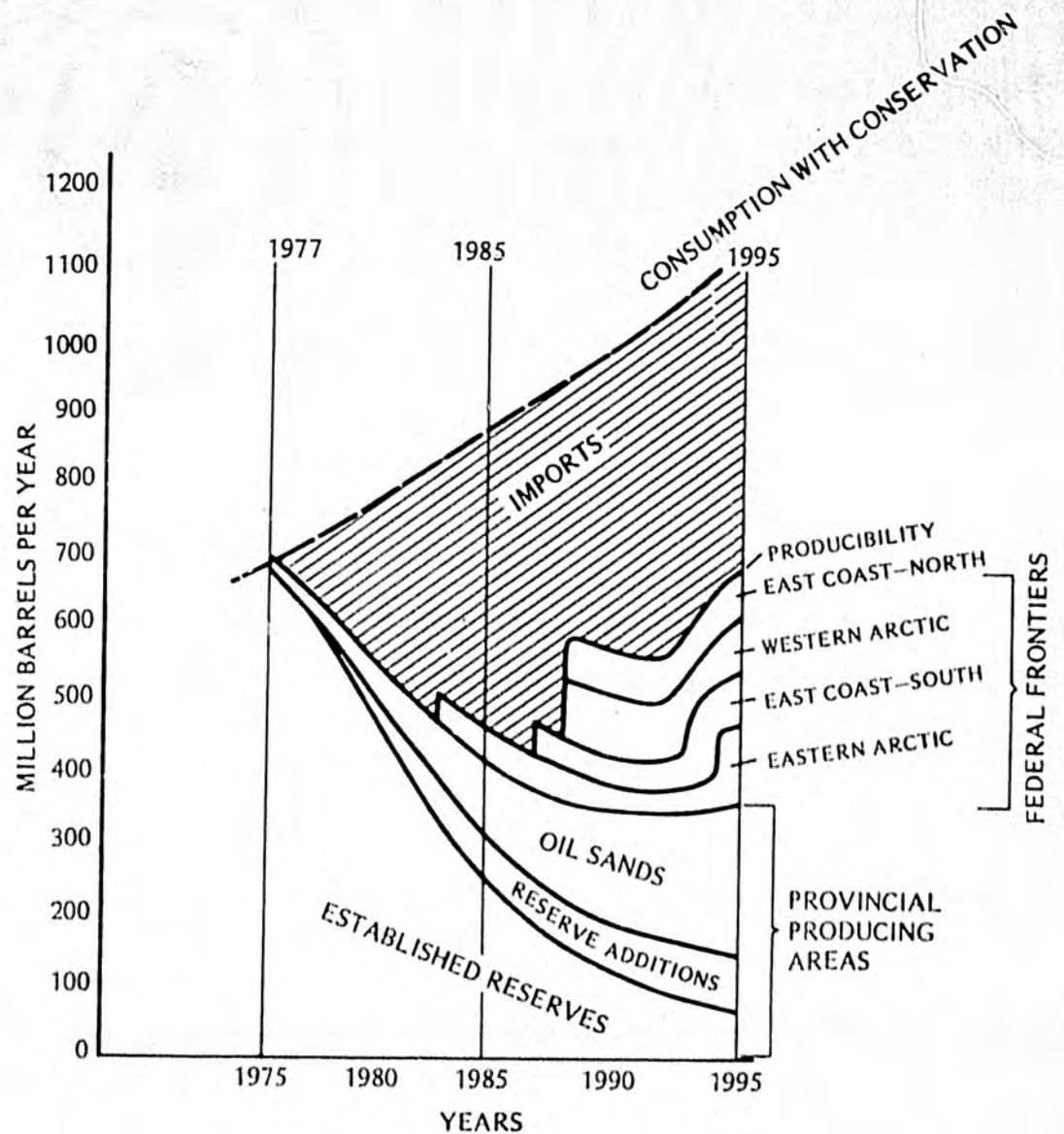


ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

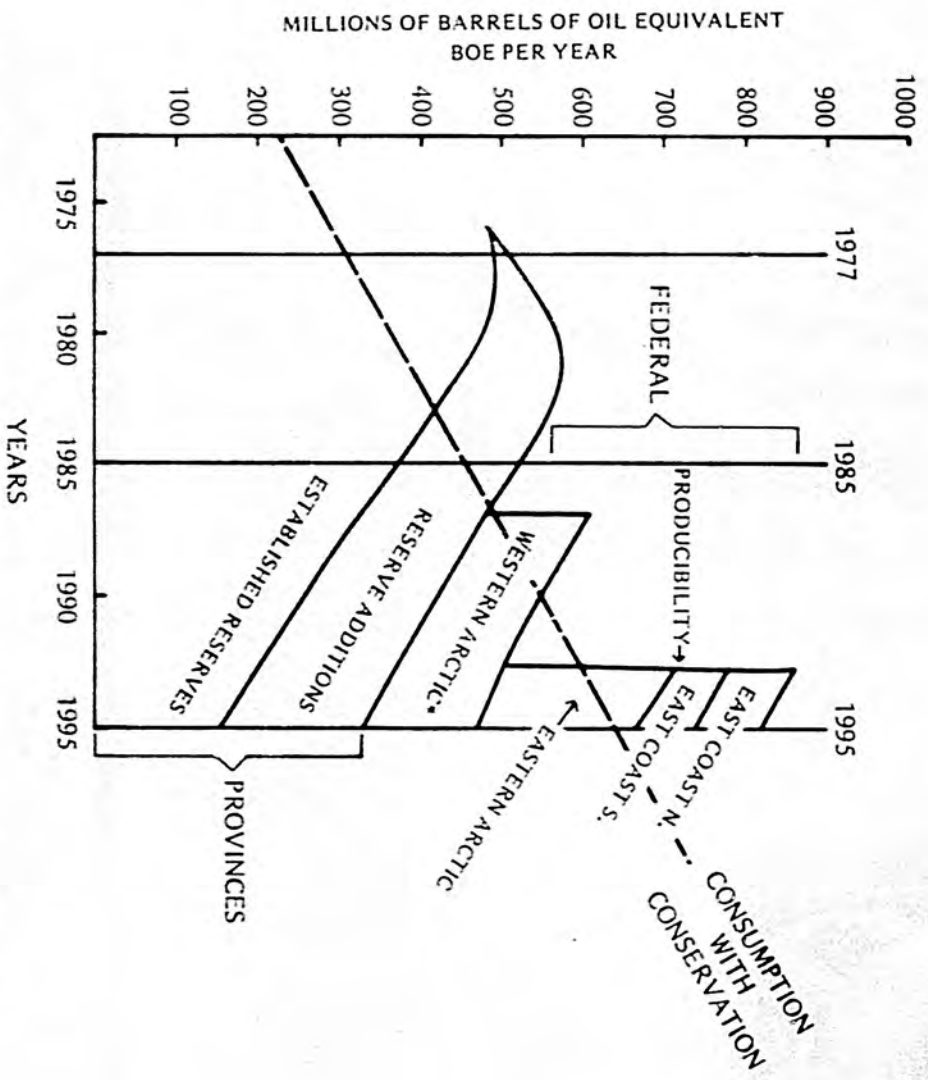
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EXHIBIT 1



NOTE: Exhibit 1 and 2 are not forecasts of the amount of oil and gas that Canada is likely to produce between now and 1995: rather, they are projections of what might be obtained from the maximum exploration and development effort that we are realistically capable of mounting between now and 1985, and effort that would require changes in our present policies.

EXHIBIT 2



* FROM ALL CANADIAN RESERVES (A JOINT U.S. CANADIAN LINE COULD BE EARLIER)
SOURCE: Exhibit 1 and 2 derived from Appendix D.

Chairman

R. D. Brown, B.Comm, M.A., F.C.A. Senior Tax Partner, Price Waterhouse & Co.; Member of Taxation Advisory Committee, Department of National Revenue; former Co-Chairman of Joint Committee of Taxation of the Canadian Bar Association and the Canadian Institute of Chartered Accountants; special lecturer in advanced income taxes at Osgoode Hall Law School.

E. P. Chapman, Jr., P.Eng. Consulting Minerals Engineer, Vancouver; formerly President and Director of Chapman, Wood & Griswold Ltd.; member of National Committee on Mining.

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The Honourable E.C. Manning, P.C., C.C., L.L.D., D.U.C. President, M & M Systems Research Ltd., Edmonton; member, Senate of Canada, Ottawa; former Premier of Alberta, 1943-1968.

A. E. Pallister, B.Sc., P.Geoph. President, Pallister Resource Management Ltd., Calgary; Former Vice Chairman of Science Council of Canada; Past President, Canadian Society of Petroleum Geologists.

D. D. Peters, B.Comm., Ph.D. Vice President and Chief Economist, The Toronto Dominion Bank, Toronto; Participant in economic and industry conferences, and a writer on economic subjects.

L. A. Thorssen, B.Sc., M.A., D.U.C., P.Eng. Executive Director, Canada West Foundation, Calgary; Former Chairman, Alberta Universities Commission; former Administrative Head of Department of Civil Engineering, University of Alberta.

DESCRIPTION DE LA CONFERENCE DE PRESSE DU PREMIER MINISTRE
AU CERCLE NATIONAL DE LA PRESSE, A WASHINGTON,
LE 23 FEVRIER 1977

TRANSCRIPT OF THE PRIME MINISTER'S PRESS CONFERENCE
AT THE NATIONAL PRESS CLUB, IN WASHINGTON,
FEBRUARY 23, 1977

Q: Paul Racine. Monsieur le Premier ministre, vous avez proposé, dans votre discours au Congrès hier, la possibilité de modifier la Constitution canadienne. Vous en avez déjà parlé à quelques reprises ces dernières semaines, mais, comme en ce moment au Québec, il y a un gouvernement qui est intéressé à toute autre chose ... (inaudible).

R: Cela dépendra un peu des premiers ministres des provinces. Ce que j'ai voulu indiquer et répéter hier, c'est que le Gouvernement fédéral, quant à lui, est prêt à reprendre les discussions constitutionnelles que nous avons entreprises en 1968, jusqu'en 1971. Evidemment, si les provinces ne sont pas intéressées, nous ne les forcerons pas à engager le débat constitutionnel, mais je crois que les Canadiens en général s'y intéressent d'une façon plus vigoureuse et il est possible que nous acceptions de discuter la question avec des groupes de citoyens, mais notre préférence, bien sûr, ce serait d'avoir des conférences fédérales-provinciales sur le sujet constitutionnel. Encore une fois, il ne s'agit pas de forcer la note ou de brusquer les choses, seulement si les provinces le désirent.

Q: Mr. Prime Minister, have you discussed with the President or will you discuss with the President the Arctic Gas pipeline proposal and what is your position on that?

A: Well, we discussed not particularly that proposal, the Arctic Gas one, but we looked at the various alternatives including the Alcan route. There was a great interest on the part of the President of our attitude with regard to pipelines. I was as forthright as I could be within the strictures of the present situation. Canadians generally and certainly our government want to be as helpful to the Americans as we can in this particular aspect. That is what our visit is all about. That is what friendship is all about

- 2 -

and, after all, there is American gas to American consumers and we don't want to be dogs in the manger about it.

I reminded the President, as he knew I am sure, that we have pipelines through the United States servicing Canadian territory and other things being equal we want to be as forthcoming with the Americans. The President knows that there are some problems which have to be solved which are also familiar to Americans: environmental problems and native rights problems and rather complicated economic consequences of a vast injection of capital into Canada, investment capital into Canada and these are problems which are being studied now by the National Energy Board and by a Royal Commission headed by Judge Berger. Until these reports are received, the government will not be even legally in a position to accept or reject any proposition. Our National Energy Board has to make a recommendation on proposals before that Board before the government can act and we are expecting these reports in the first half of this year.

Q: Mr. Prime Minister, we were told that after reading your speech, President Carter asked for a briefing on the Quebec situation and that you then discussed privately for about ten minutes. Can you tell us the kind of response you got from him? Did he express a concern on the possible secession of Quebec?

A: He expressed interest in my views on the situation in Canada in general and Quebec in particular, but was not particularly volunteering any American point of view beyond the very general statements that he has made publicly. Naturally the Americans are looking to the north as a country with stability and duration and I think they are properly sensitive about interfering into our internal political problems and that seems to characterize the attitude of the President.

It was quite clear that if asked a preference the Administration would prefer to see a strong united Canada but beyond that, and I think quite properly, they are not expressing a point of view; just expressing interest.

A: Well, it is kind of technical but a simple way of saying it is that an interim agreement was reached because of the imminence of the 200-mile limit adopted by the Americans. I think the deadline was the 1st of March. We brought it in on the 1st of January. We had very few days to make sure that there wouldn't be a cod war between us and very positive results were obtained in every area except one and the positive results were that we would forbear at least until the end of this year and regardless of our new proclamation of a 200-mile limit we would continue more or less with the status quo anti while the two administrations worked toward a more accurate definition of the line on the east coast or some way of ascertaining what that line should be and the same thing on the west coast. There was one area of difficulty which had not been solved and that was the area of salmon fishing on the west coast and yesterday after a great deal of work on the part of our ambassadors and officials and ministers (and I think with some pressure from the President and myself) accommodation was reached also on the salmon. It is essentially an interim agreement to forbear and not to insist on imposing each of our theses on the other before the 1st of March. In other words, not to start throwing the other person out of one's waters just because the problem hasn't been solved.

(Q: Mr. Prime Minister, regarding a possible pipeline route to Canada, you mentioned the issues of the environment and the native claims. Do you anticipate that those can be settled so that your government could make a final decision within, say one year, or is it likely to be longer than one year before Canada gives a definite final answer?

| A: We realize we have to give you a final answer whatever it be before the end of the year. The President's deadlines (I believe the ultimate ones) will expire at the end of the geographical year and likely they will expire before so we realize that giving you no answer is an answer in a sense and if there is no pipeline to Canada I suppose there is the El Paso route which is the one that the Americans would go for. It is a very costly one for you and it has certain disadvantages.

Canada too and therefore we are ^{very} aware of the time strictures and we have to give you an answer at whatever deadline the President feels he has. Likely one in September. There will be an answer and I hope it will be in line with the friendship of our country and one which is to the advantage of both countries.

Q: Mr. Prime Minister, a moment ago in answer to Doug Small's question about the choice, you mentioned that Canadians will have to make a mature choice in respect to the accommodation of the Quebec problem. Presumably on the understanding that you cannot convince Quebec to stay in unless the rest of Canada / ^{wants Quebec} to stay in, how and when will Canadians be asked to and be able to make that mature choice? How will that be done?

A: I think essentially it will be shown in the understanding expressed by English Canada of the reality of the French fact.

I don't think any one event, for instance, or referendum will be needed to show that. I think a different attitude and different understanding towards either our policies as a Liberal government towards one Canada or policies of the Opposition which would be acceptable, too, would be the test of the public. I don't think we can ignore the question. I don't think we can continue to say, "Well, it is not going to happen and we can conduct ourselves as though separation wasn't even a remote possibility." I am really answering you that there is not going to be one event, to my knowledge, which will sort of crystallize the acceptance by English Canada of the French fact. If I had to signal any one event, it would be an event like the Air Traffic Controllers' or the Air Pilots' strike. If too many negative evidences of this kind are given to Quebecers that the French language is not acceptable to the rest of Canada even in Quebec air space, then I think we have begun seriously to lose the battle.

SCOMM

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State copy

Bill Lister

ANALYSIS OF TRANSPORTATION
PROPOSALS FOR NORTH
SLOPE NATURAL GAS

Report to State of Alaska
Office of the Attorney General

(Draft)
March 31, 1975

Arlon R. Tussing
Institute of Social, Economic
and Government Research

University of Alaska

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SUMMARY AND POLICY
CONCLUSIONS

1. There is serious doubt about the economic viability of either the El Paso or Arctic Gas proposal. Either is likely to result in transportation costs to the Lower 48 greater than the price at which the quantity of gas to be produced on the North Slope could be sold. One implication is a very low or possibly negative wellhead price.

2. Deregulation of the field prices of natural gas in interstate sales and rationalization of transmission company and gas distributor rate structures would further jeopardize the economic viability of either project by reducing the artificial "shortage" of natural gas now created by regulation.

3. Notwithstanding the foregoing, a policy of promoting U.S. energy self-sufficiency will probably lead the FPC (or Congress) to certify one prospect or the other somewhere down the line; however, the sponsors will later have to go to the Federal government (and perhaps to the State) for aid.

4. In view of the marginal economics of both systems, the lowest cost variant of one or the other is likely to be chosen. Additional costs (resulting, for example,

for a less than optimum routing) will have a powerful leverage effect on the wellhead price.

5. The Arctic Gas proposal appears to be the most economically advantageous from a national standpoint (or least disadvantageous, if the costs of either exceed its benefits). The overwhelming likelihood is for ultimate approval of this system, on political as well as economic grounds.

6. If the Arctic Gas proposal is approved, there seems to be no variation that would improve fuel costs or availability in Fairbanks (or elsewhere in the more densely populated areas of Alaska.) In this instance, the state's interest is solely in maximizing the netback value on which its royalty and production tax income is calculated. This interest is advanced best by minimizing construction and operating costs, and avoiding expensive add-ons to the system.

7. Gas from a Trans-Alaska pipeline would have costs at the burner tip in Fairbanks comparable to that of distillate fuel oil from the proposed refinery. Its availability would jeopardize that refinery's viability.

8. A Trans-Alaska gas pipeline, associated with a project to carry LNG to the West Coast, would provide the optimum transport system from the point of view of the state's revenues from Prudhoe Bay gas, if:

(a) the pipeline's owners (or the federal government) would take the financial risks for the system as a whole;

(b) the Trans-Alaska pipeline component were operated as a common carrier on a cost-of-service basis (as contemplated by El Paso); and

(c) industrial customers could be found for the state's royalty gas.

9. The state's choice between the two proposals also depends, of course, upon its evaluation of the construction impact of the pipeline project and of the socio-economic and environmental impact of ^{gas-}using industry, as well as upon the environmental implications of the transportation projects themselves.

10. In endorsing the concept of a Trans-Alaska gas pipeline, the state does not have to endorse the application of El Paso-Alaska, but might consider urging the FPC to direct that a broader, financially more competent entity (essentially the Arctic Gas group plus El Paso) construct the system.

11. In order to be able to take maximum advantage of opportunities for intrastate industrial gas sales, the state should amend its tax law to permit taking production taxes in kind, and should not prematurely sell or option its royalty gas.

Senate Copy

ARLON N. TUBBINS
5352 29TH STREET, NORTHWEST
WASHINGTON, D. C. 20015

May 26, 1976

The Honorable Chancy Croft
President, Alaska State Senate
Juneau, Alaska 99801

Dear Chancy:

The following is a personal account; in response to your request, of my own views on the merits of competing proposals for a transportation system to carry natural gas from Alaska's North Slope to markets in the Lower 48 states.

Over the last year I have devoted considerable attention to proposals for the transportation of natural gas from the North American Arctic to the population and industrial centers of the United States and Canada. During that time I arrived at evaluations of several major issues which were in some respects contradictory to the assumptions on which the major private interests and governmental authorities (U.S., Canadian and Alaskan) were proceeding.

I have of course taken for granted your acquaintance with:

- (1) The two principal transportation systems proposed to the Federal Power Commission before May 1975: El Paso-Alaska's "trans-Alaska" pipeline and LNG tanker system, and Arctic Gas' overland pipeline system across Canada which would also carry natural gas from the Mackenzie Delta to Canadian markets;
- (2) Foothills Pipeline's proposal for an all-Canadian, "Maple Leaf" pipeline to carry Mackenzie Delta gas;
- (3) The principal advantages and disadvantages argued for both proposals;

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(4) The rationale for the State of Alaska's endorsement of the El Paso system; and

(5) My own concern with the issue of transportation systems as a consultant to the State of Alaska and to the U.S. Senate Committee on Interior and Insular Affairs, and as a public member of Alaska's Royalty Oil and Gas Development Advisory Board.

I have, as you probably know, no financial stake in any of the proposals, nor have I had any business relationship with any of the systems' sponsors or participants.

From the time they were initially proposed, I have had serious questions about the viability of the transportation systems proposed by both Arctic Gas and El Paso for taking Alaska North Slope natural gas to Lower 48 markets. An investigation I conducted on the economics of the two proposals for a State of Alaska task force in early 1975 raised the possibility that the cost of delivering the gas might actually exceed its value to consumers. [Excerpts from my report are appended to this letter.] Subsequently I have become quite convinced that both projects as proposed by their sponsors are so risky that they could not be privately financed, even if their political and regulatory problems could be overcome -- itself a questionable issue.

Risk Factors

Both projects face the following risks:

(1) Gas supplies: production from the Alaska North Slope (and in the case of the Arctic Gas proposal) from the Mackenzie Delta may be substantially less than the design capacity of either transportation system, meaning that each unit actually carried would have to bear a larger portion of the system's fixed costs than projected by its sponsors.

(2) Delays and Capital cost overruns: Actual construction costs may exceed estimated costs by substantially more than the effect of general inflation. The Arctic Gas project would use a chilled gas pipeline concept untested in North America, while its route traverses hundreds of miles of difficult Arctic terrain where there has been no previous construction of either pipelines or roads. El Paso proposes a system of unprecedented pipeline pressures and a huge scale-up

of existing LNG technology. New technology, unfamiliar environments and a large scale relative to previous projects are exactly the ingredients for the most spectacular cost overruns. For these reasons I would not be surprised to see the total cost of either project exceed \$20 billion, including interest on funds used during construction. [See Appendix 2.]

(3) Market: Both El Paso and Arctic Gas insist that the natural gas shortage in the United States is an absolute one, and that Lower 48 markets will accept North Slope natural gas at any price. Not everyone agrees; the Federal Energy Administration, for example, estimates that no market for Prudhoe Bay gas would exist in 1985, at a "city gate" price exceeding \$2.40 per million BTU (in 1975 dollars). The Interior Department's study reaches a similar conclusion. This price could easily be exceeded even without implausibly large cost overruns or shortfalls in gas supplies to the system.

(4) Political, regulatory and other institutional issues: Each project would face serious political and legal obstacles, even after it received a certificate from the Federal Power Commission. Lack of coordination in U.S. and Canadian approvals, for example, could block or delay construction of the Arctic gas system, while there is some chance that resistance in California to port and terminal facilities would jeopardize completion of the El Paso system. The Arctic Gas system is, significantly, opposed by the governments and the preponderance of public opinion in both Alaska and Alberta, and the El Paso system is opposed by the state of California. The major environmentalist organizations are hostile to both projects. Neither they nor various local interest groups are likely to abandon every attempt to obstruct or delay construction simply because one system had been sanctioned by the Federal Power Commission.

Financing Problems

The financial consequences of the risks I have listed are magnified by the fact that neither project can be built in smaller self-sustaining stages. Either would be a large integrated system which could not carry any gas or produce any cash flow until it was completed. All the capital invested (\$10 to \$20 billion or more) would therefore be exposed to these risk factors for at least the entire planning and construction period.

Private lenders simply will not accept risks of this sort, and neither projects' sponsors are financially large enough to carry them, even if they were willing to do so. They do not in fact seem to be willing, as they both propose tariff conditions which would protect their own profits as well as their debt service obligations against "all events." Only the federal government and/or (perhaps) potential gas consumers are in a position to carry financial risks of the size associated with either of the systems.

Accordingly, El Paso proposes to use federal loan guarantees (under an existing program) for its LNG tankers, and spokesmen for Arctic Gas have suggested that government indemnify the sponsors against cost overruns exceeding 40 percent (nearly certain, in my judgment). But, more importantly, each applicant proposes to rely on "full cost of service all-events tariffs" to cover their debt service obligations and to assure a return on their equity. These tariffs provide, in brief, that consumers be required to pay the debt service and operating costs of the transportation system (plus a profit to the owners) no matter how great these costs are and whether or not the customers receive any gas. Arctic Gas' tariff would begin to run as soon as gas was first delivered; El Paso's would begin 60 months after approval of its project, even if it were never completed.

The proposition that consumers should bear or share in the risks associated with a project which benefits them is not in itself unreasonable, provided that the economic expectations of the project are clearly favorable and the risks of a reasonable magnitude. But with these projects there are good reasons for doubt on both scores. Moreover, even if the Federal Power Commission were to approve all events tariffs, local gas distributors would not sign contracts containing such tariffs unless they were assured in advance by their state regulatory commissions (as well as by their own market analyses) that they would be able to pass these charges through to their own customers. Responses by the state commissions to Federal Power Commission inquiries suggest that there is almost no chance that they would give such advance approval.

These considerations lead inexorably to the conclusion that neither system can be built without either substantial federal financial backing, Federal Power Commission authority to preempt the jurisdiction of state utility commissions over the tariffs of local distributors, or both. No plausible proposals

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of either sort have yet been made, either by the applicants or by any of the responsible federal agencies. Moreover, either project would be of questionable economic viability -- even if the question of who will bear the risk were resolved. In addition, there is still a significant possibility that either project could effectively be blocked or delayed indefinitely by legal or political obstructionism by its opponents.

In summary, there seem to be two problems that work together to make questionable the completion of either project as proposed: each of them requires too large an initial capital, and that capital would be exposed to too many large risks. Once these are recognized as the critical problems to be overcome, it is obviously worthwhile to investigate whether there might not be some alternative system (or modification of one of the applicants' systems) which could begin with a smaller investment and perhaps be expanded in stages after gas and income begin to flow, a system with a smaller potential for cost overruns, and one which would have fewer opponents on environmental, developmental or economic nationalist grounds.

Transportation of North Slope Gas as Methanol

As of the beginning of 1976, two proposals, neither of them in the form of applications to the Federal Power Commission, seemed to have some such potential. Firstly, a group of firms headed by the Westinghouse Oceanic Division have been advocating converting North Slope natural gas within Alaska into fuel grade methanol, which could be blended with motor gasoline, burned in combustion turbines, or used as chemical feedstock. Westinghouse's main interest in this system was in developing submarine tankers to haul the product, and its promotions seemed directed mainly at getting Maritime Administration funds for construction of a prototype tanker. Methanol could, however, also be transported in batches through the Trans-Alaska oil pipeline with conventional technology, and carried to ports elsewhere in the United States by conventional products tankers.

A methanol system would need no fixed transportation system of its own (other than additional storage tanks at both ends of the pipeline) until the oil pipeline reached full capacity, a date that seems to be steadily receding because of construction problems and the lack of transport facilities to move Alaska crude oil beyond the West Coast. Unlike the El Paso

and Arctic gas systems, which would require all the gas from the main Prudhoe Bay reservoir (at least 2 billion cubic feet per day, and perhaps more) to be even arguably feasible, the least-cost methanol conversion facility would require only 25-150 million cubic feet per day. One to three pilot conversion trains could be installed at an initial risk of perhaps a few hundred million dollars; there would thereafter be plenty of time to be sure of the amount of gas available, conversion and transport technologies, markets and the economics of the system before investment gradually (if ever) reached the many billions of dollars proposed for either of the gas pipeline systems.

Wentworth Brothers has proposed a complex variation on the methanol conversion concept that would use natural gas (including the natural gas liquids and carbon dioxide produced together with the methane, but which would otherwise have to be removed from the gas stream) together with coal to produce fuel grade methanol, which would then serve as the vehicle for a coal slurry. Significantly, however, Wentworth (like Westinghouse) has advanced its concept as a rationale for getting government research and development money, not as an immediately commercial practicality. The methanol concept need not be pursued further here, because if it indeed makes sense, there seems no reason why private enterprise cannot take the initiative and establish a pilot facility, without a guarantee of all the Prudhoe Bay gas, without a Federal Power Commission certificate of public necessity and convenience, and without federal or state financial assistance. [See my testimony for the Alaska Senate State Affairs Committee, which is appended to this letter.]

The Alaska Highway Route

The second system which seemed to have a possibility of meeting some of the criteria mentioned above would be an overland natural gas pipeline along the general route of the Trans-Alaska oil pipeline to Fairbanks, and along the general route of the Alaska Highway into Northern British Columbia or Alberta. Such a route has been suggested as an alternative for the Arctic Gas system by various parties, including the FPC environmental staff. Simply as a variant to the Arctic Gas proposal, adoption of the Alaska highway route would result in higher costs, because it would require an additional separate pipeline leg to serve the Mackenzie Delta gas reserves, its length depending upon whether it came

- (1) Southwesterly into the Yukon along the Dempster Highway,
- (2) South into Alberta as proposed by the Foothills group,
- or (3) Westward across the Arctic Slope to Prudhoe Bay.

Use of the Alaska highway routing would at first seem to have only two advantages over the system proposed by Arctic Gas: (1) a reduction of the likelihood of major cost overruns because the new system would follow existing transportation corridors, where construction conditions are less extreme and better known, and (2) less intense environmentalist opposition because the alternate route has far fewer river crossings and would not invade the Arctic Wildlife Range.

Coupled with two other changes relative to the Arctic Gas proposal, however, an Alaska highway system would appear to be considerably cheaper in initial capital outlay, and still competitive or even superior in terms of expected transportation tariffs for Prudhoe Bay gas. The first of these two variations is to use, as much as is practical, conventional technology and existing transportation facilities in the United States and Canada. The second is to postpone construction of a transportation system to serve the Mackenzie reserves.

Maximum Use of Existing Facilities

Arctic Gas originally proposed to build an entirely new trunkline system extending from Prudhoe Bay through the Mackenzie Delta into California on the West and Pennsylvania on the East. The Interior Department, among others, criticized this proposal for unnecessarily duplicating hundreds of miles of existing pipelines. As a result, the applicants have made some reductions in the scope of their proposal in the Lower 48, but there still appear to be significant opportunities for reducing first costs by using existing facilities, both in the United States and Canada.

The system with the lowest initial capital costs seems to be one which would tie into (1) the Westcoast Transmission system in Northern British Columbia and thence the Northwest Pipeline system for transportation of part of the gas to Western United States markets, and (2) the Alberta Gas Trunkline (AGTL) system and the Trans-Canada pipeline to the Great Lakes pipeline and other connections in the mid-western and eastern United States. These facilities would of course require some expansion and elimination of bottlenecks.

The Mackenzie Connection

The second departure from the general strategy of Arctic Gas concerns postponing a pipeline connection to the Mackenzie Delta and Canadian Beaufort Sea areas. If the reserves in this region were large enough to support half the total design capacity of the Arctic Gas pipeline, and if there were a Canadian or authorized export market for this much additional gas, the least expensive way of moving the Canadian gas would probably be to route the pipeline from Prudhoe Bay through the Mackenzie Delta and to provide sufficient capacity at the outset to carry the gas from both sources, in other words to adopt Arctic Gas' strategy.

But presently proved Mackenzie reserves fall far short of the Arctic Gas system's Canadian design capacity (2.24 billion cubic feet per day); the Interior Department estimates that proved and probable reserves in that area will support production of at most .9 to 1.1 billion cubic feet per day. At the same time, anticipated Canadian demand, plus existing contractual commitments to United States consumers, can be met for at least the next ten years from existing and anticipated reserves in the Western Provinces. On the other hand, even if there were enough Mackenzie gas to fill the pipeline, it would likely not be enough to induce the Canadian authorities to increase exports to the United States beyond those existing contractual commitments. All these propositions are conjectures, but the fact is that there is a good likelihood that a Mackenzie gas pipeline -- or at least a substantial part of its design capacity -- would be economically superfluous for many years after Prudhoe Bay gas began to flow. If this is the case, as seems probable, the Arctic Gas strategy is actually less economical than building a pipeline to carry exclusively Prudhoe Bay gas, by the least problematical route, and then to build a separate link later to connect the Mackenzie, when and if reserves and markets clearly indicate that it is justified.

At the beginning of this year these notions were only abstract possibilities because of the lack of any serious corporate interest in them. As one of the original participants in the Arctic Gas study groups, however, AGTL had advocated using existing pipeline facilities, including its own, to carry Alaska gas. The decision of Arctic gas to build a separate, competing trunk line was one of the reasons AGTL left the study group and (with Westcoast)

established the Foothills Pipeline Company to promote an all-Canadian "Maple Leaf" project for the Mackenzie Valley.

An inquiry in connection with the U.S. Senate hearings to Robert Blair, President of AGTL, about the probable costs of using existing Canadian transportation facilities was apparently one factor encouraging the Foothills group to appear at those hearings and at hearings of a committee of the Alaska legislature, where they set out their own rationale for a pipeline along the Alaska Highway route, which would maximize the use of existing Canadian pipeline facilities.

About the same time, some of the major environmental organizations began to explore the potentials of the Alaska Highway route, which they (along with the Federal Power Commission's environmental staff) regarded as far superior to either Arctic Gas' or El Paso's proposals, and a representative of one of the Midwestern governors started making similar inquiries. Similar but isolated interest began to appear on the part of business groups in Fairbanks and Yukon Territory, Provincial officials in Eastern Canada and gas utilities on both coasts. This alternative seemed to have a great deal of latent support. It lacked corporate sponsorship, however, and as late as March of this year it was not clear (1) that there was any way a third alternative could be seriously considered by the Federal Power Commission and Canada's National Energy Board, or (2) that Canadian authorities would consider approving any system principally designed to serve United States needs which did not result in an early connection of the Mackenzie reserves to Canadian Markets.

Procedural Feasibility of the Alaska Highway Alternative

Each of these doubts can be resolved, at least in part. The Foothills group (AGTL and Westcoast) is prepared to undertake construction and operation of the Canadian portion of the system. Northwest Pipeline, brought into the project by the Canadian companies, has announced its intention to apply to the Federal Power Commission by

July 9 for a certificate to build and operate the Alaska portion of the system, and is negotiating with other pipeline companies who might participate.*

It appears that both the Federal Power Commission and the National Energy Board can (and there are grounds for believing they must), consider a new application competitively. It is not clear whether addition of a third applicant in either case would necessarily mean a great delay in arriving at a decision. FPC Chairman Dunham estimates only a one to two month delay if Northwest files an application and all parties "cooperate."

Since a gas pipeline along the Alaska Highway route would traverse an established utility corridor and would not carry natural gas of Canadian origin, application to build such a pipeline apparently would not invoke Canada's elaborate Guidelines for Northern Pipelines, but could be treated as an expansion of Westcoast's existing system. The route has, moreover, already been thoroughly considered by the Berger Commission, which is investigating the implications of northern pipelines for the environment, Native welfare, and development of the Territories.

In the United States, procedural legislation will probably be approved which would much reduce the likelihood of administrative, regulatory or judicial delays arising from either two or three competing applications. Even if

*Perhaps it is not too heretical to suggest that Northwest's natural partners in this venture seem to be El Paso and Tenneco. Northwest's application significantly weakens both the rationale and the potential base for El Paso's own LNG proposal, yet the Northwest system is the logical route for delivering gas overland into El Paso's market area. Much of El Paso's engineering effort North of Fairbanks, moreover, could be transferred to the system proposed by Northwest.

Tennessee Gas Pipeline Company is not a sponsor of either the El Paso or the Arctic Gas application, but has been negotiating for Alaska's royalty gas on the basis of support for the El Paso proposal. Tennessee, however, now exports natural gas into the Trans-Canada system, and this connection may be a logical basis for serving its own market area with North Slope gas by displacement. Tenneco, moreover, is a participant in the Polar Pipeline project to deliver gas from the Canadian Arctic islands, a project which might benefit substantially from a delay in development of Mackenzie Delta reserves.

Northwest Pipeline had not decided to file an application, the legislation would be likely to require the Federal Power Commission and the President to consider all reasonable alternatives, which would clearly include the Alaska Highway route and maximum utilization of existing facilities.

What's in it for Canada?

The probable reception by Canadian authorities has been in my opinion the most difficult issue to judge. A major appeal of the Arctic Gas proposal is purportedly its early (if not necessarily more economical) attachment of the Mackenzie reserves. Without this feature, it may be asked, what is the advantage to Canada of accommodating the United States in moving Alaska gas?

The attachment of the Mackenzie reserves is, on the other hand, also a disadvantage of the Arctic Gas system, from one Canadian standpoint. There is no particular reason why Canada should not accommodate the United States with a transit line across Canadian territory; after all, a substantial portion of Canada's oil and gas supplies transits the United States. There would seem to be little objection in Canada on nationalistic grounds to American gas moving in either an American or a Canadian-owned pipeline across Canada. The Mackenzie project, however, raises the issue of an American-dominated consortium developing an important frontier area of Canada. The fact that an early Mackenzie connection is being justified in the United States by the (doubtful) proposition that it would lead to greater Canadian exports to the United States aggravates its potential difficulties in Canada. Both the timetable and logistics would be dictated by the convenience of the American interests. The Native claims and environmental complications of this route are also well known.

More importantly, however, a decision today in favor of immediate development of the Mackenzie Delta -- Beaufort Sea region can be seen to prejudice whether that region or the Arctic Islands (where recent exploration seems to have been more successful) shall be developed first.

Canada does not have an urgent internal need for gas production from either area, and development of either one could strain the capacity of domestic capital markets. Simultaneous

construction of the two pipelines under Canadian majority ownership is almost out of the question. It is not obvious which of these considerations is likely to be dominant in the eventual decision by the National Energy Board and the Cabinet, and it is possible to get contradictory opinions from key people in the decision process in Canada. The issue is clearly a blind-men-and-elephant situation; there is no person who can make an authoritative statement at this time.

On balance, however, my best informants in Canada indicate that there is a high-level commitment to a cooperative project with the United States concerning Alaska gas; absent a credible third application, this means that the Arctic Gas proposal will be approved. The Maple Leaf project is not a serious contender at this time.

A decision in favor of Arctic Gas would, however, be a reluctant one and would be opposed from many quarters within the Canadian federal government, by several provinces and by a large body of Canadian opinion. These objections rest on a broad range of environmental, economic, nationalistic and Native claims considerations, and most decisively perhaps on the fact that approval of Arctic Gas would effectively preclude or postpone for many years the Polar alternative. For these reasons, my own tentative judgment is that the Canadian government will -- once it has had an opportunity to consider the alternative -- welcome the opportunity to avoid an early decision one way or another regarding the Mackenzie.

The State of Alaska and the El Paso Proposal

Some of the concerns that led the Alaska state government and the bulk of the state's business and political communities to support the El Paso proposal were set out in detail in my 1975 report to the State Task Force, which provided part of the rationale for the Governor's endorsement of El Paso's application before the Federal Power Commission. The main theme of that report was that the cost of moving North Slope gas to the Lower 48 by either proposed system would be so great that the wellhead value of the gas would be very low -- if it was indeed high enough to justify investment in developing the field. As a result, the State's royalty and severance tax revenues from sale

of the gas in interstate commerce would be negligible compared with the contributions a Trans-Alaska pipeline might make to the State's economy through, for example, (1) the payrolls, profits and tax collections from pipeline and terminal construction, (2) property and income taxes on the pipeline and terminal when it was operating (3) the availability of natural gas in the Fairbanks area for household and commercial use and at tidewater in Southcentral Alaska, where it might be used as an industrial fuel or feedstock.

The system proposed by Arctic Gas would probably have meant lower average transportation costs to the Lower 48, and therefore, a higher "netback" value at the wellhead. But the effect of this difference on state revenues and economic activity would have been negligible compared to the economic disadvantage of removing the gas from Alaska at its most remote corner, with a minimum of construction activity and resulting capital plant within the state, and the virtual inability of the populated areas of the state to obtain any Prudhoe Bay gas for domestic or industrial use.

The El Paso proposal was remarkable in that -- at least temporarily -- it won the support of both the pro-development interests in Alaska and the environmentalists. For at least two years it has seemed that there was almost complete unanimity in Alaska in support of El Paso's application.

Despite my own role in helping to create this consensus (through the rationale for a Trans-Alaska pipeline, developed in my report to the Task Force), I have not been able to endorse the uncritical and increasingly irrational commitment of State spokesmen to the El Paso application. Firstly, the State has almost certainly been betting on a dead horse. The technical, economic and logistical inferiority of the LNG system from a national standpoint is so overwhelming that Alaska's views or political influence are not likely to carry much weight in the ultimate outcome. Not only is there unanimity in the Midwest and East in favor of a system that would deliver the gas directly into those regions of the United States which face the greatest shortages, but California, the state that would directly receive the LNG, prefers an overland pipeline alternative for economic reasons which seem to me wholly persuasive (and increasingly, it appears, for safety and environmental reasons also).

In view of the growing consternation about the West Coast crude oil "surplus," resulting from the choice of a Trans-Alaska route for the oil pipeline, it seems quite improbable that Congress would compound the imbalance by agreeing to a Trans-Alaska pipeline and LNG tanker system for North Slope natural gas so long as an all-pipeline route is a serious possibility. The imbalance in domestic energy sufficiency between the West Coast and the rest of the United States would of course be further aggravated by any major new oil or gas discoveries in Lower Cook Inlet or the Gulf of Alaska.

To offset the weakness of their economic and logistical arguments from a national standpoint, and their almost non-existent national political base, the supporters of El Paso in Alaska built their case largely on exaggerated and often unreasonable claims about Canadian interests, institutions and intentions. In some cases it seemed as if this rhetoric was deliberately designed to worsen relations between the United States and Canada. These claims were advanced, ironically, in support of a company which now imports LNG from Algeria and is presently promoting a project to bring LNG from the Soviet Union.

The case, even from an Alaskan standpoint, for the Trans Alaskan gas pipeline was systematically and increasingly exaggerated, not only by the Anchorage Times and OMAR but by state government spokesmen. Little consideration was given to the possibility that the natural gas available from new discoveries in Southcentral Alaska would exceed any anticipated domestic and industrial demand there, and that El Paso's terminal at Gravina Point was in any case hundreds of miles from the principal gas markets of the state and the logical sites for industrial development in the Cook Inlet-railbelt area. Little attention was given to the fact that the State could make its North Slope royalty gas effectively available in South Central Alaska, by exchange for Cook Inlet gas, even if the Arctic Gas system were built.

Little weight, evidently, was given in the State's strategy to the negative environmental impacts of the additional population growth and the prolonged overheating of Alaska's economy which would result from a second pipeline boom. It was particularly ironic -- and to me disappointing -- that a state Administration which came to office because of public reaction against the excesses of

the oil pipeline boom, and the boomer psychology, should so completely adopt on this issue the outlook of people who vehemently opposed Governor Hammond's election, and who would not support him whatever he did.

By its unconditional support of El Paso, the state gave that company no incentive to accommodate Alaska's interest by, for example, choosing a terminal in Cook Inlet rather than Prince William Sound, or by maximum use of the oil pipeline pad in order to minimize environmental disturbance from the second line. At the same time the State effectively told Arctic Gas -- which was much more likely to prevail ultimately -- that there was no accommodation it could make to the State's interest (like choice of an Alaska Highway route) that would soften the State's position of support for El Paso.

Alaska and the Northwest Pipeline Proposal

Northwest Pipeline, together with Westcoast Transmission and AGTL have this month formally proposed to build a system from Prudhoe Bay along the oil pipeline route to Fairbanks, then following the Alaska Highway to Fort Nelson, British Columbia and Zama Lake, Alberta where the gas would enter existing transmission facilities. These facilities would be expanded where necessary to accommodate the increased volumes. [A description by Northwest is appended to this letter.]

The pipeline concept proposed by Northwest would have several technical and financial advantages over the other two systems. By using a 42 inch pipeline, conventional technology, and a corridor where there has already been highway and/or pipeline construction, for the route segments which require entirely new construction, and by maximum employment of existing facilities, the initial capital cost outlay before any gas or cash could begin to flow might be held to little more than half that anticipated for the Arctic Gas system. The likelihood of large cost overruns, as well, would be much reduced by these features. The system could begin to operate with a flow of as little as a billion cubic feet per day (though I don't see how even this project would be economically viable unless its throughput ultimately reached at least 2 billion). And, in my judgment, the political and regulatory barriers to an Alaska Highway system would be far less formidable than for either of the other two systems.

There is good reason to believe that the announcement by Northwest makes the Alaskan commitment to El Paso obsolete, and that support within the State for that company's proposal may deteriorate rapidly. The Northwest project would avoid most of the environmental objections to the Arctic Gas system; it also makes gas available in the Fairbanks area and involves almost as much pipeline construction within Alaska as would the El Paso system. Because it does not involve an LNG terminal, however, the peak impact of the boom resulting from building an Alaska Highway system would be substantially smaller. This outcome can be seen as either better or worse for Alaska.

According to preliminary estimates from the University of Alaska's Man in the Arctic program, construction of the Arctic Gas system would add \$19 million to the State's gross product and three thousand persons to the State's population in the peak year of construction. The El Paso system would increase gross product by \$235 million and population by 24 thousand while the Alaska Highway system would increase Alaska gross product by \$111 million and population by 15 thousand. These calculations do not take account of the fact that Haines and Skagway would undoubtedly be major ports of entry for materials and equipment destined for construction activities in Yukon Territory.

For these reasons, the Northwest proposal seems at the very worst to be a workable compromise that would be acceptable to almost every important Alaskan interest group. The newly proposed system may, however, be more attractive to Alaskans than as just a fallback position or a workable compromise. Northwest Pipeline's approach to the State contrasts sharply with the "take it or leave it" stance of both of the original applicants. Northwest has at least informally suggested that the State take an equity share in the pipeline system and take part in the planning and in its operation from the inside. The company also has approached or plans to approach Alaska-based corporations including the Arctic Slope Regional Corporation and Doyon, Ltd. for participation, and has suggested that a block of shares in the enterprise be offered to the general public in Alaska. The effect of these innovations would be to assure that the system within Alaska would be closely identified with local interests and be responsive to them.

Another initiative proposed by Northwest (to the Royalty Board) includes acquisition of gas reserves in the Cook Inlet area, which could be provided to the State for intrastate use in exchange for state royalty gas exported by Northwest to the Lower 48. Northwest spokesmen have also talked about advance planning for a possible "Phase II" pipeline spur from Fairbanks to the Cook Inlet area. This addition would be built to serve domestic and industrial customers there when and if existing newly discovered reserves in Southcentral Alaska proved inadequate to the area's requirements. None of these concepts is yet a firm commitment, much less a reality, but if the sponsors of the new system actually proceed along these lines they will quickly rally very significant support in the State.

Regional Interests Outside of Alaska

The Alaska Highway pipeline proposal offers significant advantages over the two other proposed systems to a wide variety of regional and sectoral interests outside of Alaska.

(1) For British Columbia, introduction of Prudhoe Bay gas will more fully utilize the existing facilities of Westcoast Transmission, and thereby reduce the cost of British Columbia gas delivered to consumers in the Province. Construction of a pipeline through the Yukon would provide a stimulus to the development of that Territory, and strengthen its links with market and financial centers in British Columbia. The proposal is now being discussed in the Province as a possible justification for extending the British Columbia Railway to Whitehorse and eventually to Fairbanks. For these reasons, the Provincial Government is considering joining in the pipeline project, perhaps as an equity participant.

(2) The system proposed by Northwest Pipeline is by far the most economical method of moving North Slope gas into the Pacific Northwest, and it is for that reason supported by all the gas distributors of the region. In contrast to the Arctic Gas proposal (which is a second-best gas supply alternative for the Northwestern states), construction of an Alaska Highway system would rely mainly on Seattle-Tacoma and other ports in the region as supply and transportation bases. The Alaska Highway route would

probably not make as large a contribution to Port of Seattle activity and revenues as would El Paso's LNG project. The latter is not in my judgment likely to prevail, however, and the Alaska Highway system offers maritime interests in the Northwest the greatest volume of business they are actually likely to obtain from any Alaska gas transportation system.

(3) For California the Alaska Highway system offers a comparatively economic and (because it utilizes conventional technology) reliable source of incremental gas supply. Unlike the El Paso project it would not raise novel safety issues nor would it displace California's present low price gas from the Permian Basin in favor of high price LNG imports from Alaska.

(4) For the United States Midwest and East the Alaska Highway project (like the Arctic Gas project) would provide an assured supply of natural gas directly into the market areas where the shortages are most acute. Because of its smaller risk of construction delays and cost overruns, however, the Alaska Highway system should on balance be preferable. By preserving Canada's option to develop the Arctic Islands and the Polar Pipeline earlier than the Mackenzie Delta and Beaufort Sea, the Alaska Highway proposal may offer a better possibility of increasing producible and transportable Canadian reserves to such a quantity that the Canadian Government would be willing to consider new export commitments.

(5) The project would be supported by the crucially important Province of Alberta (which now opposes the Arctic Gas application) because it would contribute to the optimum use of Alberta's own gas transmission system, rather than establishing a competing trunkline through the Province. Unlike Arctic Gas, moreover, the new system would not in the immediate future compete with, and require the shutting in of, Alberta gas now dedicated to markets in Eastern Canada.

(6) For Canada as a whole the Alaska Highway proposal would postpone the necessity of deciding when, how and by whom the Mackenzie Delta-Beaufort Sea region was to be developed, and whether that region or the Arctic Islands should take first priority for development among Canadian frontier regions. By reducing the total amount of new

construction and shifting a substantial part of the construction out of Canada and into Alaska, the Alaska Highway system would reduce the stress on Canadian capital and labor markets and on the nation's foreign exchange position.

There cannot help but be some losers. First, of course, are those gas transmission companies whose projects would be turned down and the construction and service firms who hoped to build a bigger system or a different system from the one which is finally approved. There are Exxon, whose affiliate Imperial Oil is part of the Arctic Gas group, and other producers with interests in the Mackenzie, who would be deprived of an early hookup to their Arctic reserves, however superfluous that hookup may be at the present time from the standpoint of Canada's energy economy. Finally there are those who would expect to build and operate the LNG tankers if the El Paso project prevailed, together with those (in the Port of Seattle, for example) who hope for a larger demand for their transportation and other services than an Alaska highway project can generate.

On balance, however, if we take into account the lower front-end cost, the smaller vulnerability to cost overruns and the widely agreed-upon environmental advantages of the Alaska Highway Route, the system proposed by Northwest seems to be the best practical alternative for almost every region in both Canada and the United States. Together with its broad acceptability to Alaskan's these considerations make the Northwest proposal a possible winner. On its merits it now seems to be distinctly superior to both of the other proposals from a national viewpoint, and at least as good as El Paso's proposal from an Alaskan perspective.

For this reason it was a relief that the Administration was not able to complete arrangement during this session of the legislature to sell Alaska's North Slope royalty gas to pipeline companies who promise in return to give

political support for the El Paso project. It is fortunate that the Royalty Board did not have to vote on any such sale and that the legislature did not have to face the issue in its last days. The choices for Alaska have changed radically -- and so have their political implications. I believe that the State's position will have to move soon to reflect these changes.

Very truly yours,

Arlon R. Tussing

cc: Governor Jay Hammond
Speaker Mike Bradner



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AN INKILING OF THE LONG JOURNEY

Arlon R. Tussing

There are, I believe, serious questions about the viability of the transportation systems proposed by both the Arctic Gas consortium and the El Paso Company for taking Alaska natural gas to U.S. markets. An investigation I conducted in 1975 on the economics of the two proposals for the State of Alaska raised the possibility that the cost of delivering the gas might actually exceed its value to consumers. At best, it appears that both projects, as proposed by their sponsors, are so risky that it may not be possible to finance them privately, even if their political and regulatory problems can be overcome — itself a questionable issue.

Both U.S. projects face the following risks:

Gas supplies: Production from the Alaska North Slope, and in the case of the Arctic Gas proposal, from the Mackenzie Delta, may be substantially less than the design capacity of either transportation system, meaning that each unit actually carried would have to bear a larger portion of the system's fixed costs than projected by its sponsors.

Delays and capital cost overruns: Actual construction costs may exceed estimated costs by substantially more than the effect of general inflation. The Arctic Gas project involves construction and operating technology untested in North America, while its route traverses hundreds of miles of difficult Arctic terrain where there has been no previous construction of either pipelines or roads. El Paso proposes a system of unprecedented pipeline pressures and a huge scale-up of existing liquified natural gas (LNG) technology. New technology, unfamiliar environments, and a large scale — relative to previous projects, are exactly the ingredients of the most spectacular cost overruns. Arctic Gas, for example, envisions a system from Alaska, across Canada, and into the Lower

48 States with an estimated cost in 1975 dollars of about 8½ billion. I would not be surprised to see the total cost of either project exceed \$20 billion, including interest on funds used during construction.

Experience in North America with big, custom-engineered construction projects has been that they normally cost two or three times their original projections, even including an allowance for inflation. Cost estimators are like accountants in that they prefer a solid,

empirically based figure to a realistic figure. They do attempt to project the increase in anticipated labour rates and in the prices of specific materials but they don't take into account the fact that huge projects, particularly if they involve new technology or a remote construction site, usually don't work the first time around, nor that both the purchaser and the licensing authorities change their minds several times in the course of planning and construction. The cost engineers don't appreciate that



"It's new, man—it's bound to have a few little bugs."

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such projects are usually clumsily managed and subject to a number of re-organizations during their design and construction. They don't allow for the fact that materials and equipment are always late and often mis-specified or defective, or that enterprises of this sort suffer not normal, but abnormal labour cost increases. Because of their size and urgency, they are especially vulnerable to wage pressure, even more so to featherbedding, and often to racketeering.

The Alaska oil pipeline was initially estimated at something less than one billion dollars in 1969. It will finally come in at a cost between eight and ten billion. This particular project is an especially horrible example because it has suffered from each of the diseases I mentioned. But it isn't unique. Nuclear generating plants in the United States have been coming in at four to five times their projected cost per on-line kilowatt.

On this basis the cost of the Arctic Gas project could easily become twenty billion dollars. Let's assume it will cost twenty billion and also that the project is to be paid for in 20 years, that is, a five percent amortization. Let's also assume that the investors should receive a 15 percent pre-tax rate of return on total assets.* Under a conventional utility accounting scheme, the project would need a first year cash flow of four billion dollars just to cover its fixed costs. On a discounted cash flow basis the annual fixed charge would be about \$3.2 billion.

With a throughput of something like a trillion cubic feet per year, we are talking of \$3.20 to \$4.00 per thousand cubic feet (mcf) for the capital plant just to get the gas into the existing distribution systems in the Lower 48 states and eastern Canada. If less gas can be delivered, as is likely, the cost would be even higher. This charge doesn't include the cost of developing the gas fields, any return to the producers, royalties, operating costs or costs of distribution.

Market: Both El Paso and Arctic Gas insist that the natural gas shortage in the United States is an absolute one, and that Lower 48 markets will accept North Slope natural gas at any price. Not everyone agrees; the Federal Energy Administration, for example, estimates that no market for Prudhoe Bay gas would exist in 1985 at a "city gate" price exceeding \$2.40 per million BTU (in 1975 dollars). The Interior Department's study reaches a similar conclusion. This price could easily be exceeded even without implausibly large

Experience in North America with big, custom-engineered construction projects has been that they normally cost two or three times their original projections, even including an allowance for inflation. New technology, unfamiliar environments, and a large scale — relative to previous projects, are the ingredients of the most spectacular cost overruns.

cost overruns or shortfalls in gas supplies to the system.

One assumption of the studies mentioned here is that natural gas field prices are free of Federal Power Commission (FPC) controls, and that the Alaskan gas is priced incrementally. Even relaxing these assumptions, however, it is not at all clear how much customers would be willing to pay on a year-round basis for the quantity of gas that would be carried by this system. The gas delivered through such a pipeline would be a base load supply delivered into southern distribution systems which have typical load factors in their premium markets of less than 40 percent. The seasonal swing in residential and commercial demand is one reason why about half the natural gas produced in the United States is now being burned as a boiler fuel. Some of the gas from the Arctic would have to be "dumped" in the boiler fuel market in competition with heavy fuel oil at an equivalent of about \$2.00 or coal at about \$1.00. The cost of Arctic gas delivered into the distribution system for premium customers could therefore reach \$5.00, \$6.00 or even more, per million BTU. Six dollar gas is about equivalent to oil at \$30.00 per barrel. It would seem on its surface that there ought to be some question about the economic wisdom of such a project.

Political, regulatory and other institutional issues: Each project would face serious political and legal obstacles, even after it received a certificate from the Federal Power Commission. Lack of co-ordination in U.S. and Canadian approvals, for example, could block or delay construction of the Arctic Gas system, while there is some chance that resistance in California to port and terminal facilities would jeopardize completion of the El Paso system. The Arctic Gas system is, significantly, opposed by the governments and the preponderance of public opinion in both Alaska and Alberta, and the El Paso system is widely opposed within the state

of California, where the liquified natural gas would be landed. The major environmental organizations are hostile to both projects. Neither they nor various local interest groups are likely to abandon every attempt to obstruct or delay construction simply because the system has been sanctioned by the Federal Power Commission.

Financing problems: The financial consequences of the risks I have listed are magnified by the fact that neither project can be built in smaller self-sustaining stages. Either would be a large integrated system which could not carry any gas or produce any cash flow until it was completed. Most of the capital invested (\$10 to \$20 billion or more) would therefore be exposed to these factors for at least the entire planning and construction period.

Private leaders simply will not accept risks of this sort, and neither project sponsors are financially large enough to carry them, even if they were willing to do so. They do not in fact seem to be willing, as they both propose tariff conditions which would protect their profits as well as their debt service obligations against "all events". Only federal governments and/or, perhaps, potential gas consumers are in a position to carry financial risks of the associated with either of the systems.

Accordingly, El Paso proposes to federal loan guarantees (under an existing programme) for its LNG tankers and spokesmen for Arctic Gas have suggested that governments indemnify the sponsors against cost overruns exceeding 40 percent (nearly certainly my judgement). But, more importantly, each applicant proposes to rely on cost of service all-events tariffs to cover their debt service obligations and to ensure a return on their equity. These tariffs provide, in brief, that consumers are required to pay the debt service operating costs of the transport system (plus a profit to the owners) no matter how great these costs are, whether or not the customers receive any gas. Arctic Gas's tariff would begin to run as soon as gas was first delivered; El Paso's would begin 60 months after approval of its project, even if it were never completed.

The proposition that consumers should bear or share in the risks associated with a project which bears them is not in itself unreasonable, provided that the economic expectations of the project are clearly favourable and the risks are of a reasonable magnitude. But with these projects there are reasons for doubt on both scores. Moreover, even if the Federal Power Commission were to approve "all-events" tariffs, local gas distributors would

* For example, on 75 percent debt at an average interest rate of 10 percent, a 15 percent after-tax return on equity and a 50 percent average tax rate on profits.

sign contracts containing such tariffs unless they were assured in advance by their state regulatory commissions (as well as by their own market analyses) that they would be able to pass these charges through to their own customers. Responses by the state commissions to Federal Power Commission enquiries suggest that there is almost no chance that they would give such advance approval.

These considerations lead inexorably to the conclusion that neither system can be built in the form proposed by their sponsors without either substantial federal financial backing, Federal Power Commission authority to preempt the jurisdiction of state utility commissions over the tariffs of local distributors, or both. No plausible proposals of either sort have yet been made, either by the applicants or by any of the responsible federal agencies.

Perhaps the most chilling prospect is that the Federal Power Commission (and the National Energy Board, in the case of the Arctic Gas project) would license one of the projects on the basis of conventionally estimated costs. The Commission would permit the transmission companies to begin collecting interest on construction debt before the project goes on line, and on that assurance the capital market would provide the sponsors with three or four billion dollars for engineering studies, site preparation and materials acquisition.

At the completion of this first phase, the sponsors will try to borrow the money for actual construction. At this time the cost estimators will have brought the figure up to \$13 or \$14 billion or more. After some point even all-events tariffs would not assure debt repayment, so that the money just won't be there to finish the system.

But a commitment would have been made. The transmission companies and their customers will come to Congress (and the Canadian government) with figures that show the present benefits will still exceed the present costs, because sunk costs don't matter (except to the investors). They'll talk about the pressing need of consumers who don't have any alternative in sight (because they have been counting on Arctic gas), they'll talk about energy self-sufficiency, and they'll talk employment and the balance of payments. If Congress and the Canadian Parliament have any inkling now about the long journey on which they are about to embark, they may hesitate.

In summary, there seem to be two problems that work together to make questionable the completion of either project as proposed; each of them requires too large an initial capital, and

that capital would be exposed to too many large risks. Once these are recognized as the critical problems to be overcome, it is obviously worthwhile to investigate whether there might not be some alternative system (or modification of one of the applicant's systems) which could begin with a smaller investment and perhaps be expanded in stages after gas and income begin to flow, a system with a smaller potential for cost overruns, and one which would raise less opposition on environmental, development or economic nationalist grounds.

The proposition that consumers should bear or share in the risks associated with a project which benefits them is not in itself unreasonable, provided that the economic expectations of the project are clearly favourable and the risks are of a reasonable magnitude. But with these projects there are good reasons for doubt on both scores.

The Fairbanks-Alcan route: One system which seems to have the possibility of meeting some of the criteria mentioned here would be an overland natural gas pipeline along the general route of the Trans-Alaska oil pipeline to a point about 100 miles south of Fairbanks, and along the general route of the Alaska Highway into northern British Columbia or Alberta. Such a route has been suggested as an alternative for the Arctic Gas system by various parties, including the FPC environmental staff. Simply as an optional way of completing the Arctic Gas proposal, however, the Alaska Highway route would result in higher costs, because an additional separate pipeline leg would be required to bring the Mackenzie Delta gas reserves to market.

Use of the Alaska Highway routing would at first seem to have only two advantages over the system proposed by Arctic Gas: a reduction of the likelihood of major cost overruns because the new system would follow existing transportation corridors, where construction conditions are less extreme and better

known, and less intense environmental opposition because this route has far fewer river crossings, would not invade the Arctic Wildlife Range, and follows a corridor already affected by development.

Coupled with two other changes relative to the Arctic Gas proposal, however, an Alaska Highway system would appear to be considerably cheaper in initial capital outlay, and still competitive or even superior in terms of expected transportation tariffs for Prudhoe Bay gas. The first of these two variations is to use, as much as is practical, conventional technology and existing transportation facilities in the United States and Canada. The second is to postpone construction of a transportation system to serve the Mackenzie reserves.

Northwest Pipeline Company, a U.S. company, together with three Canadian companies, Westcoast Transmission, Alberta Gas Trunk (AGTL), and Foothills Pipeline Co. (a joint venture of the other two) has formally proposed to build a system from Prudhoe Bay along the oil pipeline route to Fairbanks, then following the Alaska Highway to Fort Nelson, British Columbia and Zama Lake, Alberta, where the gas would enter existing Canadian transmission facilities. These facilities would be expanded where necessary to accommodate the increased volumes.

The pipeline concept proposed by Northwest and its Canadian partners would have several technical and financial advantages over the other two systems. It uses a 42-inch pipe, conventional technology, a corridor where there has already been highway and/or pipeline construction, and maximum employment of existing facilities. By virtue of these changes, the initial capital cost outlay before any gas or cash could begin to flow might be held considerably lower than the cost officially anticipated for the Arctic Gas system. The likelihood of large cost overruns, as well, would be much reduced by these features. Whereas ultimately, higher volumes would be required to cover the investment, the system could begin to operate with a flow of as little as a billion cubic feet per day. And, in my judgement, the political and regulatory barriers to an Alaska Highway system would be far less formidable than for either of the other two systems.

The system proposed by Northwest, Foothills, et al, may not yet be the cheapest way of moving Alaska gas to the United States Midwest and East. The Alcan proposal presented to the FPC and NEB still includes the 1117 mile Northern Border pipeline, which is part of the Arctic Gas system. The sys-

"In September 1976 the FPC staff issued an Alcan system supplement to the Final Environmental Impact Statement on Alaska natural gas transportation systems. The supplement urges "that none of the proposals be approved as proposed." It concludes that the Arctic gas proposal would be environmentally superior to other alternatives if the leg to the Western United States were dropped and that area were served with Alaska gas by displacement and the "Fairbanks Corridor" (Alcan Highway) route were adopted. The FPC staff did not endorse the Alcan proposal of Northwest and Foothills "because it lacks the necessary expansion flexibility."

tem with the lowest initial capital cost, however, seems to be one which would expand the Trans-Canada pipeline and the Great Lakes pipeline, instead of building an entirely new line across the Prairies. Both the U.S. and Canadian partners in the Alcan project understand the advantages of maximizing the use of existing facilities, and I can only speculate on the reason for retaining Northern Border. The Trans-Canada Pipeline Company, which is part of the Canadian Arctic Gas group, may be unwilling to co-operate with a rival proposal at this time, although there is no reason to suppose that Trans-Canada's facilities would not be available to move Alaska gas if the Arctic Gas proposal were to be rejected by the National Energy Board.

There is good reason to believe that the announcement by Northwest makes the State of Alaska's commitment to support El Paso obsolete, and that this support may deteriorate rapidly. The Northwest project would avoid most of the state's environmental objections to the Arctic Gas system; it also makes gas available in the Fairbanks area and involves almost as much pipeline construction within the state as would the El Paso system. Because it does not involve an LNG terminal, however, the boom resulting from building a pipeline along the Alaska Highway would be substantially smaller than the boom that would be generated by the El Paso project.

Alaska and the Alcan proposal: According to preliminary estimates from the University of Alaska's Man in the Arctic Program, construction of the Arctic Gas system would add \$19 million to the state's gross product and three thousand persons to the state's population in the peak year of construction. The El Paso system would increase gross product by \$235 million and population by 24 thousand, while the Alaska Highway pipeline routing would increase Alaska's gross product by \$111 million and population by 15 thousand. These calculations do not take account of the fact that Haines and Skagway would undoubtedly be major ports of entry for materials and equipment destined for construction activities in Yukon Territory.

For these reasons, the Northwest proposal seems at the very worst to be a workable compromise that would be acceptable to almost every important Alaskan interest group. The newly proposed system may, however, be more attractive to Alaskans than as just a fallback position or a workable compromise. Northwest Pipeline's approach to the state contrasts sharply with the "take it or leave it" stance of both of the original

applicants. Northwest has at least informally suggested that the state take an equity share in the pipeline system and take part in its planning and operation. The company also has approached, or plans to approach, Alaska-based corporations for participation, including the Inuit-owned Arctic Slope Regional Corporation and the Athabaskan-owned Doyon, Ltd., and has suggested that a block of shares in the enterprise be offered to the general public in Alaska. The effect of these innovations would be to ensure that the system within Alaska would be closely identified with local interests and be responsive to them.

Regional interests outside of Alaska: The Alaska Highway pipeline proposal offers significant advantages over the two other proposed systems to a wide variety of regional and sectoral interests outside of Alaska.

British Columbia

For British Columbia, introduction of Prudhoe Bay gas will more fully utilize the existing facilities of Westcoast Transmission, and thereby reduce the cost of British Columbia gas delivered to consumers in the province. Construction of the pipeline would provide a stimulus to the development of northern British Columbia and Yukon Territory, and strengthen the territory's links with market and financial centres in British Columbia. The proposal is now being discussed in the province as a possible justification for extending the British Columbia Railway to Whitehorse and eventually to Fairbanks. For these reasons, the provincial government has endorsed, and is reportedly considering joining in the pipeline project, perhaps as an equity participant.

Alberta

The project could be supported by the crucially important Province of Alberta (which now opposes the Arctic Gas application) because it would contribute to the optimum use of Alberta's own gas transmission system, rather than establishing a competing trunkline through the province. Unlike Arctic Gas, moreover, the new system would not in the immediate future compete with, and require the shutting in of, Alberta gas now dedicated to markets in eastern Canada.

Canada

For Canada as a whole, the Alaska Highway proposal would postpone the necessity of deciding when, how and by whom the Mackenzie Delta — Beaufort Sea region was to be developed, and whether that region or the Arctic Islands should take first priority for develop-

ment among Canadian frontier regions. By reducing the total amount of new construction and shifting a substantial part of the construction out of Canada and into Alaska, the Alaska Highway system would reduce the stress on Canadian capital and labour markets and on the nation's foreign exchange position.

Pacific Northwest

The system proposed by Northwest Pipeline is by far the most economical method of moving North Slope gas into the Pacific Northwest, and it is for that reason supported by the gas distributors of the region. In contrast to the Arctic Gas proposal (which is a second-best gas supply alternative for the Northwestern states), construction of an Alaska Highway system would rely mainly on Seattle-Tacoma and other ports in the region as supply and transportation bases for the northern half. The Alaska Highway route would not make as large a contribution to Port of Seattle activity and revenues as would El Paso's LNG project but the latter is not in my judgement likely to prevail, and the Alaska Highway system therefore offers maritime interests and construction in the Northwest the greatest volume of business they are actually likely to obtain from any Alaska gas transportation system.

California

For California, the Alaska Highway system offers a comparatively economic and (because it utilizes conventional technology) reliable source of incremental gas supply. Unlike the El Paso project it would not raise novel safety issues nor would it threaten to displace California's present low price gas from the Permian Basin in favour of high price LNG imports from Alaska.

Midwest & East

For the United States' Midwest and East, the Alaska Highway project (like the Arctic Gas project) would provide an assured supply of natural gas directly into the market areas where the shortages are most acute. Because of its smaller risk of construction delays and cost overruns, however, the Alaska Highway system should, on balance, be preferable. By preserving Canada's option to develop the Arctic Islands and the Polar Gas pipeline earlier than the Mackenzie Delta and Beaufort Sea, the Alaska Highway proposal may offer a better possibility (however remote) of increasing producible and transportable Canadian reserves to such a quantity that the Canadian government would be willing to consider new export commitments.

There cannot help but be some losers. First, of course, are those gas transmission companies whose projects would be turned down and the construction and service firms who hoped to build a bigger system or a different system from the one which is finally approved. There is Exxon, whose affiliate Imperial Oil is part of the Canadian Arctic Gas group, and other producers with interests in the Mackenzie, who would be deprived of an early hookup to their Arctic reserves, however superfluous that hookup may be at the present time from the standpoint of Canada's energy economy. Finally, there are those who would expect to build and operate the LNG tankers if the El Paso project prevailed, together with those (in the Port of Seattle, for example) who hope for a larger demand for their transportation and other services than an Alaska Highway project can generate.

For Canada as a whole, the Alaska Highway proposal would postpone the necessity of deciding when, how and by whom the Mackenzie Delta-Beaufort Sea region was to be developed, and whether that region or the Arctic Islands should take first priority for development among Canadian frontier regions.

On balance, however, if we take into account the lower front-end cost, the smaller vulnerability to cost overruns, and the widely agreed-upon environmental advantages of the Alaska Highway route, a system similar to that proposed for the Alcan may be the best practical alternative for almost every region in both Canada and the United States. Together with its broad acceptability to Alaskans these considerations make a system like that proposed by Northwest and Foothills a possible winner despite its late entry into the competition.

Arlon R. Tussing

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What's in it for Canada?

The probable reception of any Alcan proposal by Canadian authorities has been a most difficult issue to forecast. A major appeal of the Arctic Gas project is purportedly its early (if not necessarily more economical) attachment to the Mackenzie reserves. Without this feature, it may be asked, what is the advantage to Canada of accommodating the United States in moving Alaska gas?

The attachment of the Mackenzie reserves may, on the other hand, be seen as a major *disadvantage* of the Arctic Gas system, from at least one Canadian standpoint. There is no particular reason why Canada should *not* accommodate the United States with a transit line across Canadian territory; after all, a substantial portion of Canada's oil and gas supplies transits the United States. There would seem to be little objection in Canada on nationalistic grounds to American gas moving in either an American or a Canadian-owned pipeline across Canada. The Mackenzie project, in contrast, raises the issue of an American-dominated consortium developing an important frontier area of Canada. The fact that an early Mackenzie connection is being justified in the United States by the (doubtful) proposition that it would lead to greater Canadian exports to the United States aggravates its potential difficulties in Canada. Both its timetable and logistics would be dictated by the convenience of the American interests. The native claims and environmental complications of this route are also well known.

If Congress and the Canadian Parliament have any inkling now about the long journey on which they are about to embark, they may hesitate.

The 60 trillion cubic feet of proved reserves in the western provinces are enough to sustain the expected growth of Canadian demand plus present export contracts for about ten years. This would be the case even if there were no further discoveries, but recent exploratory results in Alberta have been rather encouraging, more so in fact than in the delta area. For this reason a decision on an Arctic pipeline carries much less urgency for Canada than it does for the United States.

More importantly, however, a decision today in favour of immediate development of the Mackenzie Delta-Beaufort Sea region can be seen to prejudice whether that region or the Arctic Islands (where recent exploration seems to have been more successful) shall be developed first. Either project could strain the capacity of domestic capital markets so that simultaneous construction of two major pipeline systems under Canadian majority ownership is almost out of the question.

It is not obvious which of several competing considerations is likely to be dominant in the eventual decision by the National Energy Board and the Cabinet, but on balance there now appears to be a favourable climate for a co-operative project with the United States concerning Alaskan gas. If the Alcan project were not a serious contender, this means that the Arctic Gas proposal would be approved. The Maple Leaf project is not timely either in terms of known reserves or in terms of Canadian demand, and it is not a serious contender at this time.

A decision in favour of Arctic Gas would, however, be a reluctant one and would be opposed from many quarters within the Canadian federal government, by several provinces and by a large body of Canadian opinion. These objections rest on a broad range of environmental, economic, nationalistic and native claims considerations, and most decisively perhaps on the fact that the approval of Arctic Gas might effectively preclude or postpone for many years the Polar Gas alternative. For these reasons, my own tentative judgement is that the Canadian government will — once it has had an opportunity to consider the alternative — welcome the opportunity to avoid an early decision one way or another regarding the Mackenzie. This is likely the biggest benefit to Canada from the Alcan proposal.

Arlon R. Tussing

NATURAL GAS SUPPLY
OUTLOOK FOR
THE WEST

SUMMARY OF COMMENTS

BY

ARLON R. TUSSING

AT

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.

WORKSHOP ON ECONOMIC GROWTH IN THE WEST

AND RELATED ENERGY PROBLEMS

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1. It no longer means much to speak of a gas supply outlook for the Pacific states as distinct from the outlook for the contiguous 48 states as a whole. With a nearly complete nationwide gas transmission network and transmission loads that are stagnant or declining, an abundance or shortage of gas in one region can be shifted to any other region or spread evenly across the country, without major investments in new transportation capacity.

2. The emergence of a single national market for natural gas is of course inhibited by FPC wellhead price controls, which discourage both interstate sales generally and reallocation of gas among interstate purchasers. And existing long term sales contracts together with the need for certification and abandonment proceedings before the FPC and state commissions make even the most economically logical exchange and displacement arrangements difficult to put into effect.

3. Nevertheless, if institutional obstacles effectively prevent the smoothing out of gross regional disparities in gas supply, we can expect Congress to give the FPC authority to reach into intrastate markets, to allocate new natural and synthetic gas among regions, and perhaps even to reallocate flowing gas among interstate pipelines.

4. Congress would surely direct the FPC to allocate gas nationally if it were to approve any LNG system for the delivery of North Slope natural gas, which would require large areas of the United States to receive new gas supplies by displacement rather than directly. Approval of a MacKenzie or Alcan system without a western leg would also strengthen the demand that the FPC have direct allocation authority. Such an outcome would be unfortunate because any non-market allocation system would blunt the incentives of transmission companies and gas utilities to solve their own supply problems.

5. It is possible to make some broad generalizations about both the commodity value and the cost of gas on a national scale. The demand for gas can be separated into three main components: (a) a premium market in which only electricity is a competitive energy source, (b) an intermediate market in which refined petroleum products (distillate fuel oil, naphtha, propane, etc.) are effective substitutes, and (c) the "black fuels" market in which natural gas can displace coal and residual fuel oil only when it is cheaper.

6. The intermediate market, which is composed of household and small commercial space heating, and use for crop drying, in combustion turbines and for chemical feedstocks

(plus utility boiler fuel in times and places with severe air quality problems), is by far the major part of total consumption, so that all plausible projections of United States natural gas supplies through 1990 fall into this intermediate segment of the demand function. For this reason the long-term commodity value of gas will be equivalent, more or less, to the cost of refined petroleum products. Assuming that the real price of imported crude oil remains about the same as it is today, we can anticipate a long-term demand price for gas of \$2.50 to \$3.00 in 1976 dollars.

7. The demand price for gas will be somewhat higher than that of distillate fuel oil if total gas supplies continue to decline over the period, because the alternative to gas for many consumers will not be simply the substitution of a petroleum product but will also include the cost of converting or replacing existing gas-burning equipment.

8. The average (rolled in) cost of gas will be just about equivalent to this commodity value or demand price. Pipelines and distributors will continue to get some quantity of gas purchased on long term contracts or controlled at less than its commodity value. They will therefore be able to augment these low price conventional supplies with just enough high cost gas "supplements" at \$4, \$5, \$6 or more per Mcf, to bring their average price up to the demand price.

9. For this reason deregulation (or the level of regulated gas prices) can not be expected to have a great effect on the average price consumers pay for gas.

It might, however, have a powerful influence on how much gas is available at that price (although the direction) of this influence is not obvious -- see footnote), and upon the economic cost to the nation as a whole of its gas supply.

(The national economic cost would be lowest under deregulation, but the larger part of the net benefit would be captured by gas producers rather than by consumers.).

10. The most certain and economical source of additional gas for premium and intermediate markets are the volumes now being burned under industrial and electric utility boilers and as refinery fuel. End use controls

The question hinges on the responsiveness of conventional gas supplies to price. If supply is relatively price-inelastic, the main impact of deregulation or higher wellhead prices would be to transfer revenue to gas producers and royalty owners at the expense of the pipelines and distributors. Since the latter would otherwise have used this revenue to finance the purchase or production of high-cost gas supplements, total gas supply would be less than it would be at the old regulated prices. On the other hand, if the supply of new reserves of conventional gas is highly responsive to price (as I believe is more likely), an additional dollar paid to the gas producers will elicit a greater volume of gas than the same dollar spent on such projects importing LNG or manufacturing SNG from coal or oil.

by the FPC and state authorities are already encouraging such a shift. But in order to employ existing reserves most efficiently around the year, elimination of interruptible sales for low-priority use must go together with investments in storage facilities and in increased peak deliverability in the field. Incentives for the latter adaptation are now blunted by price controls, but added storage is probably a worthwhile investment for almost every gas transmission company or utility.

11. The main supplemental sources of gas appear to be Canadian pipeline imports, LNG imports, Alaskan natural gas and SNG from coal and petroleum.

12. The price of future Canadian imports is reasonably predictable, but their volume is not. The Canadian federal government and Alberta have adopted an explicit commodity value standard for gas pricing in both domestic and export markets (though it is being implemented more slowly for Canadian consumers), and there is little reason to believe that this policy will be changed.

13. The approximately 60 TCF of presently proved reserves in the Western Provinces are sufficient to serve projected Canadian demand plus existing export commitments for about 10 years without creating deliverability problems. A continuation of recent Alberta discovery

trends may be sufficient to assure that existing export contracts will in fact be honored. But there is no development, short of huge discoveries (perhaps another 60 TCF) in the Arctic that would be likely to induce the Canadian government to approve new export commitments.

13. The sufficiency of present supplies to Canada for about ten years, means

that any Mackenzie or Polar pipeline will be superfluous to Canada's needs for at least that period, unless reserve volumes justifying exports are developed. This implies that there is no urgency for Canada in an early determination regarding the desirability, scale or timing of a Mackenzie Valley pipeline.

14. Large LNG import projects, coal gasification, and facilities to deliver gas from the Alaskan (and/or Canadian) Arctic to Lower 48 markets share several features which raise serious questions about their economic viability or practical feasibility. Each of them requires large, "lumpy" investments -- in the billions or tens of billions of dollars -- and involves unproved technology or a substantial scale-up of proved technology. Some proposals involve a unique physical or institutional environment (e.g., the Arctic Gas proposal and Indonesian LNG)

in which no engineering projects of their magnitude has ever been attempted. Each of them involves numerous regulatory jurisdictions, including more than one sovereignty or quasi-

sovereignty (states and provinces). Each of them involves major environmental and safety issues, real or imagined, usually in more than one regulatory jurisdiction.

15. The construction and operating cost projections offered by the proponents of each of these gigantic capital-intensive projects are already near the margin of economic feasibility, even assuming the absence of major delays, technological or engineering false starts, or cost overruns.

16. Recent experience with military procurement, nuclear power plants, the Trans-Alaska pipeline and other large custom-engineered construction projects indicates that all the large supplemental gas projects are exceptionally vulnerable to delay and cost-overruns, if not to non-completion.

17. The scale of these projects typically exceeds the net worth of their sponsors, precluding conventional secured financing. Uncertainty about construction costs and completion dates, aggravated by political and licensing uncertainty make no-recourse debt financing equally improbable. Each project therefore probably requires government loan guarantees (increasing their vulnerability to political opposition) and/or all-events tariffs, which state commissions are unlikely to approve.

18. In short, I believe that the odds are against any supplemental gas supply facility with a total projected capital cost of greater than \$1 billion. The chances that all the supplemental gas projects considered necessary to provide an adequate gas supply to any region (e.g., California) will be actually completed, is nil.

19. Of the three proposals for transporting North Slope gas, the Alcan project is in my judgment the most credible, even though the comparison of pro-forma cash flow projections would seem to favor Arctic Gas. By using conventional pressures, pipeline size and construction technology, already developed transportation corridors, and existing pipeline routes and systems in Western Canada, Northwest Pipeline's Alcan proposal avoids or mitigates the major sources of cost overruns. Moreover, Alcan is the only proposal of the three which does not depend for its feasibility on larger volumes of gas than can be assured from presently proved reserves.

20. The Alcan proposal is probably the least vulnerable of the three to political opposition on regional or sectoral grounds. It does not involve the siting and safety issues of the LNG system, but unlike Arctic Gas, it is favored or at least is not vehemently opposed by any of the states or provinces (including Alaska and Alberta) which it must transit. The Alcan concept is the one favored by the major U.S. environmental organizations. Native claims issues, moreover, seem to be closer to resolution in the Yukon than in

the Northwest Territories.

21. The synthesis of pipeline quality gas from petroleum does not suffer from most of the handicaps of coal gasification or of the other capital-intensive sources of natural gas supplements. Here again, as in the case of the alternatives for transportation of Alaska gas, a priori cost comparisons may be deceptive. SNG from oil appears to be more costly than SNG from coal, but this comparison ignores the fact that it is a proved technology on a commercial scale, that its optimum economic scale of plant is an order of magnitude smaller, and that the feedstock is (barring a new embargo) available in unlimited quantities.

22. The smaller scale and general abundance of feedstocks for SNG plants using petroleum fractions (naphtha or LPG) means that each plant can be located within the consuming state, (freeing it from FPC jurisdiction), within the service area of the pipeline or utility which distributes it (reducing local opposition), and in a site chosen for environmental acceptability (rather than one dictated by location of the resource or by proximity of a deep water harbor). For all of these reasons, I suspect that the West Coast gas industry's ultimate recourse when almost everything fails (as it probably will) is the construction of decentralized SNG plants using naphtha feedstocks from overseas (or even Alaskan) topping plants which ship their residual crude oil fractions to Japanese or Atlantic customers.

23. The best bets for new pipeline gas supplies, I believe, come from state-of-the-art technologies and scales of effort, not from ten year leaps into the future and tenfold leaps in size. The source of gas that best meets this standard is conventional natural gas conventionally extracted. Exploration for gas (and for oil, which is found in similar environments by the same techniques) is an entirely different kind of business from producing synthetic fuels or building major gas transmission projects or the maximum scale electrical generating plants. The minimum unit of physical capital, a single wildcat well for instance, ranges in cost from tens of thousands of dollars to several millions -- a scale on the order of one thousand times less than the investment thresholds for coal gasification, oil shale, nuclear power or Arctic gas transmission.

24. There are literally thousands of enterprises in the oil and gas producing industry, with perhaps hundreds that are large enough and progressive enough to stand on the cutting edge of new technology. The journey to new frontiers of gas exploration and recovery, whether they are technological frontiers, deeper or stormier water, permafrost or deep rocks, can be taken in small steps, with part of the industry consolidating information and techniques from the last step while other firms take the pioneering risk.

Onshore, the payoff to exploration investment can be a matter of weeks, and is seldom more than two years. Off-shore and in the Arctic, it may be three, five or seven years, but seven years is probably the minimum lead time for the big-ticket gas supply projects.

25. Regarding the potential price-responsiveness of natural gas supply, there are an incredible number of different opinions. It is obvious, however, that FPC price controls are not a major obstacle to exploration and development in any state large enough to have a significant intrastate gas market: these include present net exporters of gas like Texas and Louisiana as well as net importers like California. It has now been three years since the Arab embargo and the energy price revolution, so that some evidence one way or another on the price responsiveness of conventional onshore gas supply ought to be available before long.

26. Price controls on gas may or may not be an effective deterrent to development of new gas resources on the Outer Continental Shelf, but they are not the major deterrent. It is unfortunate that environmentalist opposition to energy development has been most effective here, because the OCS oil and gas will be in my judgment/least environmentally harmful source of large new supplies of primary energy for the United States, as well as the least costly in terms of real economic resources.

27. In summary, small seems indeed to be beautiful in energy supply alternatives. Or, at least, small is practical given today's political and financial realities. At the same time, I would urge along with the ecologists that diversity is stable, and so is decentralization. Diversified and decentralized systems are also more predictable in the aggregate. For this reason, a strategy for gas supply which depends mainly on a few large coal gasification and Eastern Hemisphere LNG projects and on the Arctic Gas pipeline stands a large risk of total failure. A strategy which puts even half of the capital projected for these projects into storage and increased peak deliverability, into conventional and modestly innovative onshore and offshore gas exploration, into SNG from naphtha facilities, into small LNG projects (as in Cook Inlet), and into a minimum scale transportation system for North Slope gas (like the Alcan system) may not yield the grandiosely optimistic projections for 1985 or 1990 gas supply which industry and government agencies like to put on their charts. Such a strategy will, however, surely and predictably produce enough gas at acceptable prices to serve the premium markets, and will continue to make some contribution to satisfy the intermediate market.

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ECONOMIC ANALYSIS OF ALASKAN ROYALTY GAS CONTRACTS

a report to

STATE OF ALASKA: THE LEGISLATURE

JENSEN ASSOCIATES, INC.

**Boston, Massachusetts
Washington, D.C.**

ECONOMIC ANALYSIS OF
ALASKAN ROYALTY GAS CONTRACTS

A Report to
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I. INTRODUCTION AND SUMMARY

INTRODUCTION

Three contracts for the sale of the State of Alaska's royalty gas from the leases on the Prudhoe Bay oil and gas field have been negotiated by the State of Alaska with Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company. These contracts must be approved by a majority of each House of the Alaska State Legislature. The Legislative Affairs Agency, acting on behalf of the Alaska State Legislature, has retained Jensen Associates, Inc. to perform an economic analysis of the State of Alaska's Proposed Royalty Gas Sales Agreements. The economic analysis of these proposed agreements is presented in this report.

The purpose of our analysis is to determine if the contracts protect the interests of the State of Alaska. In this analysis, we were asked to examine two questions:

1. Is Alaska protected if the El Paso project is not the one selected? and
2. If the El Paso project is approved, does the contract provide favorable value to Alaska?

SUMMARY

Alaska will receive favorable benefits from royalty gas either by obtaining the highest possible price from the sale of gas into interstate markets or for soundly based use in Alaska. Because of the large volumes of royalty gas available and because of the possibility of additional gas discoveries near Alaskan markets for natural gas, the more important question for this analysis appears to be the price that Alaska can receive in interstate markets. Second, it is necessary to analyze the flexibility built into the contract to allow Alaska to use the gas for its own needs.

There is significant uncertainty about the price of the Prudhoe Bay royalty gas. Table I-1 illustrates this range where it shows the possibility of prices ranging from \$0.20 to above \$2.00 per Mcf. The uncertainties in the value of the gas and thus risks to Alaska are caused in part by uncertainties in energy markets, but much more importantly are caused by the uncertainties surrounding the legislation and regulation of natural gas.

The initial deliveries of Prudhoe Bay natural gas will occur at a time when--in our view--significantly increasing prices for energy world-wide are likely. Between now and 1985, we believe that the Organization of the Petroleum Exporting Countries (OPEC) is not likely to lose control of international oil pricing despite occasional periods of surplus and some degree of internal dissention within the organization. Beyond 1985, however, the possibility exists for sharply higher real world oil prices. This would result from continued growth of world oil demand combined with growing producing capacity limitations in many OPEC countries, thereby creating the conditions for shortage pricing by those few national oil suppliers who can still respond to world demand growth.

Between now and 1985, U.S. energy prices should rise because of (1) OPEC oil prices rising to keep pace with inflation in industrialized countries, (2) a rise in U.S. oil prices to approximate world oil levels as the current domestic price controls are relaxed or eroded, and (3) the U.S. beings to use higher energy prices to foster energy conservation as do Japan and the countries of Western Europe. Beyond 1985, much greater price uncertainty exists, but in our view, rising real prices are the most likely possibility.

The value of Prudhoe Bay gas netted back to the wellhead from No. 2 oil market values in California and the Midwest are shown in Table I-1 for 1980. Because the market price of No. 2 oil is expected to increase, and perhaps sharply, over the

TABLE I-1

RANGE OF POSSIBLE WELLHEAD PRICES FOR
PRUDHOE BAY NATURAL GAS

1980

<u>Market Values via El Paso Project*</u>	<u>Dollars per million Btu</u>
Competing with No. 2 oil**	
Mid West	0.94
California	1.22
Competing with coal based synthetic natural gas	
Mid West	2.71 - 3.05
<u>Regulated Values</u>	
Opinion No. 770 National Rate on new gas	
\$1.42 plus \$0.01 per quarter from October 1, 1976	1.56***
Possible Alaska Area Rate****	0.20 - 0.45

* Assuming F.P.C. staff estimate of gas capital transportation costs and netback value for fuel cost.

** Equivalent Btu value with No. 2 oil giving natural gas a 10 percent form value premium.

*** If the prices are regulated using more recent drilling costs and discovery data, the cost based price should rise above that shown here.

**** Computed with only Alaska data including associated gas.

twenty-year contract life, the netback market values will be higher than the 1980 wellhead price shown.

The greatest uncertainty about price is caused by uncertainty over legislation and regulation. If new gas is deregulated and Prudhoe Bay gas qualifies as new gas, as it will under some bills, then market value pricing will prevail. If wellhead prices continue to be regulated, Prudhoe Bay prices remain uncertain. Recent national rate opinions by the Federal Power Commission (F.P.C.) have specifically excluded Alaska and Hawaii from both the rates and the cost calculations that underlie the rates. If Alaska is included in the national rates as currently computed based only on non-associated gas, the prices will change little from current calculations because of the small amount of Alaska non-associated gas. However, if the vintaging formula under the most recent national rate decision, (Opinion 770-A), were to prevail, in which well spud-date determined the vintage, then some gas would not qualify for the new gas rate. However, vintaging is not the source of great price uncertainty. If regulation does not include Alaska in the national rate and an area rate is set for Alaskan reserves as the associated gas of Prudhoe Bay sets the possibility for lower wellhead prices. Since some of the costs of exploration and development will be allocated to oil for an associated gas discovery, and the Prudhoe Bay field is large, the costs per Mcf of gas is low as shown in the sample calculation in Table I-1. However, such a calculation assumes that the F.P.C. will depart from its recent tradition of excluding associated gas from its national rate calculations as had been done earlier in F.P.C. history. In any case, regulatory decisions can have great impact upon the value to Alaska of the Prudhoe Bay royalty gas.

CONCLUSIONS

The termination clauses built into the contracts protect Alaska in the event that the El Paso project is not approved or that there is excessive delay in approvals.

If the El Paso project is approved or if the terms of the contract prevail under another pipeline route, then the pricing provisions and the reservation clauses become important. The most important question is how does the contract protect Alaska's interest in the face of considerable price, regulatory, and legislative uncertainty. Our conclusions are:

- Future wellhead prices of Alaskan natural gas will be determined either through regulatory processes as they are now, or through price negotiation should Congress deregulate natural gas.
- In the event of deregulation, the contract will play a significant part in price determination. The pricing clauses with periodic redetermination, assuming a proper clarification of the ambiguity of redetermination relative to Section 6.3, are sound.
- If wellhead price regulation remains in force, the role of price determination will remain with the Federal Power Commission, or possibly with Congress and the contract itself can do little to influence the price. It is important to recognize that the contract has adopted a passive stance, having tied itself to the efforts of the producers in obtaining a ceiling price. Since no real precedent for price setting of Alaskan associated gas exists at present within the F.P.C., and since the strength of the producers' gas is not known, the state might have a stronger future position by setting its own price precedent now in this contract under Section 6.2.
- In addition, there is ambiguity in the interpretation of the price including severance taxes on royalty gas under regulation. This may keep severance taxes or their equivalent from being collected on the royalty gas at a loss of \$50-\$150 million dollars. The ambiguity needs clarification either in the contract or through Alaskan severance tax legislation.

The clauses reserving gas for Alaska are very good and provide significant flexibility. The State can make both time and location exchanges when they provide a better value for natural gas to Alaska than by selling interstate.

Finally, favorable value of the gas will be brought to Alaska more by action outside the contract in legislation and regulation than by the contract itself.

II. SUMMARY OF CONTRACT

The proposed sales by the State of Alaska of 2.6 trillion cubic feet of Prudhoe Bay royalty gas to Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company are designed to help Alaska in three ways:

1. Promote the construction of a trans-Alaska gas pipeline system, with the associated benefit of making gas available close to people and industry;
2. Establish a gas pricing structure favorable to Alaska for sale of royalty gas outside the State; and
3. Protect future needs for gas within Alaska.

A brief review of the contract mechanisms designed to implement the above goals follows.

PROMOTE TRANS-ALASKAN PIPELINE ROUTE

Article I of the contracts (entitled Support for Trans-Alaska Pipeline) requires both the State of Alaska and the royalty gas purchasers to work actively for the selection of a trans-Alaska gas pipeline system. The provision in Article XI (Conditions Precedent) that the royalty gas contracts may be terminated by directive of the Governor of Alaska if another route is approved appears to give sufficient motivation to the buyer to work hard in its endeavors to seek passage of a trans-Alaska pipeline route. Alaska's interests are adequately protected on this point. Alaska may choose to support any trans-Alaska pipeline route, although the State has indicated a preference for that proposed by El Paso Alaska Company. Alaska may also terminate the contract if pipeline route approvals are not forthcoming by December 31, 1978 or if a route other than El Paso's is approved.

ESTABLISH FAVORABLE GAS PRICING STRUCTURE

In order to obtain favorable prices for Alaskan royalty gas, the contracts establish different pricing mechanisms depending upon the regulatory or non-regulatory status of the gas. Article VI (Price) identifies three regulatory situations which might occur:

Section 6.2: Federal Power Commission has jurisdiction at the time of first deliveries over royalty gas resale rates in interstate commerce;

Section 6.3: No Federal Power Commission rate-regulation exists for royalty gas for interstate resale at the time of first deliveries; and

Section 6.4: Federal Power Commission deregulation occurs after first deliveries of royalty gas have begun.

If Federal Power Commission jurisdiction applies, the initial price of the royalty gas is to be the highest applicable rate allowed and never less than the price paid producers for their gas from the same reservoir for comparable interstate sales. If regulation does not apply, then the initial price is to be the highest interstate price being paid producers for similar sales from the applicable Prudhoe Bay leases.

If deregulation occurs after first deliveries, the price is subject to redetermination with a provision for arbitration in the event that price accord can not be reached. Annual redetermination may occur thereafter at the request of either buyer or seller. In all cases, the gas price is adjustable up or down if the gross heating value is more or less than 1,000 British Thermal Units (Btu's) per cubic foot.

Since no specific prices are established in the contracts, our analysis focusses on three issues:

1. The likely U.S. and world energy marketing context facing Alaskan royalty gas in the period 1980 and beyond. Chapter III examines energy economic trends in the U.S. and world pressures on energy prices in that period;
2. The market value of Alaskan royalty gas at the time of actual deliveries (Chapter III); and
3. Possible pricing formulas that may apply in the event of price regulation existing at the time of royalty gas deliveries (Chapter III).

Two additional aspects of natural gas pricing--vintaging and severance taxes--are considered in our analysis.

Vintaging refers to the date assigned to an interstate gas sale to determine the applicable regulatory price. Severance taxes are state-imposed producer taxes on gas extraction. The implications of vintaging and severance taxes to the contracts are discussed in Chapter III also.

PROTECT ALASKA'S FUTURE GAS NEEDS

Alaska clearly desires to retain future access to Prudhoe Bay gas for internal requirements. Under Article III (Quantity), the State has the right to reduce the quantity of royalty gas for interstate sale by varying percentages throughout the life of the contract. Alaska may retain 25% of the royalty gas for the first five years and increase this amount by 25% in each subsequent five-year period over the life of the contract. Alaska also has the right to change the percentages of royalty gas taken for internal needs upon a 24-month written notice as well as to export products, such as ammonia, manufactured from its retained gas. While the three contracts also contain "take-back" provisions enabling the buyer to recoup the quantities retained by the State to meet internal needs, this applies only if additional surplus royalty gas is available. Chapter IV of this report considers possible situations in which Alaska retains royalty gas for internal usage.

Finally, in reviewing the royalty gas contracts, some concerns arose regarding specific contract language. While relatively minor, these points are outlined in Chapter V. It is also recognized that in the process of negotiating a contract, both parties must "give and take" on the various issues. Since Jensen Associates, Inc. was not involved in the negotiating process, we acknowledge that some of the matters on which we comment here may have been dealt with in the negotiations themselves. Nevertheless, the issues are outlined in the report in accordance with our obligation as consultants.

III. SALE OF PRUDHOE BAY NATURAL GAS

Alaska wants the most favorable price it can obtain for its royalty gas sold into interstate commerce. As we look ahead, we see considerable uncertainty about the price of energy in general and specifically about the price of natural gas in Alaska which may prevail when initial deliveries of royalty gas occur and for the subsequent twenty years over the term of the contracts. These uncertainties were apparently understood in the negotiation of the royalty gas contract. The contract pricing clauses simply state that the price shall be set at the highest price determined for comparable contracts, and if deregulation occurs, periodic price redetermination is established.

The uncertainty in price and thus risks in the payments to Alaska are created by forces outside the contract. These forces are markets and the course of natural gas regulation and/or legislation at the Federal level. This contract can influence the course of markets, regulation or legislation only slightly. However, the Legislature of the State of Alaska needs to be aware of and understand the causes behind these very real uncertainties about the price of Alaskan gas and their economic risk as it evaluates these contracts. Consequently, our evaluation of the contracts focusses more on contractual ability to adapt to changing price circumstances than upon the ability of the contracts to influence the prices.

In order to understand the extent and cause of the uncertainty about price of Alaskan royalty gas, we describe below the movement of energy markets in the United States and the world from 1975 to 1990, market value pricing of Alaskan gas which would prevail if deregulation of the wellhead price of gas were to apply to Prudhoe Bay gas, costs of alternate forms of energy for natural gas pipelines, and the impact and differences in pricing which regulation by a body such as the Federal Power Commission could bring to the price of Alaskan royalty gas.

ENERGY MARKETS IN THE UNITED STATES AND THE WORLD, 1975-1990

The Organization of Petroleum Exporting Countries (OPEC) has demonstrated since late in 1973 that it has considerable power to set the price of crude oil unilaterally in world markets. Western Europe, Japan, and increasingly the United States, as natural gas production declines, are dependent upon this imported oil which is the incremental source of energy in the industrialized nations and tends to set the price of all forms of energy. Consuming nations can influence price through controls or taxes to be more or less than the world market crude oil price. But controlling price below world market levels requires the nation to have its own energy production, as is true of the United States.

OPEC Production and Pricing

Table III-1 is the estimate of the world oil trade to 1985. The growing demands for OPEC oil production make a break-up of the cartel unlikely. We expect the United States to continue to rely upon imported oil, and, thus, be heavily subject to the world price of oil. The production of oil from OPEC nations should increase steadily but within productive capacities. In particular, Saudi Arabia, a country with the largest oil reserves in the world, should be able to accommodate increases in demand without strain to the mid-1980's.

The price of OPEC oil is not expected to decline, rather we expect the oil producing nations to attempt to maintain the value of their oil. As inflation continues in the industrial nations, the price of oil should increase apace to the mid-1980's.

Forecasts of oil, supply, demand and price are subject to an increasing range of error the further into the future the forecast is made. However, the contracts for royalty gas are scheduled to run for twenty years beyond the initial deliveries of gas which should occur sometime between 1980 and 1985.

TABLE III-1

WORLD OIL TRADE

(Million barrels per day)

	<u>1975</u>	<u>1980</u>	<u>1985</u>
IMPORTS			
United States	5.8	11.5	11.5
Western Europe	12.4	12.0	14.0
Japan	4.9	6.0	8.0
Net to Balance ^{1/}	4.3	6.5	9.5
OPEC PRODUCTION			
Total	27.4	36.0	43.0
Saudi Arabia ^{2/}	7.1	10.0	12.0

^{1/} Includes net imports (exports) of the Non-OPEC developing countries, the Sino-Soviet countries, OPEC internal consumption, stock changes, and adjustments.

^{2/} Includes 50% of Neutral Zone.

Source: Jensen Associates, Inc.

Thus, most of the gas under these contracts will be delivered after 1985, the time horizon to which most international oil forecasters have recently chosen to limit their estimates. In order to understand how energy prices will behave in the latter part of the 1980's and beyond, it is important to review the likely trends in world oil consumption compared with the development of both non-OPEC and OPEC supply.

Oil will be a major source of energy into the 1990's and beyond. Even though non-traditional energy sources may begin to grow rapidly, they do so from a small base so that continued economic growth needs to be, for some years after 1985, fueled by oil. But as oil demand on OPEC production increases, production capacity limits for most of the OPEC countries could very likely be strained. It is not hard to see oil demand bumping up against capacity constraints most everywhere except in Saudi Arabia after 1985. If this were to happen, the conditions would be set for another dramatic upward shift in the price of oil. It is also possible to envision very effective conservation efforts and accelerated alternate energy supply programs being developed, in which case the strains on OPEC production capacity would not be severe and oil price increases would be moderated. However, it is difficult to envision a decline in OPEC production in the decade following 1985 which would place downward pressure on world oil prices unless the industrialized nations of the world were to sink into depression.

As the time of initial deliveries of royalty gas nears, the post-1985 energy supply and demand balances will become clearer. These forecasts should begin to have a significant impact upon domestic U.S. energy prices and government policy. The post-1985 conditions are unclear today and the range of uncertainty about energy prices is high. However, forces that would create sharply higher prices seem more likely than a worldwide depression that might force oil prices downward.

U.S. Price Controls

At the current time, the price of oil in the United States is controlled by the Federal government at levels below the world price. However, the price for "new" oil is higher than for "old" oil in order to encourage further exploration and the development of additional supplies. The stated intention of the Energy Policy and Conservation Act is to allow the price of oil to increase and eventually for it to be decontrolled. Either as "new" oil becomes an increasing share of supply or oil price is decontrolled, the price of oil will increase more rapidly in the United States than in world markets as the U.S. prices catch up to the world prices.

U.S. Energy Conservation

There is a developing consensus in the United States that the conservation of energy is an important national objective. Currently, there is no equivalent consensus on how this objective is to be reached. There have been some attempts to use engineering standards mandated by regulation or legislation to promote energy conservation such as mileage requirements for new cars. Meanwhile, government policy has concentrated on keeping the price of energy low.

Other countries, such as Japan and those in Western Europe who have a longer history of oil imports than the United States, have relied upon the price system to bring about energy conservation. These nations increase the cost of energy to the consumer above world oil prices by taxation. Energy consumption in Japan and Western Europe is below that of the United States by more than can be explained by a difference in the standard of living. The use of the price system to bring about energy conservation has proven to be successful in other nations.

As the United States develops an energy conservation program, an increasing reliance upon higher energy prices to bring about conservation is to be expected. This, too,

should reinforce both the OPEC determined price increases, the price increases of oil and other energy forms in the United States as oil market levels are approached, to bring about an even greater increase in the price of energy for the United States.

Conclusion

OPEC oil pricing, the phase-out of oil price control in the United States or an increasing proportion of "new" oil, and greater reliance upon higher prices to foster energy conservation all point to increased energy prices in the U.S. The extent of these increases is uncertain. However, the greatest uncertainty is about prices in the mid-1980's. The potential for oil demand running hard against world productive capacity exists. Sharply increased prices would result. But, if the industrialized nations can aggressively conserve energy and develop sources other than oil, or if economic growth falters, then OPEC oil production capacity will not be under the same stress.

MARKET BASED VALUES OF NATURAL GAS

In the event of deregulation, market forces would determine the field price of Alaskan North Slope gas. One way to anticipate this price is to forecast the market price of alternate fuels and to netback to the North Slope using the costs of transporting the gas to market. The theory is that the price of natural gas at the market (e.g., Los Angeles) would tend toward a level related to the price of alternate fuels, and that the field price resulting would be the market price less the cost of transmission.

We have computed the netback value of Alaskan North Slope gas based on the market prices of competing alternate fuels in Los Angeles and Chicago. This section describes the method and the results of this analysis.

Number Two Fuel Oil

The calculations which compare natural gas with fuel oil are based on the projected prices of No. 2 oil in Los Angeles and Chicago. In the case of Los Angeles, it was assumed that No. 2 oil would be refined primarily from Alaskan crude, priced to be competitive with Saudi Arabian light landed in Houston. The present price of Saudi Arabian light is \$12.09 F.O.B. Ras Tanura. This price can be inflated at 5% per year to 1980 and, with the addition of transportation costs, terminal costs and refinery margins, yields a projected price for No. 2 oil in Houston in 1980. Netting back to Los Angeles via crude pipeline results in a price for No. 2 oil refined from Alaskan crude and delivered in Los Angeles. A 10% premium must then be added to account for the fact that natural gas is often preferable on a Btu basis to No. 2 oil.

To compute a price for No. 2 oil in Chicago, we added to the price of No. 2 in Houston the cost of transporting the fuel by product pipeline to Chicago. Again we added 10% to reflect a premium for clean-burning natural gas.

In both Chicago and Los Angeles, it was assumed that the relevant price comparison was between No. 2 oil at the refinery

rack and natural gas at the city gate. The cost of local delivery to large volume industrial users was assumed to be small and approximately equal for either fuel.

SNG from Coal

Current estimates for the cost of producing gas from coal form a range of between \$3.00 and \$4.00 per million Btu. To obtain a 1980 price for coal-based SNG, we selected \$3.50 as a middle-range figure, inflated it at 8% per year for five years, and added projected transportation costs.

Netback Value

The netback value is computed in the following way. Suppose the projected market price of No. 2 in Los Angeles is \$3.50 per MMBtu. Adding 10% results in a market value for natural gas of \$3.85 per MMBtu, competing against No. 2 oil. In other words, pipelines could charge gas distributors in Los Angeles up to \$3.85 per MMBtu, the price of the competing incremental fuel source. The field price in Alaska is then determined by subtracting from \$3.85 the cost of transporting the gas from the field to Los Angeles. If the transport costs were \$2.00 per MMBtu, then the price that Alaska could charge for its royalty gas in the field would be \$3.85 minus \$2.00 equals \$1.85 per MMBtu.

It should be noted that transportation costs include the cost of gas used and lost along the respective routes. Consequently, transportation costs vary with the netback value which in turn varies with the projected market price of the competing fuel. In short, the higher the value of Alaskan North Slope gas, the more expensive it is to transport.

Tables III-2, III-3, and III-4 show netback values computed for the El Paso project and the Arctic Gas project separately.

Strictly speaking, netback values show what price would prevail for natural gas (regardless of source) in each market, assuming insufficient gas is available to replace the alternate

TABLE III-2

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS

BASED ON NO. 2 OIL

1980

(Dollars per million Btu)

El Paso Route

Price of No. 2 Oil (Incl. Premium)* - El Paso Transportation Costs** = Netback Value

Chicago	\$3.34	\$2.40	\$.94
Los Angeles	\$3.10	\$1.88	\$1.22

Arctic Route

Price of No. 2 Oil (Incl. Premium)* - Arctic Transportation Costs** = Netback Value

Chicago	\$3.34	\$1.68	\$1.66
Los Angeles	\$3.10	\$1.40	\$1.71

* Assumes that the current price of Saudi Arabian light (\$12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

** Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON NO. 2 OIL
1985

(Dollars per million Btu)

El Paso Route

Price of No. 2 Oil (Incl. Premium)* - El Paso Transportation Costs** = Netback Value

Chicago	\$4.59	\$2.61	\$1.98
Los Angeles	\$4.27	\$2.08	\$2.19

Arctic Route

Price of No. 2 Oil (Incl. Premium)* - Arctic Transportation Costs** = Netback Value

Chicago	\$4.59	\$1.79	\$2.80
Los Angeles	\$4.27	\$1.50	\$2.77

* Assumes that the current price of Saudi Arabian light (\$12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

** Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

TABLE III-4

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON SNG FROM COAL
1980
(Dollars per million Btu)

El Paso Route

Price of SNG Delivered^{*} - El Paso Transportation Costs^{**} = Netback Value

Chicago	\$5.46	\$2.75	\$2.71
Chicago	\$5.46	\$2.41 ^{***}	\$3.05

Arctic Route

Price of SNG Delivered^{*} - Arctic Transportation Costs^{**} = Netback Value

Chicago	\$5.46	\$1.87	\$3.59
Chicago	\$5.46	\$1.61 ^{***}	\$3.85

* Current estimates place the cost of producing SNG from coal of between \$3 and \$4 per MMBtu in 1975 dollars. We have used \$3.50/MMBtu and inflated at 8% per year to 1980. Cost of transporting SNG assumed to be 32¢/MMBtu.

** Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

*** Assumes gas lost or used as fuel in transit is valued at \$1.00/MMBtu.

fuels. Of course, if all Alaskan gas were channeled into Los Angeles, saturation would occur and Los Angeles' market price of gas would fall. However, in the broader context of the national market, (which size is currently on the order of 55 billion cubic feet per day), the additional 3.5 billion cubic feet per day anticipated from Alaska may not be sufficient to render uneconomical even the most expensive alternate fuel sources now being contemplated.

Contracts

Section 6.3 of the contracts states that in the event of deregulation, prior to first deliveries of Alaskan North Slope gas, "the initial price for gas delivered hereunder shall be the highest price being paid by any interstate gas purchaser for gas under contracts. . . ." This provision appears adequate to insure that Alaska receives the full netback value based on the appropriate competing alternate fuel source, providing that the North Slope producers have marketed their gas judiciously; and with the price incentives inherent under deregulation, there is every reason to believe that they would do so.

Section 6.4 provides, moreover, for price redetermination in the event that the price of gas is regulated at the time of first deliveries and subsequently deregulated.

These two sections together provide that Alaska receives full market value for its royalty gas under deregulation, providing vintaging allows, whether or not deregulation occurs before or after the date of first deliveries. Moreover, inasmuch as Alaska contemplates taking royalty gas in kind, and selling it in the field, netback pricing serves to illustrate the market price potentially available to Alaska for its royalty gas.

COST-BASED REGULATION OF ALASKA GAS PRICES

In the event the sales of Prudhoe Bay gas contemplated in the contracts are found to be jurisdictional by the F.P.C., the price clause (Section 6.2) provides that

1. "... The initial price . . . shall be the highest area, national or ceiling rate allowed to be paid by any interstate gas purchaser to any working interest owner . . ."
2. "The price to be paid thereafter shall be subject to all periodic changes permitted in accordance with the . . . Rules and Regulations of the Federal Power Commission . . . or such other changes in price as may be permitted by any new area, national or ceiling rates . . . which may subsequently be established."

Thus, the value of the contracts depends upon the ceiling price which may be established by the Federal Power Commission. The contracts do not specify or assume that the nationwide rate established by the F.P.C. will apply to the contract sales. On the contrary, the contracts accept in advance, whatever rate-making method the F.P.C. might apply to sales of Prudhoe Bay gas. Moreover, the contracts tie the interests of the State of Alaska to the interests of the private companies producing Prudhoe Bay gas. The State will not receive a price for its royalty gas any higher than the cost-based price which the companies can justify to the F.P.C.

The National Rate and Alaska Gas

The current nationwide wellhead ceiling price for "new" natural gas in the United States is \$1.42/Mcf (plus 1¢/quarter beginning October 1, 1976), established in F.P.C. Opinions 770 and 770-A. However, these Opinions and the earlier nationwide rate Opinion 699-H all explicitly excluded the States of Alaska and Hawaii.¹ A simple decision could be made by the Commission to delete the exclusion and thus bring Alaskan gas under the

¹Title 18, U.S.C., paragraph 2.56a (f).

nationwide ceiling. The difficulty with this approach is that the \$1.42/Mcf is a cost-based ceiling price, calculated using cost data from only the lower-48 states. That is, the exclusion of Alaska from the \$1.42/Mcf ceiling is not only a legal or procedural fact but also a computational fact. If the F.P.C. were to attempt to establish a single uniform national rate including Alaskan gas, the Commission would likely bring data on the cost of gas production in Alaska into the computation process.

One fundamental assumption underlying Opinions 699-H, 770 and 770-A is that most natural gas produced in the U.S. is from non-associated gas wells (wells which produce gas from reservoirs which do not also contain crude oil). For this reason the Opinions consider data on the drilling costs and drilling footage of gas wells only. All data on oil wells (many of which also produce gas) are excluded. If the F.P.C. were to revise the national rate to incorporate data on non-associated gas wells in Alaska, the national rate would not be much affected. The number of Alaskan non-associated gas wells and the quantity of Alaskan non-associated gas reserves are not large enough (relative to the national total) to have a significant impact upon the calculation of the national rate.

However, the inclusion of Alaska within the national uniform rate may be difficult precisely because of the fundamental assumption stated above, i.e. that most U.S. natural gas is produced from non-associated wells. Such an assumption, some may argue, is inapplicable to Alaska, where over four-fifths of natural gas reserves exist in conjunction with oil. For this reason, there is a reasonable possibility that the Commission will establish a separate area rate for all gas in Alaska or for casinghead gas from oil wells in Alaska.

An Area Price Ceiling for Alaska

The calculation of a wellhead ceiling price for all natural gas in Alaska, or for casinghead (associated-dissolved) gas alone, requires the allocation of costs between oil and gas. During the

long history of F.P.C. wellhead price regulation, many methods have been proposed for making such an allocation. Most of these methods have been based upon a combination of two principles:

- That oil and gas may be substituted for each other as sources of energy and are valuable because of their energy content as measured in Btu's, and
- That oil, which has traditionally sold at a higher wellhead price per Btu than gas, should receive a premium value over gas.

A brief review of F.P.C. wellhead price regulation uncovered no instance in which the Commission had actually allocated costs between oil and gas in order to set an areawide ceiling price on associated gas (called "casinghead gas" in the area rate opinions). In setting area price ceilings between 1961 and 1974, the Commission established various categories of gas according to vintage date. The calculation of the price applicable to each vintage category was based entirely upon the costs of non-associated gas production. Newer vintages of gas received higher ceilings than did older vintages, due to inflation of drilling costs and declining sizes of gas discoveries. Casinghead gas was included in the older vintage and was not vintaged in its own right. Thus, "new" casinghead gas received a lower ceiling price than did new non-associated gas.

The most recent case in which the Commission allocated costs to arrive at a separate cost of service for casinghead gas was in the Phillips Petroleum opinion of September 1960, the last of the individual producer rate cases. In the Phillips opinion, the Commission used separate methods for allocating production costs and for allocating exploration costs. Production costs on leases producing both oil and gas were allocated in proportion to the relative costs of producing oil from oil-producing leases and of producing gas from gas-producing leases. Exploration costs (which were viewed as joint costs because, at that time, the F.P.C. did not accept the concept of directional exploration) were allocated first among oil-only leases, gas-only leases and joint-product

leases on the basis of net investment in each of these three categories of leases. Then the exploration outlays assigned to joint product leaseholds were divided between oil and gas using a modified Btu method. The number of Btu's contained in crude oil produced from the joint-product leases in the test year was multiplied by 4 as an "economic factor" reflecting the then-prevailing higher market value of oil than of gas. Thus, the following fraction of joint-lease exploration costs was assigned to gas:

$$\frac{\text{Btu's of gas produced}}{(4 \times \text{Btu's of oil produced}) + (\text{Btu's of gas produced})}$$

The Commission stated that "we are of the opinion that the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs is 4, so that the cost relationship of finding one Mcf of gas to one barrel of oil will be about 1 to 24."

Estimation of Alaskan Natural Gas Ceiling Price

Keeping in mind the long span of time which has lapsed since the Phillips precedent for separating oil from gas costs, we have, nevertheless, calculated several hypothetical ceiling prices for Alaska natural gas. These were calculated under the assumption that the F.P.C. would set an area ceiling price for the State of Alaska as a whole, with no differentiation within the State. It was also assumed that the Commission would follow a method roughly analogous to the present method used in setting the nationwide rate (that is, the method used in Opinion No. 770-A) with the following modifications:

- Data pertaining to drilling cost, drilling footage and reserve additions would be drawn from Alaska's experience only. Successful drilling cost and footage would include both oil and gas wells.
- Lead times between capital outlays and start-up of production could be considerably greater than those used in calculating the Lower-48 ceiling, and
- Unit costs would be divided between oil and gas on a Btu basis, or a value-modified Btu basis.

Working entirely from published data (the same sources used by the F.P.C. in setting the nationwide ceiling price), we calculated wellhead ceiling prices which ranged from under 20¢/Mcf to about 45¢/Mcf. The higher end of this range was calculated assuming a straight Btu division of oil and gas, which is the most favorable calculation from the gas producer's standpoint. No allowance was made in these calculations for any special capital outlay for waterflood or other enhanced oil recovery operation necessitated by the removal of the natural gas drive mechanism in the reservoir.

F.P.C. Jurisdiction Over Alaska Royalty Gas

The basic presumption of government regulation of an exhaustible resource is that economic rents should be captured by the private consumers of the resource rather than by the private firms or individuals who own and produce the resource. This presumption reflects the present distribution of political power and influence between the two groups, the consumers and the producers. The purpose of setting a ceiling price based upon cost calculations is to carry out this allocation of rents.

The State of Alaska, as a public rather than a private producer and owner of resources, may not be subject to the same political arrangement which underlies cost of service regulation. That is, in addition to the legal argument that a State is not a "person" within the meaning of the Natural Gas Act, there is also an economic and philosophical argument that a State is vested with quite different and much broader social responsibilities than is a private firm. For this reason, the State may be entitled to capture a greater share of the resource rents than has been awarded by the political process to private resource producers. The contracts for the sale of Alaska royalty gas, as they are currently formulated, establish price by reference to a ceiling price established for private producers. Such pricing by reference appears to abdicate the position that the State, even if subject to regulation, should not be subject to cost-based regulation. It would

also appear to place the State in the position of accepting a regulated ceiling price established for private producers even if the State is not found subject to regulation.

As the representative of a diverse social group, the State may not wish to bind itself to prices received by private producers, because these prices may be determined without reference to the public nature of the State of Alaska.

VINTAGING

As presently written, the contracts for the sale of Alaskan royalty gas do not mention the possibility that several ceiling prices might simultaneously apply to gas from the Prudhoe Bay area. Such a circumstance could arise from whatever "vintaging" policy is chosen by the F.P.C. to apply to Alaska gas, and could have a significant impact on the value of Alaskan gas.

"Vintaging" refers to the establishment of a date--such as the date of discovery of the reservoir or date of commencement of the well--which separates the produced gas into two (or more) categories for pricing purposes. For example, the current national rate for interstate natural gas is \$1.42 (plus 1¢ per quarter) for gas produced from wells commenced on or after January 1, 1975. Gas from wells commenced between January 1, 1973 and December 31, 1974 qualifies for a price of \$.93 (plus 1¢ per annum). In this example, the date of well commencement ("spud date") is the vintaging criterion.

At the present time, Alaska is in a unique position. No existing vintaging basis clearly applies to Alaskan gas. Thus, Alaska is limited in its ability to address future vintaging treatment of royalty gas through the terms of the sales contracts. Alaska can, however, strengthen its future position by clearly understanding the implications of vintaging and being prepared to act through regulatory intervention or otherwise at a future date. This chapter attempts to clarify the vintaging issues pertinent to royalty gas contracts.

Vintaging Under the Uniform National Rate

For Alaskan royalty gas to qualify for the highest national rate, under present vintaging methods, the gas must be produced from wells spudded in after January 1, 1975.