gas pipeline from unexpected and discriminatory taxation by Canadian provincial and federal governments. In brief, this issue was raised during the early pipeline proceedings, and the two governments, U.S. and Canadian, acted to prevent the possibility of discriminatory taxation.

First, provisions were made to ensure fair Canadian taxation in the Transit Pipeline Treaty which was ratified by the U.S. Senate. Second, these provisions were reiterated in the U.S.-Canadian Agreement on Principles which became part of the September, 1977, President's Decision, also later ratified by the U.S. Congress. Third, the Canadian Federal Government also obtained public endorsements of the provisions from the three provinces of British Columbia, Alberta, and Saskatchewan. These statements are annexed to the U.S.-Canadian Agreement. Finally, the Canadian House of Commons passed C-25, the Northern Pipeline Act, which includes both the U.S.-Canadian Agreement and the provinces' public endorsements of the taxing provisions of the Pipeline Treaty. Thus, the Canadian taxing procedures have been established through Treaty, International Agreement, and specific legislation.

A special provision was negotiated regarding ad valorem tax in the Yukon Territory, as no similar pipelines exist there. The Yukon Territory taxing structure is similar to Alaska's and will change only if the State of Alaska changes its property tax structure.

cc: Members of the Joint Gas Pipeline Committee

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Joint Gas Pipeline Committee Alaska State Legislature

need to keep?

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REP. TERRY GARDINER
REP. CHARLES PARR



POUCH V
JUNEAU, ALASKA 99811
(907) 455-3779

March 18, 1980

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE MR. JACK BACKMAN

COMMITTEE REPORT

At its March 12, 1980, meeting, the Joint Gas Pipeline Committee heard a presentation by Earth Resources Company of Alaska (ERCA). ERCA proposes the State establish a tax exempt bonding authority for Prudhoe Bay gas liquids. According to ERCA representatives, the state authority would provide tax exempt financing, lowered cost of gas to the transportation system, and natural gas liquids for instate use. The proposal included draft legislation for the authority.

The Committee agreed to have the draft legislation prepared for introduction to the Legislature.

In further action, the Committee discussed a proposed budget for studies and continued activities by the Joint Committee. The Committee agreed to request a budget appropriation of \$950,000 which would cover a financial consultant; engineering/design work on the gas conditioning plant and its location; liquids line study; economic feasibility of petrochemical industry study; options/uses and marketability of royalty gas study; study of federal control, pricing and tariffs and their impact on Alaska gas and gas liquids use; and staff for the Joint Gas Pipeline Committee and Governors-Mayors Task Force, travel and contingency.

Joint Gas Pipeline Committee Alaska State Legislature

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REP. JOE HAYES

REP. BILL MILES
CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR



POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE MR. JACK BACKMAN

March 31, 1980

The Joint Gas Pipeline Committee is holding an oversight hearing on the status of the contract between the State of Alaska and Alaska Petrochemical Company. The hearing will begin at 2:00 p.m., April 14, in Room 522 (Senate Finance), Capitol Building, Juneau.

AGO 532952 4

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Joint Gas Pipeline Committee Alaska State Legislature

SEN. MIKE COLLETTA
CO-CHAIRMAN

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REP. BILL MILES
CO-CHAIRMAN

REP. CHAT CHATTERTON

REP. TERRY GARDINER

REP. CHARLES PARR



EX-OFFICIO MEMBERS

MR. ROBERT LERESCHE MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

April 10, 1980

MEETING NOTICE

The Joint Gas Pipeline Committee oversight hearing on the contract between the State of Alaska and the Alaska Petrochemical Company has been rescheduled for 2 p.m., Monday, April 28. The meeting will be held in Senate Finance, Room 522, Capitol Building, Juneau.

AGO 532953

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PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.

APPENDIX D

PUBLIC LAW 94-586—OCT. 22, 1976

90 STAT. 2903

Public Law 94-586
94th Congress

An Act

To expedite a decision on the delivery of Alaska natural gas to United States markets, and for other purposes.

Oct. 22, 1976
[S. 3521]

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Alaska Natural
Gas
Transportation
Act of 1976.
15 USC 719 note.

SHORT TITLE

SECTION 1. This Act may be cited as the "Alaska Natural Gas Transportation Act of 1976".

CONGRESSIONAL FINDINGS

SEC. 2. The Congress finds and declares that—

15 USC 719.

(1) a natural gas supply shortage exists in the contiguous States of the United States;

(2) large reserves of natural gas in the State of Alaska could help significantly to alleviate this supply shortage;

(3) the expeditious construction of a viable natural gas transportation system for delivery of Alaska natural gas to United States markets is in the national interest; and

(4) the determinations whether to authorize a transportation system for delivery of Alaska natural gas to the contiguous States and, if so, which system to select, involve questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact, and therefore should appropriately be addressed by the Congress and the President in addition to those Federal officers and agencies assigned functions under law pertaining to the selection, construction, and initial operation of such a system.

STATEMENT OF PURPOSE

SEC. 3. The purpose of this Act is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous States for construction and initial operation by providing for the participation of the President and the Congress in the selection process, and, if such a system is approved under this Act, to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this Act, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions. To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitation of judicial review of actions of Federal officers or agencies taken pursuant thereto.

15 USC 719a.

90 STAT. 2904

PUBLIC LAW 94-386—OCT. 22, 1976

DEFINITIONS

15 USC 719b.

SEC. 4. As used in this Act:

(1) the term "Alaska natural gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

(2) the term "Commission" means the Federal Power Commission;

(3) the term "Secretary" means the Secretary of the Interior;

(4) the term "provision of law" means any provision of a Federal statute or rule, regulation, or order issued thereunder; and

(5) the term "approved transportation system" means the system for the transportation of Alaska natural gas designated by the President pursuant to section 7(a) or 8(b) and approved by joint resolution of the Congress pursuant to section 8.

FEDERAL POWER COMMISSION REVIEWS AND REPORTS

Proceedings,
suspension.
15 USC 719c.
15 USC 717w.

SEC. 5. (a) (1) Notwithstanding any provision of the Natural Gas Act or any other provision of law, the Commission shall suspend all proceedings pending before the Commission on the date of enactment of this Act relating to a system for the transportation of Alaska natural gas as soon as the Commission determines to be practicable after such date, and the Commission may refuse to act on any application, amendment thereto, or other requests for action under the Natural Gas Act relating to a system for the transportation of Alaska natural gas until such time as (A) a decision of the President designating such a system for approval takes effect pursuant to section 8, (B) no such decision takes effect pursuant to section 8, or (C) the President decides not to designate such a system for approval under section 8 and so advises the Congress pursuant to section 7.

(2) In the event a decision of the President designating such a system takes effect pursuant to this Act, the Commission shall forthwith vacate proceedings suspended under paragraph (1) and, pursuant to section 9 and in accordance with the President's decision, issue a certificate of public convenience and necessity respecting such system.

(3) In the event such a decision of the President does not take effect pursuant to this Act or the President decides not to designate such a system and so advises the Congress pursuant to section 7, the suspension provided for in paragraph (1) of this subsection shall be removed.

Recommendation,
submission,
to President.

(b) (1) The Commission shall review all applications for the issuance of a certificate of public convenience and necessity relating to the transportation of Alaska natural gas pending on the date of enactment of this Act, and any amendments thereto which are timely made, and after consideration of any alternative transportation system which the Commission determines to be reasonable, submit to the President not later than May 1, 1977, a recommendation concerning the selection of such a transportation system. Such recommendation may be in the form of a proposed certificate of public convenience and necessity, or in such other form as the Commission determines to be appropriate, or may recommend that no decision respecting the selection of such a transportation system be made at this time or pursuant to this Act. Any recommendation that the President approve a particular transportation system shall (A) include a description of the nature and route of the system, (B) designate

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SUMMARY OF TECHNICAL REPORT ON PRODUCERS' PROPOSED
PLAN OF OPERATION OF THE PRUDHOE BAY FIELD

On August 18, 1976, a draft of the proposed Prudhoe Bay Unit Agreement was presented by the producers to the Alaska Department of Natural Resources. The draft included a summary of the producers' recommended plan of operations for the Prudhoe Bay Field. Subsequently, the producers prepared and submitted to the Alaskan authorities a technical report on the recommended operating plan. The report (Exhibit ALA-33) sets forth the results of the comprehensive technical studies conducted independently over the past several years by the major producers to develop long range operating plans for the Field. The following is a summary of that report.

According to the report, oil production is planned to commence in mid-1977 at a rate of 600,000 B/D, increasing to about 1,200,000 B/D by the end of 1977. Completion in 1978 or 1979 of field facilities necessary for the purpose will permit a further planned production increase to about 1,500,000 B/D when pipeline capacity is available. Such rate of oil production can be maintained for about 8 years by additional development drilling.

Until a gas pipeline and gas conditioning plant are approved and constructed, currently estimated to be 4½ to 5 years after the start of oil production, produced gas in excess of fuel requirements (1.8 to 2.0 Bcf/d) will be injected into the gas cap without adversely affecting ultimate oil recovery. The gas conditioning plant will be needed to bring the gas to pipeline quality including CO₂ removal, extraction of gas liquids for hydrocarbon dew point control, dehydration, and compression and cooling to pipeline pressure and temperature. Preliminary estimates made several years ago indicate that the plant will require 4 to 6 years to design, fabricate and construct, and will cost about \$1 billion (1976 costs).

Once the necessary pipeline and conditioning plant are in place, gas pipeline deliveries of at least 2.0 Bcf/D will commence. Delivery at this level will require gas production of 2.7 to 2.8 Bcf/D to allow for fuel requirements, shrinkage and CO₂ removal. The 2.0 Bcf/D planned rate is a conservative volume which can clearly be supported by the reservoir, and initial gas pipeline deliveries of up to 2.5 Bcf/D may be justified, without affecting ultimate oil recovery.

Planned pipeline deliveries will substantially increase domestic energy supplies. For instance, through year 2,000, pipeline deliveries of 2.0 Bcf/D, beginning 5 years after the start of oil production, add the energy equivalent of 2 billion barrels of oil to the nation's energy supply. In addition, such gas deliveries reduce fuel consumption, eliminate unnecessary costs for compression, injection, and "double production" of gas, and provide a measure of correlative rights protection for the Oil Rim and Gas Cap participating area owners.

In the Main Area Sadlerochit reservoir, the natural recovery mechanism of the field will permit oil recovery predicted in the range of from 32% to 35% of the original oil in place. The current operating plan calls for the injection of produced water into the Sadlerochit when volumes become significant, increasing recovery to 33% to 36%. Studies indicate further potential for increasing ultimate oil recovery to a level of 39% to 40% of original oil in place by implementing a properly designed source water injection program within about 5 to 9 years after the start of oil production. Two or more years of production performance history and testing data will be necessary to confirm the additional recovery potential before the final decision is made to commit approximately \$1 billion for source water injection facilities. It is estimated that oil recovery will be achieved over a period of 25 to 30 years. Ultimate gas recovery, expected to be in the range of 75% to 80% of total gas-in-place, will be recovered over a period of about 35 years.

It is expected that significant volumes of gas cap gas will be produced through oil wells. If this gas is not delivered to a pipeline, it will be necessary to reinject an estimated 15 to 20 Tcf of gas into the gas cap. Although the return of such gas is not detrimental to reservoir performance, compression and injection of this volume would require about 600 to 800 Bcf of fuel gas, or the energy equivalent of more than 100 million barrels of oil. Moreover, the extraction of liquids required to condition the gas for pipeline delivery will provide for an additional 10 million barrels per year of gas liquids. All liquids extracted will be used without waste; either to displace fuel gas or be transported through the oil pipeline with the crude oil and condensate. 1/

1/ A gas cap gas condensate yield of about 35 barrels per MMcf of separator outlet gas is expected initially from the separator facilities.

XVII

SUMMARY

The extensive discussions above give some of the flavor of the public debate now underway as to which pipeline applicant should be certificated and what degree of consumer or taxpayer involvement is warranted. The full measure of interest and controversy also was displayed in the plethora of Wrap-up Briefs and Position Briefs filed by all the applicants (including affiliates), intervening states, natural gas transmission companies, distribution companies, Conservation Intervenor and Staff.

As has been stated supra, Staff, charged directly with representing the public interest, supports the Arctic Gas project (without the western leg) as vastly superior. The Conservation Intervenor support Alcan, on environmental grounds. Of those states which support a particular project in their Final Briefs, the majority choose Arctic Gas. New York, Wisconsin and California voice support for the Arctic Gas system. 1/ It is significant, in fact, that the most populous states in the east and west, and one of the largest in the midwest all see their interests best served by the Arctic Gas project, if any Alaskan gas delivery system is built. California's preference is predicated in part not on the economics of these proposals, which it finds marginal, but on the ability of Arctic Gas to move the additional supplies it expects to come from the far north. Alaska is the only state which supports El Paso, based on the perceived environmental, socio-economic and reliability benefits. Interestingly, Washington and Oregon do not state a preference for any project, but, like California, state their support for Arctic Gas with a western leg (if Arctic Gas is certificated). Utah supports an overland route with a western leg. Arizona, while not preferring any system, wants assurances that it will have direct access to, and an equitable share of, Alaskan gas. This argument seeking to allocate gas supplies is premature in that no producer sales contracts have been entered.

Of those gas transmission and distribution companies which support a particular project, the majority choose Arctic Gas. Algonquin Gas Transmission Company (New England), Michigan Consolidated Gas Company (Michigan), Wisconsin Gas Company (Wisconsin) and

1/ The State of Wisconsin petitioned to intervene in January, 1977, and the Commission approved intervention by order dated January 25, 1977.

the New York Gas Group (New York) favor Arctic Gas. Intermountain Gas Company (Idaho) supports Alcan, on the basis of environment and reliability. Tennessee Gas Pipeline Company and Southern Natural Gas Co. prefer El Paso, but their views can be given little weight. As is conceded in the briefs, these companies have signed agreements with Alaska to purchase royalty gas, and thus were contractually bound by Alaska to support El Paso. Cascade Natural Gas Corporation (Washington and Oregon) and Washington Water Power Company (Washington) only voice their support for a western leg and, of course, all of the many major transmission and distribution companies sponsoring Arctic Gas support their project.

In a sense, there is a consensus on the part of the Commission Staff, the most popular consuming states taking an active interest, and an array of pipelines and distributors serving huge sections of the country that if any pipeline applicant must be chosen now, their best interests would be served by choosing Arctic Gas. The evidence in this record clearly supports that conclusion. There is no need to summarize here the findings made in the individual sections above. The Arctic Gas application is superior in almost every significant aspect when compared to El Paso. Certification of its proposal, subject to appropriate conditions, will bring more energy to market cheaper and more reliably than El Paso and will do so in an environmentally acceptable manner. It is found that Arctic Gas' prime route should be certificated, including both western and eastern legs.

El Paso, too, has a viable plan which technically can be built in an environmentally sound manner and which can deliver natural gas to all U.S. markets. While its certification is less desirable because of the reasons discussed above, nonetheless, it could be certificated if it were not for the clearly superior Arctic Gas application. Thus, if Arctic Gas is unable to accept a certificate, this record supports findings that El Paso's proposal, as required to be modified by the findings above, would also meet the present and future public convenience and necessity.

No finding from this record supports even the possibility that a grant of authority to Alcan can be made. No grant could include Westcoast, but its sponsors state that exclusion of Westcoast would render Alcan's financial plan inoperative. The allocation procedures supported in the record by AGTL are now inoperative according to AGTL, and this means no meaningful costing of facilities can be made from this record. Furthermore, Alcan's present design is clearly neither efficient nor economic since the pipeline is undersized. The suggested three years construction schedule to be completed by 1981, which Alcan argues is one of its

prime strengths, cannot occur. Moreover, its arguments as to how it can be financed in separate time frames from Maple Leaf, also critical to its proposal, requires intricate timing that is totally unsupported by hard evidence. As presently proposed, even with Alcan's willingness to build anything anyone wants (as long as it does not oust Westcoast and AGTL from their Maple Leaf project), there is not enough left of its original proposal to serve as a basis for granting its application.

Nahum Litt

Nahum Litt
Presiding Administrative Law Judge

PROPOSED LEGISLATION

A. Section 13 of the Alaska Natural Gas Act of 1976

The State of Alaska has entered into contracts for the interstate sale of its royalty gas which include provisions permitting the State to subsequently withdraw the gas from the interstate market for use within the State. These withdrawal provisions are sanctioned by Section 13(b) of the Alaska Natural Gas Act of 1976.

However, as discussed in the Jurisdiction and Financing sections of this Initial Decision, substantial difficulties arise from the State's asserted right to commit its gas to interstate use with one hand and take it back with the other. The mere prospect of withdrawal imperils the financeability of an Alaskan gas project; actual withdrawal would idle downstream facilities and in turn produce adverse cost impacts.

Moreover, when the Section 13(b) withdrawal provision is coupled with the Act's "equal access" provision, ^{1/} it becomes readily apparent that the statute in its present form could operate to confer a substantial indirect subsidy to the State. Assuming that the project could be financed and completed, that Alaska's interstate customers (El Paso Natural, Tenneco Alaskan, and Southern) participated in the equity financing with consumer guarantees, and that Alaska thereafter found an intrastate use for its royalty gas, the consumers of the three customer companies would have risked their dollars to help finance the project, only to see consumers in Alaska reap the reward.

For the reasons stated herein, the Presiding Judge respectfully suggests that the Commission, in its recommendation to the President, give consideration to the desirability of amending the Alaska Natural Gas Act of 1976 to delete therefrom Sections 13(a) and 13(b). Absent deletions of these two provisions, direct and total U.S. government guarantees would appear to be the only feasible method of financing.

^{1/} Section 13(a) of the 1976 Alaska Natural Gas Act would deny the Commission the power to limit access to the transportation system to shippers participating fairly in its equity financing. It is questionable whether the proposal to finance an Alaskan project with consumer guarantees is possible in the face of this statutory provision.

B. Other

Unlike the preceding extended discussion respecting Section 13 of the Alaska Natural Gas Transportation Act of 1976, the need for the following legislative recommendations has been adequately addressed in the Financing and Potpourri sections, supra:

1. LNG Ships

To insure effective regulatory control of rates and operations of the El Paso tanker fleet, explicit statutory jurisdiction should be conferred on the Commission.

2. Tracking

Full and timely recovery from ultimate consumers of all appropriate costs in connection with an Alaskan transportation project, during both the construction and operations periods, requires implementation by Federal legislation. The Commission should not have the power to suspend such flow through of costs, but the right to review all such costs at all times, with the power to order refunds where appropriate, should be preserved.

3. Federal Financial Participation

The Treasury Department should be granted statutory authority necessary and appropriate to accomplish whatever Federal participation in the Alaska gas project financing is ultimately determined to be required in the public interest.

Armed personnel.

The crew was identified as: Capt. Donald W. Deeter, 29, pilot, of Fillmore, Calif.; CWO Ralph G. Battle, 38, copilot, Miami, and Spec. 4 Paul E. Jones, crew chief, St. Cloud, Fla.

Passengers, all stationed at Ft. Richardson, were identified as: Lt. Col. William I. Barrett Jr., Beckley, W. Va., commander of the 1st Battalion, 43rd Air Defense Artillery; Lt. Col. John S. Edge, 42, assistant post commander, Americus, Ga.; Maj. James W. Nelson, 38, operations officer of the 1st Battalion, Greenville, Ala. and Major Melvin J. Swiney, Tacoma, Wash.

confirmed that the strike had ended, but declined to discuss details of the settlement.

The strike, which began Feb. 2, cost Sea-Land an estimated \$1.38 million. While some company services were disrupted, supervisory personnel performed many delivery functions. At one point Teamster pickets followed Sea-Land trucks around to picket unloading operations.

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measure authored by Sen. Chancy Croft, D-Anchorage, establishing another commission to conduct more studies, this round to be completed by January of 1978.

Lethin's plan was met with solid support by Matanuska Valley residents who testified in Palmer Friday night. But response from the 26 Anchorage residents who testified Saturday and Sunday was mixed. Hearings will move to Fairbanks next weekend.

AS EXPECTED, however, testimony took a 180-degree turn from that heard in Juneau last week, where most of those who testified sidestepped the bills under consideration and relied upon emotional appeals to keep the capital in Juneau.

Among those testifying Sunday was Anchorage attorney Gale McCarrey, who suggested that capital design should be submitted to international bid.

"I'm sure lots of architects would like their names ascribed to the new Alaska capital," McCarrey testified.

McCARREY ALSO said he didn't think the new capital would cost "too much money."

"IT PROBABLY WILL BE more intriguing to hear the comments in Fairbanks," said Bradley, who will chair the hearings there.

Bradley said he was disappointed there wasn't a "higher incidence of man-of-the-street comment in Anchorage."

"I would have liked to have seen 200 people and only 20 architects or planners," he said.

MEANWHILE, A study was released estimating that it would cost about \$214,000 a month to set up temporary government offices near Willow. The study, prepared for Lethin, did not take into consideration the cost of housing.

Several Anchorage engineering, architectural and modular construction firms were involved in the preparation of the study. It was based upon creating office space for the governor, lieutenant governor, and the legislature.

A total of 80,000 square feet of office space would be provided.

State at odds with gas plans

By G. MICHAEL HARMON

Associated Press Writer

JUNEAU — Oil industry proposals for the earliest possible delivery of massive amounts of Prudhoe Bay natural gas to the lower 48 states have been quietly but firmly squashed by the State of Alaska.

The dispute, which may place Alaska interests in direct conflict with national energy demands, centers on major differences between state and oil industry officials over how best to manage the North Slope reservoir's 19.5 billion barrels of oil and 26.5 trillion cubic feet of natural gas.

Oil industry officials say their plan "provides for expeditious and economic development of the total energy resources at Prudhoe Bay consistent with good oil and gas conservation practices."

In challenging the proposal, however, state officials say the operators' plan may be motivated more by a "disincentive to produce oil because they have a surplus on the West Coast and an incentive to produce gas because it's very dear right now."

At the center of the intense but unpublicized debate are two conflicting documents obtained by The Associated Press—the industry's "operating plan" for exploiting Prudhoe Bay reserves and a sophisticated state-financed computer "prediction of reser-

voir fluid recovery" from the field.

In its proposed operating plan, the industry has asked the state to guarantee the delivery of at least two billion cubic feet a day of gas by mid-1982, about five years after this summer's planned start-up of the trans-Alaska oil pipeline and the earliest possible date projected by the oilmen for completion of a natural gas pipeline and conditioning plant.

But state officials, who have been involved in confidential negotiations with the Prudhoe Bay producers over the operating plan for more than three months, have steadfastly rejected the industry management scheme on the premise that it violates Alaska's tough conservation statute for the maximum production of both oil and gas.

In its computer projection, the state contends that the delivery of two billion cubic feet a day of natural gas under the industry plan could cause the loss of as much as 1.6 billion barrels of oil, a significant figure in light of the acknowledgement by both sides that under the best of circumstances ultimate oil recovery from the field will total a maximum of only 40 per cent of the oil in place.

In an effort at compromise, the state says it could allow the gas delivery rate proposed by the oilmen if they will commit themselves to a massive water injection plan at the North Slope field.

All-Alaska gas line risks

Page 2

While acknowledging that the injection of water from the Arctic Ocean could help offset the loss of field pressure from early, large-volume production of gas, industry officials say they cannot and will not commit themselves to the \$1 billion-plus cost of a source water injection project without several years of field history.

In contrast, the industry plan says field history is not needed for the state to guarantee early, massive gas offtake rates, an inconsistency noted by the state in rejecting the operating proposal.

The operating plan submitted by majority owners of North Slope reserves, British Petroleum, Atlantic Richfield, Exxon and Sohio, repeatedly emphasizes that "state approval of the gas offtake plan is needed now to insure that FPC (Federal Power Commission) certification, final design, financing and construction of the pipeline can proceed on schedule."

It defends the proposed offtake rates on the grounds that they would "immediately increase current energy to the consumers and

current income to the owners."

State Natural Resources Commissioner Guy Martin says that considering the massive investment the oil industry has in Prudhoe Bay, including \$7 billion in trans-Alaska oil pipeline costs alone, he was not surprised that the industry has balked at financing a massive water injection project or may be willing to sacrifice long term oil production for early gas profits.

"They would love it if the state would give them a guarantee, but we won't," Martin says. "It may be they have a disincentive to produce oil because they have a surplus on the West Coast and an incentive to produce gas because it's very dear right now."

"But I think they know that in order to get the levels of gas production they are talking about under our conservation statute, it is going to be necessary for them to have to have a water injection plan."

Without a commitment for massive water injection, Martin says the state probably will not set an initial gas offtake rate of more than about 1.6 billion cubic feet a day, a figure that is below the threshold of feasibility for two of three competing gas pipeline projects.

And even with water injection, Martin says the state won't give the industry any absolute guarantees in advance for the estimated 20-year life of the field.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.

TESTIMONY FOR ROYALTY GAS SALES CONTRACTS

Jefferson B. Barry, Anchorage, Alaska,
representing Teamsters 959
February 19, 1977

Senator Kay Poland, Chairman, Resource Committee,

Senator John Sackett, Chairman, Finance Committee:

The instant issues before the legislature are the royalty surplus gas sales contracts, but they are admittedly only a stimulus for the larger issue of an all-Alaska gas line with access of our own gas for our own uses. Since this is the only legislative forum available our testimony will include the entire matter.

On the instant issues of the royalty surplus gas sales contracts we support the legislative concurrence, provided certain modifications are incorporated:

1. (a) In the Tenneco Alaska, Inc. contract substitute the words of 40% instead of 50%.

(b) In the El Paso Natural Gas Company and the Southern Natural Gas Company contracts, substitute the words of 20% instead of 25% for both of such contracts.

It is vital and necessary that Alaska demonstrate there is an immediate intrastate use for domestic, residential, and power use of a portion of our gas. Certainly the ability to ship LNG to communities within our state must be present and the current application requests of Fairbanks honored.

I point out the most dynamic and stable growth area in the state has been Cook Inlet. The great denominator comes with natural gas for power, industry, and domestic, residential use. The rest of our state is surely entitled to those same opportunities. With an assured supply other communities can plan to realize those advantages.

As for Anchorage, Thomas Stahr, Manager of M.L. & P., testified before the Joint Committee that gas committed to the Anchorage area will run out in the mid-1980's and the

state must assure that Prudhoe Bay royalty gas is available for in-state use.

It is equally important the Federal Power Commission have this contract understanding. Judge Litt, on page 20 of his initial decision, addresses the question of the state contracts and he states, "...given the contract terms, such support is entitled to little weight. The purpose of such reservation is to insure that the amount of royalty gas exported from the State is 'surplus'--whatever that means--to the 'State's intrastate domestic and industrial needs'--whatever that means." And, in a footnote, "Upon reflection, Alaska decided not to seek a reopening of the record for the appearance of a state witness with respect to the contracts."

Upon the evidence presented to Judge Litt he had no knowledge that the vast majority of Alaskans have never had the energy benefits of natural gas or that the small area that has may soon be blacked out.

You should modify the contract to show that Alaska reserves the use immediately for 2.5% of its own gas within the state. Only in that fashion can the FPC make an evidentiary judgment of the need and meanings of our contracts.

2. The section of the contract 11.4 should be modified to clearly illustrate the State's interest is solely the El Paso Company docket #CP75-96 and the conditions apply to none other than the El Paso proposal.

There are ample time limits incorporated in Public Law 94-586 The bell tolls for thee and me as follows:.

Sec. 5(b). The Federal Power Commission shall submit to the President not later than May 1, 1977, a recommendation--

Sec. 7(a) As soon as practicable after July 1, 1977, but not later than September 1, 1977, the President shall issue a decision--

Sec. 7(2) The President, for a period of up to 90 additional calendar days after September 1, 1977 may delay

the issuance of his decision and transmittal thereof--"

Sec.8(a) Any decision--shall take effect upon enactment of a joint resolution within the first period of 60 calendar days of continuous session of Congress--"

Thus, it is clear the governor of Alaska has all of the necessary time by Federal statute to obtain the statutory requirements of approval by Legislative concurrence to "switch" any route assignment other than El Paso.

We believe the inclusion of 11.4 in the contract is destructive to the proclaimed intent of total support for the El Paso pipeline and a studied attempt to thwart legislative concurrence.

It is interesting to note the Federal Law 94-586 authorizing the Presidential decision requires Congressional affirmation. So do Alaska's laws. But this contract would abrogate that decision process by granting the Governor the power to "switch" without Legislative concurrence.

It would be a bad precedent to establish. We are totally opposed to 11.4 and suggest it be eliminated from the contract.

This concludes our testimony upon the minimal modifications required to approve the royalty gas sale contracts.

We now address the larger, most salient issue of the all-Alaska Gas Line and approval thereof according to the Alaska Natural Gas Transportation Act of 1976.

Congress has mandated certain actions, and many without judicial review. These are going to occur and the only course we may pursue is to adapt to them.

ACT AND INTIAL DECISION

The best place to begin is with Public Law 94-586, the Alaska Natural Gas Transportation Act, pointing out several emphatic statements:

Sec. 2.(3) "--delivery of Alaska natural gas to United States markets is in the national interest;-

Sec. 3 "--To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made,--"

Sec. 4(1) the term "Alaska natural gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

That's the heart of the matter. Congress has enacted a law in the national interest and will exercise its constitutional power to the fullest extent, and Alaska natural gas means ALL OF THE GAS NORTH OF THE BROOKS RANGE OUT INTO THE CONTINENTAL SHELF.

The implications are horrendous. From the largest gas reserve on the North American continent, from its own land, Alaska may not get one cubic foot of its own gas from Prudhoe Bay, from undiscovered sources in the Beaufort-Chukchi Seas, nor may gas discovered on Native Lands in that area be available for other Alaskans and communities.

If the Canadian Arctic route is approved the result is an expropriation of Alaska's property and energy. Most Alaskans want access to their gas, and certainly want the national interest of the lower 48 served with the vast amount of reserves on the North Slope.

Prior to the enactment of PL94-586 and concurrent since, the Federal Power Commission hearing process commenced on May 5, 1975, and essentially has continued almost uninterrupted since that time.

The record closed on November 12, 1976. It consists of 253 volumes of transcript, embracing almost 45,000 pages, about 1,000 exhibits (some, such as the environmental impact statements being almost 1,000 pages each), and innumerable items by reference.

Roughly, half the States, most of the U. S. natural gas pipelines, and a plethora of prospective purchasers and other interested parties intervened.

On February 1, 1977, the Federal Power Commission issued Order No. 558B:

The parties that have participated as adversaries during the long course of hearings have had more than adequate opportunity to place on the record their positions regarding the competing projects and the "data, views and arguments" in support of their positions. The quality of information available to the Commission would not be enhanced through mere repetition of that discourse. Furthermore, an unqualified departure from the principles of the ex parte rule would create a potential for unequal access by the competing parties to the decision process without contributing reliability to the result. Therefore, the Commission or delegates should not communicate in relation to substantive matters with the applicants or affiliates thereof or parties, counsel, or witnesses (including Commission staff witnesses) that have advocated on the record the approval or rejection of any of the competing projects.

For more than 2 weeks we have been analyzing Judge Nahum Litt's 430 page Initial decision.

It provides a shocking indictment of the State Administration concept of the Federal Power Commission hearings and the consequences of the enactment of the Alaska Natural Gas Transportation Act. The Administration has been remiss and derelict in its obligations to Alaska's citizens.

The record is replete with the evidence that the State Administration had no clear purpose nor pursued a determinative goal compatible with extraordinary Federal legislation and regulations. It is no wonder that Judge Litt perceived the State so poorly, and I intend to place that performance in the record.

The State was dilatory and uncooperative.

Page 12.

Upon the commencement of the hearings in May 1975, a running dialogue was instituted with the State of Alaska and producers seeking, inter alia, to ease them to a position where they might perceive that their best interests coincided with the national interest to have contracts for sale submitted at the earliest time during the pending hearings. This effort was singularly unsuccessful insofar as sales agreements were concerned, although some progress was made in at least getting the Producer to discuss these matters on the record. Only on the last day of hearing, November 12, 1976, did the State announce sales of its royalty gas to El Paso Natural Gas Company, Southern Natural Gas Company, and Tenneco Alaskan, Inc. But even these contracts for the royalty gas are not effective until ratification by the State legislature, which is not in session.

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of course which has burdened this record. Thus, while stating their concern for the national interest and the requirements of this country for energy at an early date, their prime consideration for early sale turns on other more parochial interests. The only conclusion possible from their actions is that the national interest to ARCO, Exxon, Sohio, etc. lies somewhere below their own

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economic interest, or at least, the national interest of the U.S. appears to them as negotiable in their bid to obtain certain concessions from the Commission or the Congress in return for their cooperation in bringing this gas to market. 1/ Admittedly, the uncertainty of regulation is not as bankable as the 3/4 billion dollars ARCO, for example, had negotiated as advance payments by prospective Alaskan gas purchasers before the Commission found such payments against the public interest. But it shows that the producers, like G.B. Shaw's dinnertime companion, have a price at which they would sell their "service," and all of their protestations to the contrary cannot hide that they are mainly dickering over price. The record, unfortunately, now stands with no firm commitment on the part of any producers to sell natural gas, or even that they will agree to sell it immediately upon tentative certification of a successful applicant.

The State of Alaska's role as a royalty owner, taxing agent, and conservator of its resources is also at issue. The State of Alaska embarked early on upon a course designed to maximize the economic benefits flowing to Alaska from its hydrocarbon resources. This laudable goal for Alaskans, unfortunately, is not always consistent with the general public interest of all of the people of the United States. It may portend, again unfortunately, a confrontation on the merits of an indirect transfer of payments from other parts of the country to Alaska through excessive payments for Alaskan hydrocarbons. These are not easy questions: the State's demands were not crudely put nor outrageous on their face. The difficulty is that they are also not always obvious, and it is not easy to gain a clear picture of the State's demands or whether those who deal with the State privately are in a position to bargain effectively for the public interest. Any Prudhoe Bay field operating plan must be sanctioned by the State, and the producers may, for example, agree to conditions in the field production arrangements which could be quite detrimental to long-term consistent sales of interstate gas.

In addition to the lack of sales agreements, there is still no approved production agreement for oil or gas from the Prudhoe Bay Field. A draft agreement was presented to the parties for the first time on August 18, 1976, some 7 or 8 months after it was first suggested it might be filed.

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The producers state that once the necessary pipeline and conditioning plant are in place, gas deliveries of at least 2.0 Bcf/d will commence. No one at this time questions the producers' statement that there is a 4-6 year lead for constructing the gas conditioning plant. The volume itself is termed as conservative, and they state that initial gas deliveries of up to 2.5 Bcf/d may be justified without affecting ultimate oil recovery. Produced water will be reinjected into the field, and the producers cite studies

indicating further potential for increasing oil recovery by implementing a source-water injection program. However, at least two years of testing are said to be necessary after the field goes into oil production before the final decision is made to construct source-water injection facilities. In approving the plan, an issue may exist between the producers and the State as to the need for, and timing of, source-water injection.

The vast weight of the evidence is that between 2.0 Bcf/d - 2.5 Bcf/d of gas will be available initially from the Prudhoe Bay Field.

What has occurred this past week? Commissioner Guy Martin received front page coverage by stating that "without a commitment for massive water injection the State probably will not set an initial gas offtake rate of more than 1.6BCFD, a figure that is below the threshold of feasibility for two of three competing gas pipeline projects."

Incidentally, one of those not feasible is El Paso.

It is simply incredible confusion. Early in the hearings the State exhibited the Van Poolen report which confirmed the 2 BCFD and even higher recovery rates by further water injection. No place in the record is there the hint of a 1.6 BCFD recovery rate. It is fully understood that for the years between oil production and gas line completion that the gas will be reinjected in the gas cap, approximately 4-5 years.

Now, at this late date, Commissioner Martin is compounding the confusion for those who must make timely decisions.

This threat, by unilateral decision, to restrict recovery rate below feasibility of El Paso and Arctic proposals cannot improve our "parochial image of self-interest."

It is one thing to argue with the producers and protect the conservation of our oil and gas. However, it is entirely a different matter when Alaska fails to enter into the records a clear position of policy whenever any relevant facts are known.

The acute shortage of natural gas in the lower 48, our possession of 10% of the nation's supply, should have

mandated the Administration to take a leadership role in the choice of the route selection.

But examine the record:

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(Alaska Initial Socio-Economic Brief, 12):

The El Paso project would create far more employment within the State, would increase population along the southern coast of Alaska to the extent that that portion of the State at least would have a private economy of reasonable size, and would provide far greater State and municipal revenues in order that the governmental units can cope with the socio-economic costs that are certain to result from any of the projects. When the benefits of the El Paso project so far outweigh any of its costs, and when its net socio-economic benefits would so far exceed those of the Arctic Gas Projects the State cannot conceive of refusing to grant the El Paso project a preference on socio-economic grounds....

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D. Intrastate Use of Royalty Gas

Alaska argues that, in addition to favorable impacts on employment, population, gross state product and net government revenues, the El Paso project will allow and in fact encourage industrial development in central Alaska. The State, eager to shed its dependence on the lower 48 states and its unstable, boom-or-bust economy, envisions the development of mineral reduction, fertilizer, cement, and petrochemical industries that can use the royalty share of the Prudhoe gas. 1/ Langhorne Motley, Commissioner of Commerce and Economic Development for the State, testified to the importance of this development and the potential for enticing industry into the State once the gas pipeline is completed. However, no cost-benefit analysis was performed concerning the intrastate vs. interstate use of royalty gas. On the whole, moreover, he was unable to detail concrete examples of discussions with prospective industrial users, and the State's use of Alaskan gas remains speculative, at best. The fact is that Cook Inlet gas supplies did not spur any substantial development, although Alaska argues that development of Cook Inlet gas involves piecemeal discoveries at a time when there were sufficient supplies of low-cost gas in the lower 48 states.

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- 1/ Guy Martin, Commissioner of Natural Resources for Alaska, indicated that the State would also benefit from a gas liquids removal plant built in Alaska, if El Paso was certificated.
- 1/ Governor Hammond testified that an oil refinery is planned for the Fairbanks area. Thus, there will be energy supplies available to central Alaska, even absent a trans-Alaska pipeline (96/14,675). Moreover, it should be noted that the use of gas for residential purposes in a cold climate such as Alaska's might be economically impractical, given the necessarily high fixed costs involved and the poor load factor.

In sum, there are so many uncertainties involved in intrastate use of royalty gas that no findings that it will occur are warranted at this time.

This is an unbelievable record for Alaskans to accept. Why was no cost-benefit analysis made? Why were not communities consulted for the use of natural gas, LNG, or LPG? Why were not the requests for Fairbanks users not part of the record? (downtown Fairbanks has had piped propane for business uses for about 20 years). Why were there no concrete examples of prospective industrial users--when Dow Chemical, for one, had made a proposal to the previous administration; that Dupont, Celanese, Rexall, to name some prospects, have indicated interest?

There aren't so many petro-chemical companies that the State Administration would have been burdened to have sent letters of inquiry over possible interest.

The lack of such attention to Alaska's intra-state use is magnified by the sales contracts to be shared by Tenneco 50%, Southern 25%, and El Paso 25%. When the FPC staff and Judge Litt examined the evidence of the record they properly found no consumers nor identifiable prospective users.

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The major benefits the State derives from the El Paso proposal are the jobs and tax base of a multibillion dollar, 800-mile pipeline and LNG facilities, the liquid removal plant which would be built by the producers in Alaska (probably at Gravina Point), the additional industry which would settle in the State to utilize cheap energy, and the multiplier effect upon the State's economy by all of the above. But the result of giving disproportionate weight to these considerations and choosing an all-Alaskan route even if more expensive, rather than basing the decision on an analysis of costs and benefits which redound to all consumers, is no different than that already rejected by the Commission and the courts.

The Administration did not make a case for Alaska.

Next, let's look at the greedy image portrayed by the State's evidence:

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One of the prime reasons for these high projected prices for delivered gas, of course, is evident from the makeup of the project. Rather than the usual business compromises arranged both to make a marketable product and to split the benefits among those who will gain the financial advantages from a successful venture, all of the prospective beneficiaries are looking for the top dollar. The producers and State of Alaska want a high wellhead gas price even though (1) their overall profit from their North Slope investment is already assured by the sale of the Prudhoe Bay oil under FEA regulations, (2) the product is at the end of an expensive transportation system, and (3) the market is no longer assured. Governor Jay S. Hammond of Alaska, for example, sought and will probably seek again Alaskan legislative approval to raise the severance tax on hydrocarbons from 4% to 10%, Access without equity contribution, 3/ withdrawal, underlifting and a host of other proposals put Alaska in the forefront of seeking special treatment at the consumer's expense. As discussed in the rate-of-return section, the pipeline shippers want consumer guarantees to repay their equity investment but still seek 15% to 17% after tax return in what could be a low-risk situation. The financial community in general also wants a high rate of return regardless of how the risk might be reduced by consumer or taxpayer guarantees. In the common vernacular, "everyone has his hand out."

According to the record it appears Alaska has both hands out --- high well-head prices, high taxes, and no risk.

It is also interesting to note then El Paso raises the specter of Canada or the provinces imposing heavy taxes but is the Governor of Alaska who is in the record for a 150% increase.

There is no evidence the State of Alaska, the beneficiary of billions by the marketing of Prudhoe gas, has offered any incentives or economic inducements toward the resolution of the route, the facilities, or field systems.

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The field prices to be paid by shippers to producers for gas volumes delivered into the transportation system will reflect more than just the purchase of the commodity itself. Between the well-head and the delivery point, there must be constructed an extensive gas gathering system and conditioning plant at a total capital cost, excluding interest during construction, estimated by the producers to be \$1.8 billion. This cost, the producers aver, must be borne by the shippers. It is readily apparent that these facilities will not "cost out" at the few cents per MMBtu familiar from past area and nationwide rate proceedings. Producers

have presented short-hand calculations, based upon the Arctic Gas project costs, suggesting that the unit cost of gathering and conditioning to be borne by the shippers will approximate one-half the unit cost of the transportation system (213/36,931 et seq.). 1/ One need not rely on these unsupported and untested calculations to realize that, given the magnitude of the capital investment, the unit cost will be high. All of these high transportation and field facilities costs are bad news for consumers--and for the producers and the State of Alaska.

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Nor, according to Governor Jay S. Hammond of Alaska, has the State seriously considered offering any of the applicants financial assistance (96/14,688).

The State has gotten itself into a legal hassle, over jurisdiction of interstate sales and its proposed royalty sales.

How serious Judge Litt viewed the legal question is confirmed by his proposed legislation to delete Section 13(A) and (B) from the Act.

To begin with, respecting wellhead sales in Alaska, jurisdiction is unquestioned only as to interstate sales by the corporate producers. The State of Alaska resolutely denies federal jurisdiction over its interstate sales.

The State of Alaska's position, in the Presiding Judge's view, is contrary to the law and to effective or equitable regulatory control. The sole basis for its denial of jurisdiction is the claim that a State is not a "person" within the meaning of Section 2 of the Act. 1/ Thus, activities which, by their nature, Congress intended to place under regulation are said to be exempt when performed by a State. There is no such gap in the law, and one should not be created. The producing and energy-rich States of the nation, by virtue of their royalty interest where production is from state land and their increasing propensity to reserve the right to take that interest in kind, will have the ever-growing ability to dispose by sale of larger and larger volumes of gas and will expand such a gap to permit larger and larger volumes to escape regulatory control. In this proceeding alone, Alaska has recently entered into contracts to sell in interstate commerce up to 2.6 Tcf of its royalty gas.

Alaska's jurisdictional argument, moreover, is hardly compatible with the Act's purpose to afford consumers an effective bond of protection against excessive rates 1/ or the intention of Congress "to give the Commission jurisdiction over the rates of all wholesales of natural gas in interstate commerce ..." (emphasis added). 2/ Furthermore, Alaska's essential premise is undercut by the holding in F.P.C. v. Corporation Comm'n of Oklahoma, 362 F. Supp. 522; aff'd 415 U.S. 961 (1974), that a state agency is a "person" within the meaning of Section 2 of the Act and thus the U.S. District Courts have jurisdiction under Section 20(a) to enjoin its actions violative of the Act or

regulations thereunder. The question of jurisdiction over Alaska's proposed sales is not squarely at issue in this proceeding, and the parties have not provided legal argument on the question only because sales contracts were not filed earlier. The need for the Commission to give prompt attention to and definitively resolve the matter is apparent, since any attempt to finance these projects must be predicated on knowledge of the transactions that are jurisdictional. 3/

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XVI

PROPOSED LEGISLATION

A. Section 13 of the Alaska Natural Gas Act of 1976

The State of Alaska has entered into contracts for the interstate sale of its royalty gas which include provisions permitting the State to subsequently withdraw the gas from the interstate market for use within the State. These withdrawal provisions are sanctioned by Section 13(b) of the Alaska Natural Gas Act of 1976.

However, as discussed in the Jurisdiction and Financing sections of this Initial Decision, substantial difficulties arise from the State's asserted right to commit its gas to interstate use with one hand and take it back with the other. The mere prospect of withdrawal imperils the financeability of an Alaskan gas project; actual withdrawal would idle downstream facilities and in turn produce adverse cost impacts.

Moreover, when the Section 13(b) withdrawal provision is coupled with the Act's "equal access" provision, 1/ it becomes readily apparent that the statute in its present form could operate to confer a substantial indirect subsidy to the State. Assuming that the project could be financed and completed, that Alaska's interstate customers (El Paso Natural, Tenneco Alaskan, and Southern) participated in the equity financing with consumer guarantees, and that Alaska thereafter found an intrastate use for its royalty gas, the consumers of the three customer companies would have risked their dollars to help finance the project, only to see consumers in Alaska reap the reward.

For the reasons stated herein, the Presiding Judge respectfully suggests that the Commission, in its recommendation to the President, give consideration to the desirability of amending the Alaska Natural Gas Act of 1976 to delete therefrom Sections 13(a) and 13(b). Absent deletions of these two provisions, direct and total U.S. government guarantees would appear to be the only feasible method of financing.

1/ Section 13(a) of the 1976 Alaska Natural Gas Act would deny the Commission the power to limit access to the transportation system to shippers participating fairly in its equity financing. It is questionable whether the proposal to finance an Alaskan project with consumer guarantees is possible in the face of this statutory provision.

I don't question the wisdom of the State seeking a confrontation with the FPC over jurisdictional matters but the timing and circumstance could hardly have been worse.

The avowed intention of the State to gain a trans Alaska route with access to its own gas has not been pursued with a vigorous policy, nor has there been a determined exploration of ways and means to gain those goals. We do not believe the Administration has demonstrated the ability to comprehend the multitude of problems remaining nor the will to take affirmative action in the short time left before a final decision is made.

Our hopes rest with this Legislature to provide the leadership so lacking in the hearings up to now.

Of the twenty-four (24) states which intervened, Alaska is the only state which supports El Paso. Only two gas line companies support El Paso; Tenneco and Southern. Intermountain Gas (Idaho) alone supports Alacan. The large majority of States, gas transmission and distribution companies support Arctic Gas. The FPC staff report and Judge Litt's initial decision recommend Arctic.

Perhaps the Governor may be correct that the political lobbying of Tenneco and Southern will tip the decision by the President and Congress in favor of El Paso over the immense weight of Arctic Gas support.

But we aren't willing to rest with those odds, nor do we think the people of Alaska are.

We know there are ways that the State can take effective action, that there are ways to demonstrate our concern for the National interest, and a cost-and-benefit plan which rebounds to all consumers.

Judge Litt pointed the way a number of times in his decision and, in one instance, hung out the beacon of two lights in the old North Church, if by sea.

On pages 361 - 362 "It immediately became apparent that the only traditional credit-worthy parties involved in this proceeding whose added credit could permit conventional financing were the two direct financial beneficiaries of Alaskan natural gas sales -- the producers and the State of Alaska. Despite the billions each will reap from the sale of Prudhoe Bay hydrocarbons, neither has shown any particular interest in investing in a transportation system to market gas or otherwise assist in its financing."

Page 363 - 364 THE BEACON

As far as the State of Alaska is concerned, there is no record evidence that other states have participated in financing this type of gas pipeline project. It is not that financing utility and industrial projects through municipal bonds, direct ownership of generating facilities (e.g., New York) or forgoing certain taxes is unknown to states seeking to ensure an expanding economic base. Given the avowed intentions of the State to invest its revenues and the high rate of return suggested here for either equity or debt, the State may see this as a better investment than it can receive elsewhere. 2/ If, in addition, tariffs require the ultimate consumers to shoulder full debt service responsibility and the bonds issued achieve debt ratings satisfactory to the New York State Insurance Commission, they would probably also satisfy the

State of Alaska's investment trust fiduciary. 1/ Nevertheless, such investments are voluntary, and the State of Alaska has not volunteered.

- 2/ While it might be unkind to suggest, there is a likelihood that the State might be willing to aid El Paso if it appeared that such offer might tip the choice towards the State's first love. The State's excellent presentation, through a range of perceptive and knowledgeable witnesses, does not permit ignoring that such an obvious suggestion may be made at a propitious time in the decisionmaking process.

This is the "Open Sesame" for Alaska. Either equity or debt participation, or both may tip the decision.

Because the State and producers have not come forward as a creditworthy party to assist, Judge Litt

proposed Federal Financial Participation legislation:

"The Treasury Department should be granted statutory authority necessary and appropriate to accomplish whatever Federal participation in the Alaska gas project financing is ultimately determined to be required in the public interest."

Replete through the decision, especially in the section of Economics, Socio-Economics, Cost Allocation, and Financing and Tariffs are statements that Federal guarantees will be required, that ultimate costs will be borne by the consumers with taxpayer backing in order to offset the risks so that money can be raised in the financial community.

We propose the establishment of an Alaskan Gas Authority for ownership of the gas pipeline, production, and terminal facilities.

Precedents to such an Authority are everywhere. To mention a few, Tacoma and Seattle generate power for the lowest electrical rates in the nation, the Public Utility Districts along the Columbia River furnish power throughout the Northwest and sell 17 billion kilowatts to California annually, the Seattle Port Authority operates the seaport of the city as well as Sea-Tac Airport. States have built dams, gas, coal, and oil generation and transmission systems; they have constructed bridges, toll highways, airports, and marine transportation systems. In our own state we operate three international airports and a ferry system. Nationally, the T.V.A., dams, etc.

Whenever the needs for energy and transportation have been perceived and an opportunity is available to meet those needs, government--local, municipal, county and state--have responded by guaranteeing the means to meet those needs.

In our hour of greatest energy need that is what Alaska must do.

If we are to gain our own energy independence we must act resolutely to prove we have the will and determination to manage our own destiny.

The magnitude of this proposal is immense, but not at all insurmountable. A number of financial experts representing major bond firms and banking institutions have stated it would be a joy to participate in the underwriting of tax exempt revenue bonds.

As an illustration, let us incorporate for \$6,000,000,000.00 in tax revenue bonds and use 6% as the effective rate of interest. (Incidentally, the City of Valdez sold the first \$262 million bond offering on Feb. 7 at a 5.94% rate)

At 6% the maturity payback will be:

\$11,658,000,000.

\$ 5,658,000,000. interest

At 10% (page 269 "The applicants' financial witnesses estimate a debt cost of approximately 10%, based on a Baa bond rating, and the applicants seek 15% to 17% as an after-tax return on equity.")

\$16,432,800,000. maturity pay back

\$10,432,800,000. interest.

Thus, the first savings on this huge debt would approximate \$4,774,800,000. which will be reflected in a lower tariff paid by our fellow consumers in the lower 48.

But there is even a greater ancilliary savings to be achieved for another lowering of tariffs. All of the applicants are seeking 15-17% profit as an after-tax return on equity.

The combined U.S. and Alaskan income tax rate of 52.89% requires pre-tax revenues of \$212. to provide \$100. in after tax income. Combined taxes in Canada would require \$221. of revenue.

Taken together these are very substantial cost-benefits to the American consumer.

Another major savings will occur in State ownership and construction of the gas conditioning plant at Prudhoe Bay. Page 1, Appendix C --- " Preliminary estimates made several years ago indicate the plant will require 4 - 6 years to design, fabricate, and construct, and will cost about \$ 1 billion (1975 costs)"; with the financing assured (not having to wait until the entire transmission system has been funded) work could proceed expeditiously, assuring quicker delivery and saving whatever the annual inflation rates would be.

There are other beneficial reasons including State responsibility of maintaining the integrity of construction and operation of the gas pipeline. The State also has the greatest interest in the maximum utilization of oil and gas from the Prudhoe field as well as the undiscovered reserves in the Beaufort-Chukchi Seas.

How may we expect the Federal Power Commission to consider such a proposal?

Judge Litt will have found his credit-worthy party capable of providing the financing to guarantee the feasibility of the project. There will be no need to seek legislation for Federal guarantees. An updated cost-benefit analysis will reveal that the all-Alaska pipeline will rebound to all consumers. Because of the State's active participation, the remainder of the financing will be made measurably easier. Thus, it may be the "offer to tip the choice toward the State's first love."

We believe that President Carter, the Congress and our fellow Americans will regard Alaska with new respect as a full partner in the Union, not the new kid about to inherit great wealth but unwilling to share in the National interest. We believe that President Carter and Congress will understand our concerns and desires to become more self-sufficient and better able to provide for our people. We

believe President Carter and the Congress will look kindly upon us when it comes time to make the final decision.

SCOMM

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PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.

NATURAL GAS CONDITIONING AND PIPELINE DESIGN

A Technical Primer for Non-Technicians,
With Special Reference to Hydrocarbons from Prudhoe Bay
and the Alaska Highway Gas Pipeline

BY CONNIE C. BARLOW

Juneau, Alaska
March 11, 1980

Prepared for the State of Alaska
Department of Natural Resources

ARLON R. TUSSING & ASSOCIATES, INC.

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INTRODUCTION

The State of Alaska faces a variety of questions related to the proposed Alaska Highway Gas Pipeline which combine highly technical engineering considerations with important public policy issues. These questions include:

- location, design, and ownership of the gas conditioning plant,
- choice of fuel for North Slope operations, and
- pressure and diameter specifications of the pipeline itself.

Some grasp of the engineering jargon and basic principles is essential if Alaska's elected officials and agency staff are to identify the State's priorities correctly: What issues really affect the State's interests, and to what extent? Which, if any, of the other parties --- the producers, gas shippers, and federal authorities --- are likely to share the State's interests in each of these questions, and to what extent? How much can Alaskans depend on others, therefore, to look after the State's interests? How formidable is opposition likely to be to the State's position, and what burdens would the State's demands impose on others? Overall then, where should the State realistically direct its efforts?

This report, in itself, will not answer those questions; it should, however, make State decision-making a bit easier. We have tried to distinguish scientific facts from matters of differing engineering judgment, and both from differences of economic interest; and to present the range of opinions fairly. Our goals have been to develop a primer on gas conditioning and pipeline transportation that is relevant to Alaskans, speaks to non-technicians, yet is precise and complete enough to survive the scrutiny of experts.

Special thanks goes to Harold R. Galloway and James L. Shanks, Jr. of Exxon, D. J. Pritchard of Sohio, W. S. Dickinson of Arco, A. J. Green of Westcoast Transmission, Robert M. Maynard of the State of Alaska's Department of Law, and Robert H. Loeffler of Morrison & Foerster, the State's Washington counsel.

I. THE BASICS OF PIPELINE DESIGN

A. HYDROCARBON CHARACTERISTICS

1. Chemistry

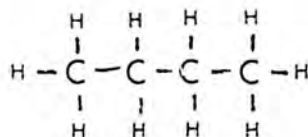
The crude oil and natural gas produced from Alaska's Prudhoe Bay reservoir are mixtures of hydrocarbons (compounds of carbon and hydrogen), plus impurities like water and carbon dioxide. The most fundamental classification of hydrocarbon compounds is in terms of the number of carbon atoms in each molecule.

TABLE 1

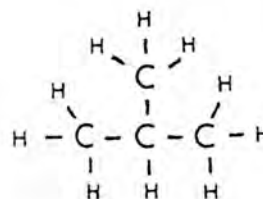
<u>Reservoir Fluid</u>	<u>Compound</u>	<u>Chemical Formula</u>	<u>Abbreviation</u>	<u>Commercial Product</u>
natural gas	methane	CH_4	C_1	dry gas
	ethane	C_2H_6	C_2	
	propane	C_3H_8	C_3	natural gas liquids (NGLs) or condensate
	butane	C_4H_{10}	C_4	
crude oil	pentane	C_5H_{12}	C_5	natural gasolines, naphtha, or pentanes-plus
	hexane	C_6H_{14}	C_6	
	heptane	C_7H_{16}	C_7	
	octane	C_8H_{18}	C_8	
	-	-	-	oils, waxes, tars
	-	-	-	
	etc.	C_nH_m	C_n	

Hydrocarbons containing more than three atoms of carbon in each molecule have several different configurations. These forms or "isomers" often have different physical characteristics. For example, Table 2 shows that "normal" butane [n-butane] can remain in a liquid state in the TAPS oil pipeline at higher temperatures than can the branched isomer "iso" butane [i-butane].

FIGURE A: NORMAL AND ISO-BUTANE



"normal" (n) butane



"iso" (i) butane

2. Heating values

The heating value of each hydrocarbon reflects, in part, the number of carbon atoms that will oxidize as the fuel is burned. Table 2 shows the heating values of light hydrocarbons and their isomers, both in liquid and vapor states. Normally, heating values are expressed in gross BTU's¹, also called the higher heating value. The expected heating value of gas that will be shipped through the Alaska Highway gas pipeline (or Alaska Natural Gas Transportation System [ANGTS]), for example, is invariably expressed in gross terms.

The lower heating value, measured in net BTU's, serves a very limited function, primarily in describing the fuel requirements for various types of machinery and processes. Net BTU's for hydrocarbon vapors have been used by some parties involved in the design of the North Slope gas conditioning plant; Table 2, therefore, includes net measurements for hydrocarbon vapors.

The difference between gross and net BTU's is highly technical. The reader need only remember that (1) unless specifically designated as net BTU's, one can assume that all heating value data represent gross measurements; and (2) like apples and oranges, the two should never be confused or mixed in heating value calculations.

1) A British Thermal Unit (BTU) represents the amount of heat required to raise the temperature of one pound of water by one degree F.

TABLE 2

HYDROCARBON	VAPOR HEATING VALUE		LIQUID HEATING VALUE
	BTU/scf [*] gross	BTU/scf net	BTU/barrel ^{**} gross
Methane	1010	909	2,512,818
Ethane	1769	1618	2,771,916
Propane	2518	2316	3,824,730
i-butane	3253	3001	4,158,924
n-butane	3262	3010	4,325,538
i-pentane	4000	3698	4,569,180
n-pentane	4010	3708	4,624,284

Source: Natural Gas Processors and Suppliers Association,
Engineering Data Book, 1979.

* A Standard Cubic Foot (scf or cf) is the amount of gas that would fill a cubic foot of space at 60 degrees F. and standard atmospheric pressure. The following abbreviations are often used to represent large volumes:

Mcf = thousand cubic feet
MMcf = million cubic feet
bcf = billion cubic feet
Tcf = trillion cubic feet

** One barrel = 42 U.S. gallons.

3. Phase characteristics

The more carbon atoms a molecule contains, the heavier it is. The heaviness of a particular hydrocarbon will influence whether it exists in a vapor or liquid phase at various combinations of temperatures and pressures. Table 3 shows the boiling points of light hydrocarbons. At temperatures below the boiling point, a hydrocarbon is a liquid; above, it is a vapor.

TABLE 3

SUBSTANCE	MOLECULAR WEIGHT	BOILING POINT (F.) [at atmospheric pressure]
C ₁	16.043	-258.69
C ₂	30.070	-127.48
C ₃	44.097	- 43.67
i-C ₄	58.124	+ 10.90
n-C ₄	58.124	+ 31.10
i-C ₅	72.151	+ 82.12
n-C ₅	72.151	+ 96.92
n-C ₆	86.178	+155.72
n-C ₇	100.205	+209.17
n-C ₈	114.232	+258.22
CO ₂	44.010	-109.30

Source: Natural Gas Processors and Suppliers Association,
Engineering Data Book, 1979.

Oil is now injected into the Trans Alaska oil pipeline (TAPS) at a temperature of 142 degrees F. At times, the oil may experience pressures enroute as low as normal atmospheric conditions. Under these circumstances, Table 3 shows that hexanes (C₆) and all heavier hydrocarbons would always remain in a liquid phase during shipment through TAPS. Mixtures of heavy hydrocarbons also have the ability to carry small quantities of C₅ and even C₄ without vapor formation. On the other hand, mixtures of the lightest hydrocarbons (C₁, C₂, and C₃) remain in the vapor phase even in a chilled gas pipeline, and can likewise absorb some C₄ and possibly C₅ without condensation.

The question of how much of these intermediate hydrocarbons (C_4 and C_5) will be carried as vapors by ANGTS, shipped as liquids in TAPS or in a third "gas-liquids" pipeline, used for fuel on the North Slope, or routed to some other purpose, remains open. Resolution of this issue depends upon a whole array of decisions, including pressure and temperature specifications for operation of both the gas and oil pipelines, the amount of CO_2 permitted in the gas pipeline, the choice of gas conditioning process, the kinds and amounts of fuel used in the field and for pipeline pumps and compressors, and oil and gas production rates. This report examines each of those factors, their relationships, and the ultimate effect such decisions may have on the kinds and amounts of hydrocarbons transported.

B. GAS VERSUS LIQUIDS PIPELINES

Pipelines carrying hydrocarbons in a liquid phase (such as the TAPS oil line and a proposed gas liquids line) use pumps to move these materials. Pipelines designed for gaseous hydrocarbons, such as the proposed Alaskan Northwest pipeline, use compressors. The difference is subtle, but important.

In liquids, the individual molecules are packed tightly together and, for all practical purposes, cannot be compressed into a smaller volume. Instead, as more molecules are pumped into a pipe, they shove the mass of hydrocarbons in front of them into the next pump station, like a train of boxcars pushed from behind. Naturally, the greater the distance (and the greater the rise in elevation) between pump stations, the greater is the horsepower required.

Gaseous hydrocarbons, like all vapors, are compressible. Each compressor station on a gas pipeline draws vapor into its inlet at a relatively low pressure (called the suction pressure), compresses it into a smaller volume, and expels it at a higher pressure, known as the discharge pressure. As the gas expands between the outlet of one compressor station and the inlet of the next, pressure again falls, and this pressure drop or differential causes the gas to flow through the pipe. It is the discharge or operating pressure, being the greatest pressure experienced by the pipeline, that is limited by the strength of the steel pipe.

C. PRESSURE SPECIFICATIONS

Pressure drop is usually measured as a ratio to distance, psi per mile.² Being the stimulus for gas movement through a pipeline, it is therefore one of several factors that determine how much gas can be transported each day. Throughput is determined by the following components:

- (1) Discharge pressure, (2) Suction pressure, and (3) Compressor Station spacing determine the pressure drop, and thereby the SPEED of flow, while
- (4) Pipeline diameter determines the AMOUNT of gas that can be shipped through a pipeline at any given speed.

-
- 2) Pressure is measured in pounds per square inch (psi). Objects at sea level are subjected to an atmospheric pressure of about 14.7 psi (which results from the weight of several miles of air resting on the earth's surface). Instruments designed to measure artificially induced pressures like those inside gas pipelines, record or gauge pressures in excess of this ever-present atmospheric pressure (psig). Absolute pressure measurements include the 14.7 psi exerted by the atmosphere (psia). Hence, 1680 psig is the same as 1694.7 psia.

Of these four variables, a pipeline's diameter and the maximum discharge pressure that it can accomodate (that is, the pipeline's operating pressure) are the only ones that cannot be altered once the pipe is laid. The other two can, in theory, be modified to accomodate changes in throughput: Throughput can be increased either by adding more compressor stations or by increasing the suction power of existing compressors.

There are, of course, practical and economic constraints on the number of compressor stations that can be added. Likewise, the suction power of compressors experiences a marked drop-off in efficiency beyond a given range of compression ratios.

The compression ratio is the ratio between a compressor's discharge pressure and its suction pressure. Compression ratios are generally in the vicinity of 1.2 to 1.3. Table 4 shows the suction pressures corresponding to a compression ratio of 1.25 at four operating pressure levels heretofore considered for the Alaskan and Canadian sections of the Alaska Highway Gas Pipeline.

TABLE 4

<u>Operating pressure</u>	<u>Efficient Delivery Pressure</u>
1680 psig	1350 psig
1440 psig	1150 psig
1260 psig	1010 psig
1080 psig	860 psig

The National Energy Board (NEB) has approved construction of a 1080 psig 56 inch diameter pipeline in Canada. Though some contention still exists on the matter, the Federal Energy Regulatory Commission (FERC) has approved the design proposed by the pipeline sponsor, Northwest Alaskan,

with an operating pressure of 1260 psig for a 48 inch pipeline in Alaska. EXXON and the State of Alaska have advocated higher operating pressures, such as 1680 psig (or even 2160 psig for a 42 inch diameter pipe). ARCO at one time proposed a compromise pressure of 1440 psig.

The controversy over the pipeline's operating pressure and diameter stems, in part, from a recognition that manipulating discharge and suction pressures or even building more compressor stations after the pipe is laid are not necessarily the most economic or practical responses to future changes in throughput. For these reasons, designers must choose pipeline diameter and wall thickness specifications and compressor station locations that reflect a realistic judgment of likely throughputs over the life of the facility. FERC and Northwest concluded that a 1260 psig 48" diameter pipeline is the most efficient and economic compromise for the volume of gas expected from the main Prudhoe Bay reservoir (about 2.0 bcf/day). However, they agree that at a throughput somewhere between 2.6 and 2.9 bcf per day, a 1680 psig line would make more sense. ["Report of the Alaskan Delegate on the System Design Inquiry", FERC, May 17, 1979; p. 27.]

Unfortunately, the additional volumes of North Slope gas likely to become available during the expected 20 or 25 years of gas pipeline operations are both uncertain and controversial. No one can know with confidence whether the 1260 psig system ultimately will prove to be the best choice.

A related issue that must be addressed during engineering design is the need for crack arrestors. Even if a pipeline's wall thickness is sufficient to withstand its own INTERNAL gas pressures, pipeline designers have to safeguard against the effects of catastrophic EXTERNAL forces --- such as a misguided bulldozer or a saboteur's bomb.

Obviously, localized damage cannot be prevented entirely. In a large diameter, high pressure gas pipeline (unlike TAPS), however, even a small injury to the pipe can result in a fracture that spreads explosively up and down the system, perhaps destroying pipe for tens of miles. Girdling the pipe at regular intervals with sturdy metal crack arrestors is one solution.

Virtually everyone agrees that a 1680 psig, 48 inch diameter pipeline must be equipped with crack arrestors. Opinions, however, vary with respect to a 1260 psig system. Since crack arrestors are a significant expense, no conclusive judgment about the relative economic advantages of a 1260 psig system can be reached in the absence of a decision on the need for crack arrestors.

Probably the biggest source of controversy with respect to the selection of an operating pressure for the Alaska Highway Gas Pipeline centers, however, on the ability of higher pressure pipelines to carry heavier hydrocarbons without risking two-phase flow.

D. HAZARDS OF TWO-PHASE FLOW

Long-distance pipelines must be designed to carry hydrocarbons either in a vapor phase (like the Northwest pipeline) or in a liquid phase (like TAPS and the proposed gas liquids line). Transporting vapors and liquids together in one stream results in a condition called two-phase flow. The dangers of two-phase flow are as follows:

(1) General problems of two-phase flow. A pump or compressor is designed to operate on material of a certain density. Encountering bubbles of vapor in a stream that should be totally liquid is a little like swinging a bat at a baseball and missing; while coming across droplets or, worse yet, big "slugs" of liquid in a stream that should be all vapor is like being hit with a barrage of snowballs. Either event can be rather jarring to the system.

(2) "Surge" and "slug" problems of two-phase flow. If droplets of liquids condense in the vapor stream, they tend to settle and accumulate in low spots along the pipeline, constricting the room available for vapor flow. As the amount of trapped liquid grows, pressure builds --- eventually forcing the liquid up and over the next hump. Large slugs of dense liquids are, therefore, accompanied by an uneven or surging flow of fluids. Extreme surging conditions can cause severe damage when a slug enters a compressor station.

It should be noted that some pipelines are intentionally operated in two-phase flow conditions, while gathering "wet" (unconditioned) gas in the field, or bringing gas from offshore wells to shore-based facilities. Usually, however, these pipelines are quite short and undersized; no pumps or compressors that could be damaged by surging slugs are located along the way. In fact, some offshore pipelines for which slug formation cannot be avoided empty onshore into several miles of convoluted pipeline called slug catchers. Here the tremendous force of the slugs is dissipated, and the liquid itself is "scrubbed" out of the gas, prior to entering pumping, processing, or compressing facilities.

Designers and operators of long-distance gas pipelines, like the ANGTS which has several compressor stations and many ups and downs enroute, can take a variety of actions to reduce the hazards of two-phase flow. They can:

- * Avoid building an oversized line. One way to prevent the accumulation of liquids at low points along the line is to ensure that vapors flow at a high speed. This means choosing a pipeline diameter appropriate to the expected throughput, maintaining a high pressure drop, or both. If a system is designed to carry an average of 3.0 bcf/day and only 2.0 bcf/day is available for shipment, pressure drop would have to be reduced in order to ensure a steady flow of the smaller volume of gas. The result is a slower movement of gas and, hence, a greater danger of slug formation and surging.

- * Equip the line with drains. Valves to drain off accumulated liquids can be inserted in low spots along the pipeline.

- * Ensure against sloppy pipeline operations. If drains are installed, they must be used properly. If adequate drainage is impractical, the line should receive more frequent "pigging" (insertion of a solid object, or pig, which pushes accumulated liquids out ahead of it). If throughput is raised or lowered, changes in the input and output pressures must be synchronized. If the line is shut down temporarily, special care must be taken when operations resume to prevent the passage of entrained liquids that may have formed during the outage. For these reasons, no matter how free of droplets the sales gas may be when it enters the pipeline, sloppy operations can result in dangerous two-phase flow conditions.

None of the above precautions are of much use in long-distance pipelines, however, unless pipeline operators also:

* Restrict the volume of heavy hydrocarbons. Pipelines must transport only hydrocarbon mixtures that pose no threat of condensation at any combination of temperatures and pressures likely to be encountered under either normal or abnormal conditions. Determining the optimum mixture is rather complicated, as the next chapter shows.

II. GAS COMPOSITION DECISIONS

A. INTRODUCTION

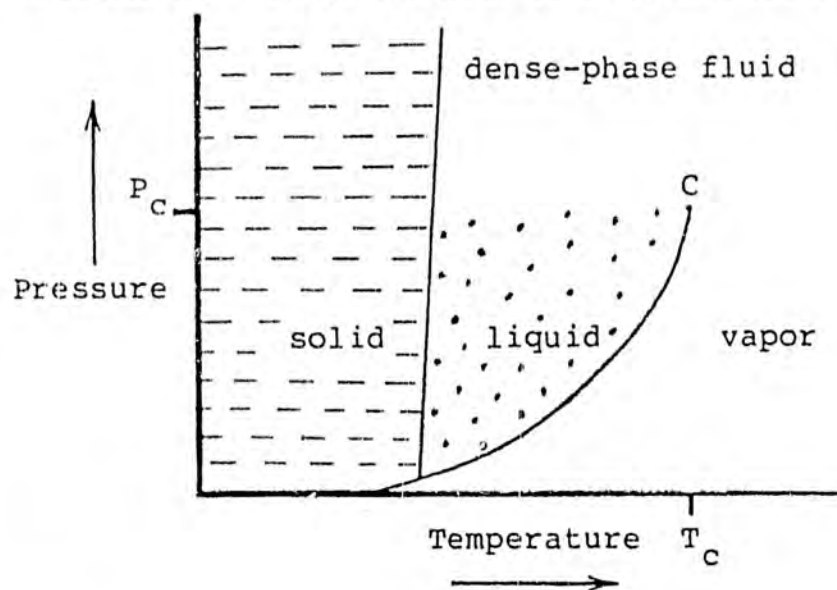
In designing a gas transportation system, everything seems to affect and be affected by everything else. We have seen, for example, that decisions about pipeline diameter, operating pressure, suction pressure, and compressor station spacing are all interdependent. Further, these specifications cannot be set intelligently except with reference to some volume or range of volumes for expected throughput. The same holds true with respect to determining the optimum chemical composition of pipeline quality gas; that is, the relative amounts of methane, ethane, propane, butane, heavier hydrocarbons, carbon-dioxide, water, and sulphur compounds in the gas delivered to the pipeline.

Temperature and pressure are the two factors that determine whether any particular hydrocarbon or mixture of hydrocarbons will be present in a vapor or in a liquid phase. Thus, pipeline designers must choose a balanced combination of pressure, temperature, and composition specifications that will ensure safe operations and avoid two-phase flow.

B. PHASE DIAGRAMS

Almost everyone is familiar with "bottle gas" -- pressurized containers of propane and butane used to fuel appliances in isolated homes, mobile homes, and recreational vehicles, and for camping stoves and lanterns. The propane or butane exists as a liquid inside the containers, but vaporizes upon release. Heavier hydrocarbons like gasoline and diesel fuel are liquids at atmospheric pressures and temperatures but vaporize when heat is added. These are all examples of phase changes. Each hydrocarbon has its own phase diagram, like that of Figure B, which shows how changes in pressure and temperature affect its physical characteristics.

FIGURE B: PHASE DIAGRAM OF A PURE SUBSTANCE



Notice first, that four phases are shown: solid, liquid, vapor, and something called dense-phase fluid. Unlike the other phases, it is hard to pinpoint where the dense phase fluid starts and ends; but we do know that it occurs only at extremely high pressures. It is also difficult to describe: A dense-phase fluid is dense like a liquid, but compressible like a vapor. And unlike solids, liquids, and vapors, which we all encounter in our daily lives, dense-phase fluids exist only deep inside the earth and within artificially created environments like natural gas pipelines.

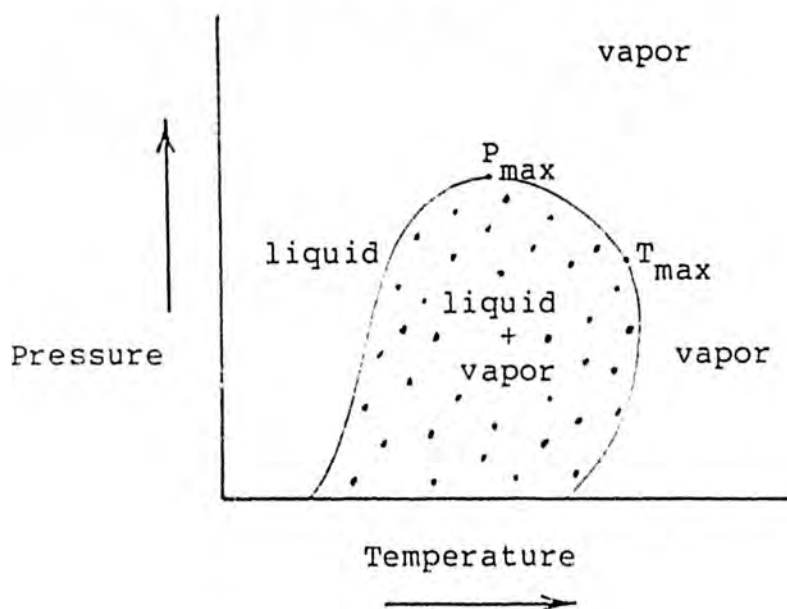
While this high pressure phase is technically a creature unto itself, for our purposes there is no practical distinction between such fluids and vapors, and we shall generally use the word vapor for both.

Point C in Figure B is called the critical point. For any pure substance, no liquid can exist at pressures above the critical pressure (P_c) --- no matter how far the temperature drops. Likewise, no liquid can exist at temperatures beyond the critical temperature (T_c) --- again, no matter how much pressure is exerted.

Unfortunately phase diagrams of hydrocarbon MIXTURES, like that of Figure C, are more complicated to read and understand than are the diagrams of pure substances. For volumes containing only a single hydrocarbon type, two phases will coexist only at pressure-temperature combinations represented by the thin line separating liquid and vapor phases. But for hydrocarbon mixtures, the net effect of all the individual phase diagrams is a tongue-shaped region or phase-envelope in which both gas and liquid states are present. To avoid two-phase flow in pipelines, therefore, any combination of temperature and pressure falling

inside the phase envelope must be avoided. Liquids pipelines must operate to the left of the phase envelope, while gas pipelines must function above or to the right of it.

FIGURE C: PHASE DIAGRAM OF A MIXTURE



The temperature and pressure combinations that delineate the right and upper boundaries of the phase envelope are called dewpoints, marking the conditions at which droplets first begin to appear in a vapor as the temperature or pressure falls. The combinations along the left side of the phase envelope are called bubblepoints, marking the conditions at which bubbles of vapor first appear in a liquid. TAPS engineers, therefore, worry about bubblepoints, while ANGTS engineers fret over dewpoints. The next chapter will examine how engineers use phase diagrams to determine what mixtures of light hydrocarbons can be handled safely in ANGTS.

THE RELATIONSHIP BETWEEN GAS COMPOSITION
AND UPSET CONDITIONS

While the choice of operating (or discharge) pressure has thus far dominated the discussion of two-phase flow, the operating pressure in itself does not limit the allowable range of gas mixtures. Likewise, the temperature at which gas is discharged from each compressor station is not the limiting factor. Instead, project engineers concern themselves with the combination of pressure and temperature conditions that would occur in a system upset.

As the term implies, upset conditions are those that occur when the system malfunctions. Engineers study upset conditions in order to forecast the most troubling combination of temperature and pressure (from the standpoint of two-phase flow) that vapors moving through the gas pipeline are likely to encounter. Since ANGTS will be designed to carry light hydrocarbons in a high pressure vapor phase (more precisely, a dense-phase fluid), upset conditions denote the LOWEST expected combinations of temperature and pressure.

How are upset conditions determined? First, the normal operating window of pressures and temperatures must be calculated. This represents the range of conditions likely to occur, assuming that the system is functioning properly. The lowest pressure experienced under these normal conditions is the suction pressure, which occurs at the entrance to each compressor station.

Calculating the lowest temperature likely to occur under normal operating conditions is more difficult. It depends, in part, upon the temperature at which gas is ejected from the compressor stations. Interestingly, the Canadian pipeline segments south of Whitehorse have an

advantage on this point. Compressor stations in Alaska must discharge gas with a temperature no higher than 32 degrees F., in order to prevent melting of permafrost through which the buried pipeline is laid. However, south of Whitehorse permafrost is a relatively minor problem and discharge temperatures, therefore, can be higher.

The lowest limit of acceptable gas temperatures is a function of the pipe's ductility and other physical characteristics. In the present preliminary design, this lower limit is -10 degrees F. Minimum normal operating temperatures are, in turn, determined mainly by the Joule-Thompson cooling effect: a gas naturally falls in temperature as it expands between its discharge from one compressor and its delivery to the next. The lowest operating temperature also depends upon what ground or air temperatures the designers expect to occur along the pipeline route. As long as the pipeline in Alaska is buried, the temperature it encounters will stay around 10 degrees F. throughout the year. If any section of the pipeline is constructed above ground, however, the cold Arctic winters become a real concern.

Once pipeline designers determine the normal operating window of temperatures and pressures, they can forecast the effects of specific malfunctions. Calculation of the resulting upset conditions reflects the designer's judgment as to WHICH malfunctions must be accommodated. Generally, upset conditions that have been discussed with respect to the Alaska gas pipeline reflect an assumption that the worst case would be one in which a single compressor station is totally shut down for repairs. But the implications of this assumption depend also on WHICH station is out of service. Moreover, the worst conditions under which the system will operate are also a function of how much the pipeline's designers and operators are prepared to reduce throughput in case of an upset: Will they simply route the

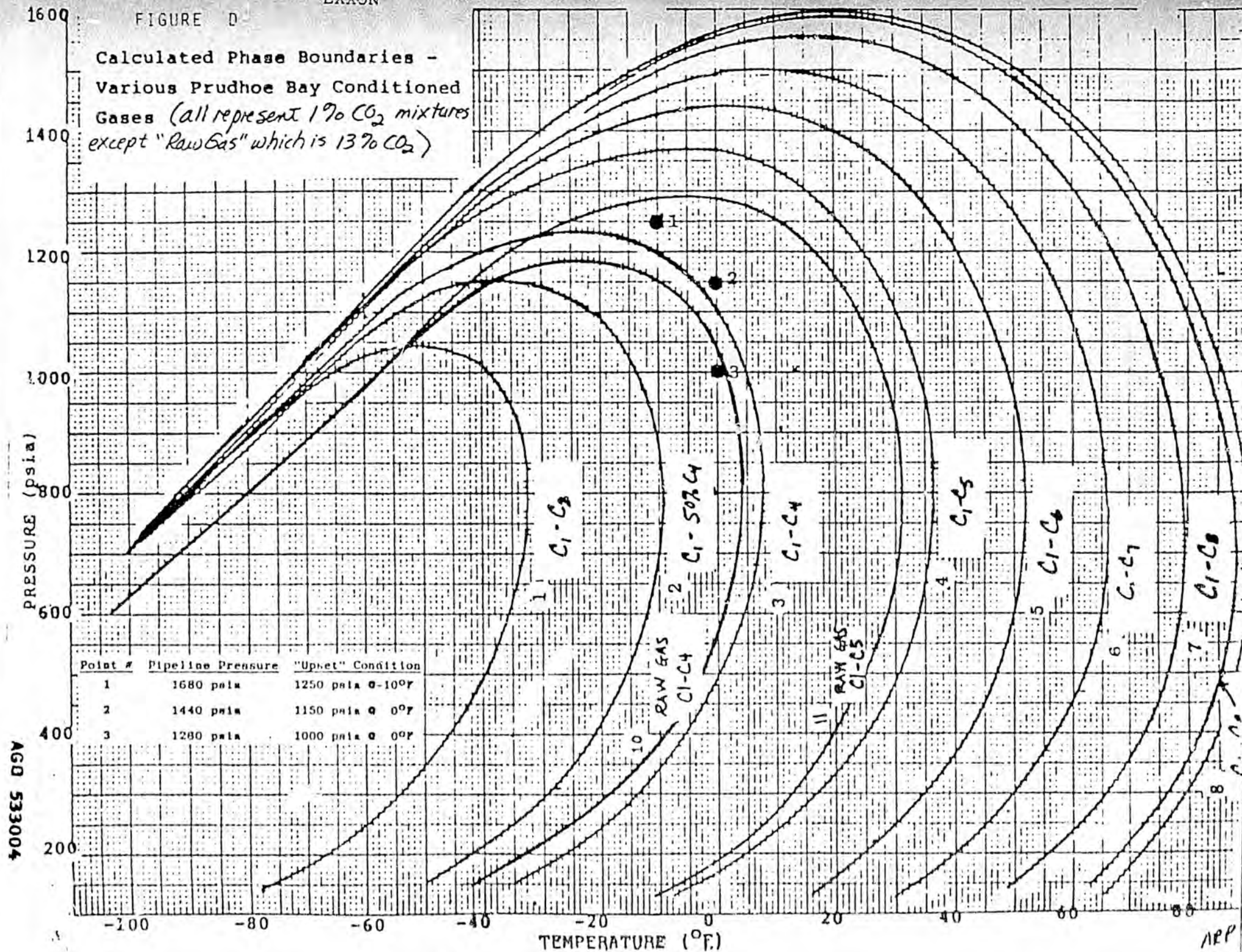
the gas past the ailing station without increasing the suction capability downstream? Or will the next station be forced to work harder in an attempt to keep throughput from falling too severely? Again, determining how much the operator can manipulate suction pressure at the downstream station depends upon the minimum stress temperature of the steel pipe (-10 degrees F, as we mentioned previously), the mechanical limitations of the machinery, and the dewpoint characteristics of the gas itself.

Figure D plots the temperatures and pressures of assumed upset conditions for the several pipeline operating pressures under consideration, and illustrates how close these points come to the two-phase flow conditions of various North Slope hydrocarbon mixtures. While an understanding of the basic physical principles reviewed here is important, no one can precisely assess the system's upset temperatures and pressures except in conjunction with detailed engineering and contingency plans. This explains why different parties have projected different upset conditions for ANGTS.

Figure D shows, for example, why upset conditions for the Canadian pipeline sections are of no real concern with respect to choice of gas composition. Even though the Canadian pipeline will function at a lower operating pressure (1080 psig, with a corresponding upset pressure of about 860 psig), it will have a significantly higher upset temperature (around 30 to 40 degrees F.) because the lack of permafrost south of Whitehorse permits higher compressor discharge temperatures. If one plots the intersection of 860 psig and 35 degrees F., it is evident that the design of the Alaska portion of the pipeline will be what limits the volume of intermediate hydrocarbons shipped through the entire system.

FIGURE D

Calculated Phase Boundaries -
Various Prudhoe Bay Conditioned
Gases (all represent 1% CO_2 mixtures
except "Raw Gas" which is 13% CO_2)



EXXON

VARIOUS FRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

Component	Unconditioned Separator Off-Gas	① C ₁ -C ₃	② C ₁ -50XC ₄	③ C ₁ -C ₄	④ C ₁ -C ₅	⑤ C ₁ -C ₆	⑥ C ₁ -C ₇	⑦ C ₁ -C ₈	⑧ C ₁ -C ₈	⑨ C ₁ -C ₉	⑩ Off-Gas C ₁ -C ₄
N ₂	0.484	0.564	0.559	0.554	0.551	0.550	0.549	0.549	0.549	0.549	0.488
CO ₂	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	12.773
C ₁	74.706	87.053	86.296	85.554	84.964	84.818	84.742	84.695	84.679	84.676	75.382
C ₂	6.428	7.491	7.426	7.362	7.311	7.299	7.292	7.288	7.287	7.287	6.486
C ₃	3.340	3.892	3.859	3.826	3.799	3.793	3.789	3.787	3.786	3.786	3.370
i-C ₄	0.450	--	0.260	0.515	0.512	0.511	0.511	0.510	0.510	0.510	0.454
n-C ₄	1.038	--	0.600	1.189	1.181	1.179	1.178	1.177	1.177	1.177	1.04
i-C ₅	0.217	--	--	--	0.247	0.247	0.246	0.246	0.246	0.246	--
n-C ₅	0.383	--	--	--	0.435	0.435	0.434	0.434	0.434	0.434	--
C ₆	0.148	--	--	--	--	0.168	0.168	0.168	0.168	0.168	--
C ₇	0.081	--	--	--	--	--	0.091	0.092	0.092	0.092	--
C ₈	0.047	--	--	--	--	--	--	0.054	0.054	0.054	--
C ₉	0.016	--	--	--	--	--	--	--	0.018	0.018	--
C ₁₀	0.003	--	--	--	--	--	--	--	--	0.003	--
Molecular Wt.	22.7	18.5	18.8	19.2	19.5	19.7	19.8	19.8	19.8	19.9	22.2
Heating Value (Btu/cf*)	1027	1095	1113	1131	1150	1156	1160	1163	1164	1164	996

*Gross, Wet, Actual @ 60°F., 14.73 psia

3-7-78

Alaska state officials thus far have argued that decisions regarding pipeline design and gas composition should not preclude shipment of intermediate hydrocarbons such as butanes. (This position will be discussed in more detail later.) However, when the time comes to develop firm contingency plans for upset conditions, the State's interest in shipping intermediate hydrocarbons through the gas pipeline may well be surpassed by its likely --- and conflicting --- interest in maintaining high throughput levels: As the preceding discussion shows, in the event of upset, maintenance of throughput depends on an ability to reduce the suction pressure at the next compressor station, which in turn is partly limited by the proportion of intermediate hydrocarbons in the gas stream.

D. CARBON DIOXIDE CONTENT

Produced gas from the field (sometimes called raw gas) contains about 13 percent carbon dioxide (CO_2). Whether that amount is allowed to remain in the pipeline quality gas, or is removed via conditioning³ down to a 1 percent or 3 percent level, depends on several factors:

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- 3) Some parties with an interest in ANGTS have used the words "gas conditioning" and "gas processing" interchangeably; and in many Lower 48 producing areas, the boundary between the two stages of natural gas treatment is hard to define. With respect to Prudhoe Bay natural gas, these two phrases have distinct regulatory definitions, which may result in very real differences in the price the law allows gas producers to receive. As a result, the producers are easily aggrieved by any "misuse" of the two terms. We will make no attempt here at a rigorous distinction between gas processing and conditioning; the reader should simply be aware of the sensitivity of this matter.

1. The effect of carbon dioxide on hydrocarbon dew-point. Figure D shows that a 13 percent CO₂ mixture enables the introduction of greater quantities of heavy hydrocarbons than would be safe with a 1 percent CO₂ mixture, but the effect is really rather small. Instead, the choice of CO₂ concentration must be made on other grounds.

2. The effect of carbon dioxide on pipeline corrosion. Under certain conditions, carbon dioxide will combine with water to form carbonic acid. If present in the sales gas stream, carbonic acid will corrode the steel walls of the pipeline. The question, then, is how various concentrations of CO₂ affect the risk that carbonic acid will seriously damage the pipeline during the twenty-plus years of gas shipments.

The producers collectively argue that carbonic acid corrosion in the Alaskan section of the gas pipeline is a false issue, in part, because it takes two to tango. Carbon dioxide in any concentration cannot turn into carbonic acid except in the presence of "free" water (water that condenses out of the vapor phase). Since enough water must be removed to meet WATER dewpoint specifications of -35 degrees F. for the section of pipeline in Alaska, no problem should ensue unless the temperature within the pipeline falls below that point; but the HYDROCARBON dewpoint specification will have to be much higher --- somewhere around 0 degrees F. in order to maximize shipment of intermediate hydrocarbons. Thus, before carbonic acid formation could pose a serious threat to the pipeline, hydrocarbons present in two-phase flow conditions would already have made the system inoperative.

Northwest Pipeline Company counters the producers' arguments with a different concern from its own standpoint as pipeline operator. While the sales gas containing more than 1 percent CO_2 may indeed ENTER the pipeline at Prudhoe Bay in a dehydrated condition that poses no threat of corrosion, the pipeline operator must ensure that the gas REMAINS corrosion-free throughout the several thousand miles of its journey. Apparently, some water is expected to contaminate the sales gas not only as a result of upset conditions, but even during hydro-testing associated with pipeline start-up. Whether Northwest's demand for a 1 percent CO_2 specification, therefore, is reasonable, has not yet been decided by FERC.

Because of permafrost problems in Alaska, the temperature of the gas must be held below the freezing point of water. Hence, if any water drops out in Alaska, it will likely do so in the form of ice or more precisely, hydrates, which are like ice crystals but encapsulate molecules of light hydrocarbons or sulphur compounds within their structures. At the planned operating temperatures for the Alaska pipeline segment, free water will form hydrates at temperatures as high as 60 degrees F. But ice and hydrates, unlike water, cannot combine with CO_2 to form an acid. Instead of gradual corrosion, the presence of solids will present a more immediate problem: blockage of the pipeline and its valves.

The Canadian section of the pipeline poses, perhaps, an even more fundamental concern. Canadian regulators have given preliminary approval to a water dewpoint specification for gas added to pipeline sections south of Whitehorse that is less stringent than specifications proposed for the

Alaska section. This difference, however, does not indicate any malfeasance by Canadian pipeline owners and regulators, but rather a difference in judgment about what constitutes acceptable risks in the face of added costs for prevention.

3. The effect of carbon-dioxide on downstream gas systems. Purchasers of Prudhoe Bay gas have argued that a high CO₂ content would adversely affect their interests in several ways.

In its July 1979 comments to FERC, the Natural Gas Pipeline Company of America states that a gas of 13 percent CO₂ would create corrosion problems within its own pipeline system, because that system's low-CO₂ gas from other sources has a relatively high water content. In addition, if Alaska gas contained excessive amounts of CO₂, it would have to be mixed with large quantities of gas from elsewhere in order to ensure consistent burning characteristics.

Northern Natural Gas Company in its letter to the Alaskan Gas Project Office of FERC (dated December 7, 1978), advocates even more stringent CO₂ standards. It claims that its purchased volumes of Alaska gas will first be stored as LNG and, as such, cannot tolerate a CO₂ content that exceeds about 200 parts per million (ppm). But as the State of Alaska observed in its reply comment of June 1979, all pipeline gas must undergo CO₂ removal at the LNG plant site. The State concluded, therefore, that Northern's concern should not influence the choice of CO₂ specifications for North Slope gas.

The valid point raised by Northern, however, was that most LNG facilities are now designed to treat pipeline gas whose CO₂ content does not exceed 1 percent. Hence, the additional expense that shippers must bear to treat 3 percent CO₂ gas must be taken into account in assessing the conditioning and transportation costs for Prudhoe Bay gas.

4. The effect of carbon dioxide on project economics.

One other area of concern has entered the debate on CO₂ specifications --- overall project economics. How would different CO₂ levels affect the cost of conditioning versus the cost of pipeline transportation?

The Ralph M. Parsons Company (in its February 1979 CO₂ specification study⁴) estimates that by relaxing the CO₂ removal process to yield a sales gas of 3 percent CO₂ instead of 1 percent, the conditioning plant construction costs could be pared down by about 7 percent. If no CO₂ removal facilities were built (yielding a sales gas of 13 percent CO₂), construction costs would be about half as much. Fuel requirements for the scaled-down conditioning plant would decrease by 8 percent in the 3 percent CO₂ case, and would drop by about one-third in the 13 percent case.

TABLE 5

<u>COSTS OF CONDITIONING</u>	<u>1% CO₂ (base case)</u>	<u>3% CO₂</u>	<u>13% CO₂</u>
Construction cost	100%	93%	54%
Fuel requirements	100%	92%	66%

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- 4) The Ralph M. Parsons' studies of conditioning processes and facilities were financed jointly by the North Slope producers and a half dozen likely gas shippers (interstate gas transmission companies). It was conducted about two years ago and, necessarily, had to adopt some working assumptions in spite of the many unknowns. Consequently these assumptions and the study conclusions are not totally satisfactory to all of the sponsoring parties. The study is, however, the only in-depth analysis that presently exists; and it is, therefore, widely quoted.

Table 5 suggests that from the standpoint of conditioning costs and fuel requirements on the North Slope alone, the 13 percent CO₂ case is a clear winner. One must remember, however, that such high CO₂ levels would impose greater transportation costs, additional capital costs downstream (since CO₂ must be removed prior to customer distribution), and it threatens pipeline corrosion. The table also shows that a 3 percent CO₂ specification is preferable to one percent, but not overwhelmingly so.

On the other hand, Northwest Alaskan Pipeline Company in its February 1979 "CO₂ Transportation Study", shows that a 3 percent or 13 percent CO₂ specification would cost MORE than a 1 percent specification from the standpoint of pipeline transportation costs. (While the added volume of CO₂ contributes no additional heating value to the gas stream, it does require an increased investment in compression equipment and more fuel during pipeline operations.) But here too, the cost differences between the 1 and 3 percent CO₂ specifications are not very substantial.

In comparing how much money would be SAVED in the conditioning process by moving from a 1 percent CO₂ specification to 3 percent, versus how much additional money and fuel would be SPENT for pipeline transportation, even Northwest admits that the conditioning cost savings are of greater importance [p 5. of Northwest's "CO₂ Transportation Study"]. The difficulty for FERC will be in judging the significance of this net cost savings compared to the pipeline corrosion and downstream marketing problems previously discussed. FERC has, at least for the present, ruled that the cost of reducing CO₂ content below 3 percent, if required, is to be treated as a conditioning cost. Until the issue of conditioning cost allocation is finally decided, however, we cannot know whether it is the producers (and the State of Alaska) or the gas consumers who would benefit from an attempt to optimize total project costs.

E. VOLUMES OF GAS AND GAS LIQUIDS AVAILABLE FOR SHIPMENT

No intelligent discussion about sales gas composition can take place without some agreement as to what volumes and kinds of hydrocarbons will actually be AVAILABLE for shipment through the gas pipeline. Previous debate on the matter of gas composition has, in fact, been clouded by differing outlooks on gas availability. Worse yet, those discrepancies in underlying assumptions have largely been overlooked. Again, whether all the intermediate hydrocarbons will be ALLOWED to enter the gas pipeline for shipment is a complex question with which the rest of this report is concerned --- but that is all the more reason to make sure that hidden differences in assumptions about hydrocarbon availability are not ultimately responsible for disagreements on other matters.

This section will examine the three factors that determine how much and what kind of hydrocarbons are available for shipment through the gas pipeline: (1) reservoir production rates, (2) North Slope fuel requirements, and (3) the ability of the TAPS oil pipeline to carry intermediate hydrocarbons.

1. Reservoir production rates.

The field rules for the Prudhoe Bay reservoir currently limit raw gas production to 2.7 bcf per day, and it is expected that this rate can be maintained for 25 or more years. This rate, in turn, will yield about 2.0 bcf per day of conditioned gas. No one, of course, can guarantee that such offtake levels will indeed be physically possible, or that Alaska's Oil and Gas Conservation Commission will approve them throughout the life of the field, because

the reservoir's production capabilities are based on predictions of FUTURE performance; but no one is now arguing seriously that any other figure makes more sense from the standpoint of today's planning needs.

2. Gas composition changes.

The expected hydrocarbon composition of that steady 2.7 bcf per day, however, IS expected to change through time. During the early years of gas sales, solution gas bubbling out of the crude oil will comprise the greater portion of total gas volume. But as crude oil production drops off, so will the volume of solution gas. The 2.7 bcf per day, instead, will increasingly consist of gas that comes directly out of the gas cap. Since gas cap gas is "leaner" in heavier hydrocarbons than the solution gas, the combined gas mixture, as well, will grow leaner through time.

ARCO [Dickinson letter to Tussing; January 3, 1980] estimates that by the 25th year of gas offtake, the natural gas liquids (NGL) content of the produced gas will have dropped by about 17 percent. Similarly, SOHIO [Pritchard letter to Barlow; January 23, 1980] estimates a drop-off in the ethane-propane NGL component of roughly 20 percent. The crucial issue is not, however, the absolute volumes of NGL's that must transit TAPS, but the PROPORTION of butanes in the oil stream, a ratio that promises to increase over time as oil production declines. It is nevertheless doubtful whether this trend is significant enough to merit any real consideration in system planning and design --- especially given the likelihood that during the 25 year operating period other gas reservoirs with different gas compositions will be tapped.

While the changing hydrocarbon content of PRUDHOE BAY natural gas may not be a major consideration in the design of ANGTS, system engineers do have to take into account the likelihood that gas produced from other, still undiscovered or undeveloped reservoirs on the North Slope may differ significantly in chemical composition. Prudhoe Bay gas is relatively sweet and wet (low in sulfur compounds and rich in NGL's), and has a relatively high CO₂ content. A conditioning plant designed to treat this raw gas stream, or a pipeline designed to carry it, would be uneconomic or even inoperable for gas from another reservoir which happened, for example, to be sour and dry, and contained little CO₂.

Under the present plan for ANGTS, the initial conditioning plant will be located on the North Slope and designed expressly to treat the volume and mixture of compounds the Prudhoe Bay reservoir is expected to produce. If new and different gas mixtures later came on stream from other reservoirs, the existing plant could be modified or new facilities added at the same place or elsewhere specifically to accommodate the new supply. In either case, the pipeline itself can be built to accommodate pipeline-quality (fully-conditioned) gas from any source in Arctic Alaska. If the conditioning plant were at Fairbanks or further downstream on the pipeline, however, system engineers would face the far more difficult task of designing both the pipeline and the conditioning plant to handle a stream of raw gas whose characteristics might change radically over time.

Thus, the possible need for ANGTS to handle different (and yet unknown) gas mixtures over its operating life is one reason why the gas producers, Northwest Alaskan, the prospective gas shippers, and FERC all seem to agree that the conditioning plant for Prudhoe Bay gas should be located on the North Slope, despite the belief of many Alaskans that construction and operating costs would be less, and local economic benefits greater, in an Interior Alaska location.

3. North Slope fuel requirements.

It takes a good deal of energy to produce, clean and condition, and transport oil and gas from the North Slope. This energy must be drawn out of the stream of produced hydrocarbons. There are three general categories of North Slope fuel uses: (1) FIELD FUEL, (2) TAPS FUEL, and (3) PLANT FUEL (for the gas conditioning plant).

(1) FIELD FUEL is needed for all of the activities relating to oil and gas PRODUCTION. In addition to actual oil production at the wells, energy is consumed in gathering the oil into facilities where the crude can be separated from the solution gas, dehydrated of its water content, and cleaned of its impurities. Field fuel is also consumed by the Prudhoe Bay electric generating plant. Produced gas in excess of fuel requirements is currently compressed to about 4000 psi for reinjection into the reservoir, pending the onset of gas sales. This function is performed in the Central Compressor Plant, which, likewise, requires a a good deal of energy.

Estimates of future field fuel requirements, such as those used in the Ralph M. Parsons Company report, must also provide for additional production activities, which will include more elaborate facilities for injecting back into the reservoir the produced water that is separated from the crude, and for the injection of source water from the Beaufort Sea in order to maintain reservoir pressure. (This is sometimes called waterflooding.) The "maximum" field fuel case used in the Parsons report takes all of these activities into account.

(2) TAPS FUEL is that which is needed to run the first four pump stations of the Trans-Alaska oil pipeline. While pump stations south of Station #4 provide for their own fuel

requirements by processing a portion of the crude oil into diesel fuel in individual topping plants, the TAPS owners decided that it would be cheaper to supply the more northerly pump stations with North Slope gas by means of a buried gas pipeline beside the oil line. Unlike the TAPS oil pipeline, the Alaska Highway gas pipeline will transport a mixture of hydrocarbons that can be used directly in its compressor stations, thus no provision has been made for supplying even its northern portions with a separate energy stream.

(3) PLANT FUEL is needed for all aspects of the gas conditioning process --- for (a) separating and fractionating propanes, butanes, and pentanes-plus from the lighter hydrocarbons; (b) for removing carbon dioxide from the remaining methane-ethane stream; and (c) for chilling and compressing the conditioned gas to meet the requirements for shipment through the gas pipeline. Sometimes PLANT FUEL is discussed more specifically as HEATER FUEL and TURBINE FUEL. The distinction is made because while heaters can run on a relatively low BTU fuel, turbines have more stringent requirements.

Where does all this fuel come from? Currently, the Field Fuel Gas Unit conditions a portion of the raw gas to provide energy for most ongoing field activities and for TAPS.⁵ Since the TAPS fuel gas line experiences extremely cold temperatures enroute to the pump stations, the Field Fuel Gas Unit yields a gas stream with exceptionally stringent specifications --- a -40 degree F. hydrocarbon dewpoint and a -60 degree F. water dewpoint. When waterflooding begins, the Field Fuel Gas Unit can be expanded to

5) The gathering centers in the western part of the field furnish their own fuel.

accommodate the new demand. Or, as the Parsons study anticipates, additional FIELD FUEL requirements can be met by fuel generated at the conditioning plant. The Parsons study has chosen the latter technique in an attempt to optimize the entire system, disregarding ownership responsibilities. In so doing, an outlet is found for the ethane-rich CO₂ "waste" gas that is a by-product of the CO₂ removal process selected by Parsons. This stream is enriched with propane to provide a fuel suitable for field activities.⁶

Nevertheless, the producers make a point of emphasizing that they have several options for taking care of all their own fuel needs in the field and for TAPS, and they have not yet decided whether it would be in their interest to enter into an arrangement with the owner of the conditioning plant (whoever that may be) simply for the sake of overall project optimization. After all, their gas sales contracts commit for sale only the gas that is EXCESS to field and TAPS requirements. The producers further stress the potential disadvantages of making their crude oil production, processing, and transportation facilities dependent upon a stream of by-products from the gas conditioning plant. This concern would probably be even greater if the conditioning plant were operated and controlled by another party, such as the state.

Of course, the PLANT FUEL requirements will have to be met by the owners of the conditioning plant. Parsons Company, in its proposed plant design, has selected what it

6) No one knows exactly how much field and TAPS fuel will be needed in the future. Moreover, those requirements will vary almost daily. Parsons, therefore, calculated both a "maximum" and a "minimum" field fuel case. Most parties believe the "maximum" case data is the more relevant for planning.

considers to be the most economical CO₂ removal process, given the raw gas composition and the probable gas pipeline specifications. The process chosen by Parsons, however, results in a waste gas that also contains about half of the ethane that enters the plant.⁷ Accordingly, Parsons recommends using the ethane-CO₂ by-product for fuel. Given the fact that SOMETHING has to be burned as fuel, this is not necessarily a bad thing --- unless there is some reason to view the ethane (and the propane that enriches it) as exceptionally valuable hydrocarbons for which a better use exists. There is little argument within Alaska that ethane would be the most desirable feedstock for a local petrochemical industry. It is still unclear, however, whether an ethane based petrochemical plant is economically feasible in Alaska, and even if it were, whether all of the ethane would, in fact, be required for such a facility. For example, the November 1979 study prepared by Bonner & Moore Associates for the State of Alaska indicates that only about one-fourth of the ethane is needed to feed a "world-scale" petrochemical plant, in which case, the CO₂ removal process chosen by Parsons Company in itself should cause no alarm.⁸

One other major point of controversy arises with respect to design of the CO₂ removal process and PLANT FUEL requirements. The ethane-rich CO₂ waste gas has a lower heating value (net BTU) of about 200 to 220 BTU per cubic foot. While this mixture may be adequate for use in

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- 7) The Parsons design absorbs CO₂ via a physical, rather than a chemical, process. This process is much like fractionation in that the components are separated by their different boiling points. Given that the boiling point of ethane is relatively close to that of CO₂ (see Table 3), some of the ethane necessarily will "flash" off with the CO₂.
 - 8) Bonner and Moore Associates, Inc., Promotion and development of the Petrochemical Industry in Alaska (November 1, 1979). See also the author's critical review of the Bonner and Moore report, "Prudhoe Bay Natural Gas Liquids, the Alaska Highway Gas Pipeline, and Petrochemical Development in Alaska" (January 20, 1980).

the plant heaters, it must be enriched to meet the specifications of the local turbines and field equipment. The Parsons Company design raises the BTU content by propane "spiking" to achieve a net heating value of about 475 BTU/cf for local turbine fuel, and 825 BTU/cf to suit the design limitations of existing field equipment. The controversy lies in the fact that while propane can easily be shipped south in the gas pipeline, butanes are more troublesome. Therefore, wouldn't it make more sense to use butane rather than propane for spiking purposes?

Unfortunately, the answer is not so simple. Butane could create the same hazards in the fuel system that it poses in the Alaska Highway gas pipeline --- condensation at low temperatures. In addition, its burning characteristics are different from those of propane, because it packs a bigger wallop of combustible carbons in each molecule. While use of butane instead of propane is not entirely out of the question, those responsible for smooth operations on the North Slope naturally will look for system designs and fuel compositions that promote simplicity and reliability. Unless the State of Alaska can demonstrate a special interest in the propanes or butanes that differs markedly from that shared by the other gas owners, any second-guesses the State might make with respect to fuel enrichment decisions would probably be viewed by others as unduly meddlesome.

Table 6 provides a perspective on North Slope fuel consumption. Of the hydrocarbons in the raw gas stream, about 15 percent will be consumed as field fuel, by the TAPS pump stations, and during the conditioning process.