ALASKA NATURAL GAS TRANSPORTATION SYSTEM

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

NINETY-FIFTH CONGRESS

FIRST SESSION

ON

S. J. Res. 82

JOINT RESOLUTION TO APPROVE THE PRESIDENTIAL DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

SEPTEMBER 26, 27, OCTOBER 11, 12, AND 25, 1977

Publication No. 95-73

Printed for the use of the
Committee on Energy and Natural Resources

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

NINETY-FIFTH CONGRESS

FIRST SESSION

ON

S. J. Res. 82

JOINT RESOLUTION TO APPROVE THE PRESIDENTIAL DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

SEPTEMBER 26, 27, OCTOBER 11, 12, AND 25, 1977

Publication No. 95–73

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE
98-069 O WASHINGTON : 1977

COMMITTEE ON ENERGY AND NATURAL RESOURCES

HENRY M. JACKSON, Washington, *Chairman*

FRANK CHURCH, Idaho	CLIFFORD P. HANSEN, Wyoming
LEE METCALF, Montana	MARK O. HATFIELD, Oregon
J. BENNETT JOHNSTON, Louisiana	JAMES A. McCLURE, Idaho
JAMES ABOUREZK, South Dakota	DEWEY F. BARTLETT, Oklahoma
FLOYD K. HASKELL, Colorado	LOWELL P. WEICKER, Jr., Connecticut
DALE BUMPERS, Arkansas	PETE V. DOMENICI, New Mexico
WENDELL H. FORD, Kentucky	PAUL LAXALT, Nevada
JOHN A. DURKIN, New Hampshire	
HOWARD M. METZENBAUM, Ohio	
SPARK M. MATSUNAGA, Hawaii	

GRENVILLE GARSIDE, *Staff Director and Counsel*
DANIEL A. DREYFUS, *Deputy Staff Director for Legislation*
D. MICHAEL HARVEY, *Chief Counsel*
W. O. CRAFT, Jr., *Minority Counsel*

CONTENTS

Hearings: Page
September 26, 1977 ---- 1
September 27, 1977 ---- 55
October 11, 1977 ---- 97
October 12, 1977 ---- 141
October 25, 1977 ---- 213
S.J. Res. 82 ---- 2

MONDAY, SEPTEMBER 26, 1977

STATEMENTS

Canfield, Hon. Monte, Jr., Director, Energy and Minerals Division, General Accounting Office; Accompanied by Vincent Arostegui, Project Manager; and Kevin Boland, Assistant Director ---- 40, 45
Jackson, Hon. Henry M., a U.S. Senator from the State of Washington ---- 1
Schlesinger, Hon. James R., Secretary, Department of Energy ---- 3, 6

TUESDAY, SEPTEMBER 27, 1977

STATEMENTS

Bayh, Hon. Birch, a U.S. Senator from the State of Indiana; accompanied by Eve Lubalin of his staff ---- 55, 69
Hansen, Hon. Clifford P., a U.S. Senator from the State of Wyoming ---- 55
Stevens, Hon. Ted, a U.S. Senator from the State of Alaska; accompanied by John Burnett and Jack Ferguson ---- 72, 92

ADDITIONAL MATERIAL

Fact sheet on the Alcan Natural Gas Pipeline Project ---- 57

TUESDAY, OCTOBER 11, 1977

STATEMENTS

Blair, S. Robert, president and chief executive officer, Alberta Gas Trunk Line Co., Ltd., and Foothills Pipelines (Yukon) Ltd., Calgary, Alberta, Canada ---- 102, 104
Lepape, H. L., and S. Orlofsky on behalf of U.S. gas companies supporting the Alcan Project ---- 106
McMillian, John G., chairman and chief executive officer, Alcan Pipeline Co., Salt Lake City, Utah; accompanied by Bob Blair and Bob Pierce, Alberta Gas Trunk Line Co., Ltd.; Ed Phillips, chairman, West Coast Transmission; Mark Millard, vice chairman, Loeb, Rhodes & Co.; and Paul Miller, First Boston ---- 98, 99
Metzenbaum, Hon. Howard M., a U.S. Senator from the State of Ohio ---- 97

WEDNESDAY, OCTOBER 12, 1977

STATEMENTS

Abourezk, Hon. James, a U.S. Senator from the State of South Dakota ---- 141
Altman, Hon. Roger C., Assistant Secretary for Domestic Finance, Department of the Treasury ---- 147, 158

	Page
Batinovich, Robert, president, Public Utilities Commission of the State of California, as presented by Frederick E. John	165
Bosworth, Hon. Stephen W., Deputy Assistant Secretary of State for International Resources and Food Policy, Department of State, accompanied by Phillip Trimble, Acting Deputy Legal Advisor	142, 144
Doscher, Dr. Todd M., professor of petroleum engineering, University of Southern California, Los Angeles, Calif	189
Graham, Barbara, attorney, representing the Sierra Club, Wilderness Society, National Audubon Society, and Alaska Conservation Society	181, 184
Gravel, Hon. Mike, a U.S. Senator from the State of Alaska	207
Wolf, Sidney, M., assistant professor, division of public and environmental affairs program, Indiana University at South Bend, South Bend, Ind	172, 175

TUESDAY, OCTOBER 25, 1977

STATEMENTS

Doscher, Dr. Todd M., professor of petroleum engineering, University of Southern California, Los Angeles, Calif	328
Gilbreth, O. K., Jr., director, Division of Oil and Gas Conservation, Department of Natural Resources, State of Alaska; Hoyle Hamilton, chief petroleum engineer, Division of Oil and Gas Conservation, Department of Natural Resources, State of Alaska; and Dr. H. K. Van Poollen, H. K. Van Poolen & Associates, Inc., Littleton, Colo.; accompanied by Robert H. Loeffler, Esq., Isham, Lincoln & Beale, Washington, D.C	216, 224
Hansen, Hon. Clifford P., a U.S. Senator from the State of Wyoming	213
Houlston, E. G., manager, reservoir engineer, BP Alaska, Inc., San Francisco, Calif	322
Jackson, Hon. Henry M., a U.S. Senator from the State of Washington	213
Koch, Dr. Howard A., manager, engineering department, North American Producing Division, Atlantic Richfield, Dallas, Tex	231, 238
Koonce, Dr. K. T., operations manager, Western Production Division, Exxon U.S.A., Houston, Tex	317

APPENDIX

Additional material submitted for the record	423

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

MONDAY, SEPTEMBER 26, 1977

U.S. SENATE,
COMMITTEE ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 10 a.m. in room 3110, Dirksen Office Building, Hon. Henry M. Jackson, chairman, presiding.

Present: Senators Jackson, Metzenbaum, McClure, Domenici, Laxalt, and Stevens.

Also present: Betsy Moler, counsel; and George Dowd, counsel.

OPENING STATEMENT OF HON. HENRY M. JACKSON, A U.S. SENATOR FROM THE STATE OF WASHINGTON

The CHAIRMAN. The committee will come to order.

The hearing today begins the committee's consideration of the President's decision on an Alaska natural gas transportation system, which was transmitted to Congress on Thursday, September 22.

We are pleased to have Senator Stevens join us today to represent the interests of the great State of Alaska. Welcome, Senator.

Under the provisions of the Alaska Natural Gas Transportation Act of 1976, Congress must enact a joint resolution approving the President's decision "within 60 calendar days of continuous session" after it is submitted in order for the decision to become effective.

In enacting the 1976 act, Congress explicitly recognized that the "expeditious construction of a viable natural gas transportation system for delivery of Alaska natural gas to U.S. markets is in the national interest."

It seems clear that the procedures established by the act have already accelerated the decisionmaking process and brought us close to a final decision on this matter.

This result could not have been achieved without the magnificent cooperation of the Canadian Government and the provincial leaders involved in this issue.

While the President has selected a transportation system and the advocates of competing routes have largely withdrawn from the field, the Congress is not relieved of responsibility for examining the President's decision with the greatest care.

I will place in the record a copy of S.J. Res. 82.

[The joint resolution follows:]

95TH CONGRESS
1ST SESSION

S. J. RES. 82

IN THE SENATE OF THE UNITED STATES

SEPTEMBER 22, 1977

Mr. JACKSON introduced the following joint resolution; which was read twice and referred to the Committee on Energy and Natural Resources

JOINT RESOLUTION

To approve the Presidential decision on an Alaska natural gas transportation system

Resolved by the Senate and House of Representatives of the United States of America in Congress assembled, That the House of Representatives and Senate approve the Presidential decision on an Alaska natural gas transportation system submitted to the Congress on September 22, 1977, and find that any environmental impact statements prepared relative to such system and submitted with the President's decision are in compliance with the National Environmental Policy Act of 1969.

II

The CHAIRMAN. We must be sure that the system selected is, in fact, viable from social, economic, and political perspectives. We are delighted to welcome the new Secretary of the Department of Energy.

I believe this is your first appearance in your new capacity before this committee, to present the administration's testimony at this opening session.

Secretary Schlesinger, we are delighted to have you with us this morning.

STATEMENT OF HON. JAMES R. SCHLESINGER, SECRETARY, DEPARTMENT OF ENERGY

Secretary SCHLESINGER. Thank you, Mr. Chairman.

Mr. Chairman, I think that it may be better procedurally to place my testimony in the record and to summarize briefly. Also, Mr. Chairman, some of the questions that may be raised this morning are likely to be of a technical nature.

We would like to have the authorization of the committee to amplify on technical matters in the record and denote those amplifications of the testimony.

The CHAIRMAN. That certainly is in order, and without objection, it is so ordered.

Secretary SCHLESINGER. Mr. Chairman, the areas that should be dealt with, I think——

The CHAIRMAN. Without objection, your entire statement will go in the record.

Secretary SCHLESINGER. Mr. Chairman, let me attempt very briefly to summarize how we got to where we are in terms of the President's recommendation, which will be reviewed by this committee.

I will do this under three headings, Mr. Chairman. The first will be how we define the overland route through Canada. That, I think, is an essential element in understanding certain aspects of the agreement that may be of interest to the committee.

Second, comparing that defined overland route with the El Paso route, and third, to develop some viewpoints regarding what the implications are of this agreement for United States-Canadian relations.

Mr. Chairman, as you will recall, the first proposal for a natural gas transportation system from Alaska was the so-called arctic gas route.

That route would have crossed the Arctic Wildlife Range, come down the Mackenzie Delta and down the Mackenzie River, coming into the southern 48 States in that fashion.

The alternative route was the one proposed to run along an existing corridor, the Alcan Highway, and as a result of a decision by the Canadian National Energy Board, the arctic gas route was precluded.

And, on the Fourth of July, the NEB chose the Alcan route, with modifications. The arctic gas route thus went down because of a variety of considerations.

Most importantly, I believe, were the environmental considerations, from the standpoint of both the Berger report and the standpoint of the NEB. The Fourth of July decision of the NEB is the takeoff point for all negotiations between ourselves and the Canadians.

The chief feature of the Fourth of July decision by the NEB was to divert the original Alcan proposal through Dawson, and then to rejoin the original route at White Horse.

The purpose of that diversion was to bring the pipeline closer to the Mackenzie Delta, where it would have gone in the arctic gas proposal, and consequently provide inducements to Canadian producers more vigorously to explore the Mackenzie Delta area.

The problem with the so-called Dawson diversion was that it would have added about $650 million to the initial capital costs of the project, something we sought to avoid. As I will state in a moment, we managed to negotiate back to the original Alcan route, along the Alcan Highway.

The second feature was a $200 million socio-economic impact assistance payment, which we will also manage to avoid in terms of its imposing a charge on the American consumer.

The total effect of our negotiations with the Canadians was to reduce the projected 20-year average cost of service to the American consumer from $1.13–$1.12—in constant 1975 dollars—under the NEB decision, to $1.04.

Thus, from the original authorizing decision on the Fourth of July, we have improved that decision in a number of significant ways.

At the same time, we have improved the decision from the standpoint of Canadian consumers, and it is a display of how the two countries, working together, can improve the overall benefits from the standpoint of the citizens of both countries, demonstrating, I think, that what is to the advantage of one country is not necessarily to the disadvantage of the other country.

Generally speaking, Mr. Chairman, we have agreed with the Canadians that if the Dempster Lateral is built to the Canadian Mackenzie Delta, that the American consumer will underwrite some share of the cost of the so-called Dawson Spur, from White Horse to Dawson.

That is far more economical from our standpoint than is the Dawson diversion. Its capital costs are lower. If, indeed, the Dempster Lateral is not constructed, we avoid costs entirely.

If the Dempster Lateral is constructed, the Dawson Spur can be constructed in a timely manner, so we avoid capital charges for 3, 4, and 5 years, depending on how long it might be before the Dempster Lateral is built.

In addition, the United States and Canada agreed to install a high capacity line south of White Horse. That is a 1,680 per square inch line, possibly, or a 54-inch line that will accommodate the much larger volumes of gas that would be associated with the bringing in of the delta gas.

So we have altered the nature of the route approved by the NEB on the Fourth of July, and the alteration in the route and the characteristics of the pipe along the route are such as to benefit consumers in both countries.

As a result of those negotiations with the Canadians, we have brought the average cost of service down to $1.04. I underscore that, because the second point that we should raise is the question of the comparison between the El Paso proposal and the Alcan proposal.

Mr. Chairman, as you know, El Paso has quite graciously withdrawn from this competition, as a result of the President's decision.

El Paso has felt that further pursuing of its proposal at this time would be disruptive to the national interest. I want to review for the committee very briefly why it was that El Paso was not chosen.

The El Paso line would carry gas to Gravina Point, where it would be liquified and then moved in liquified natural gas tankers to a point in the vicinity of Los Angeles, at Point Concepcion.

That is to be compared with the Alcan project. The President's decision was based primarily on the differences in cost of services.

Our estimate is that the cost of service for the Alcan proposal would be $1.04 in 1975 dollars, as compared to $1.21 for the El Paso proposal—a difference of some 15 percent.

Over the course of the years, the cost of service difference to the American consumer would amount to something on the order of $6 billion. Of course, in any 1 year, there is a significant difference in the cost of service on average, a difference of some $300 million per year in cost of service.

In addition to that, there is a much higher rate of efficiency associated with Alcan, as opposed to El Paso. This is without taking into account the consumption of bunker fuel from Gravina Point to California, which would reduce the efficiencies of El Paso somewhat more, down to about 87 percent.

The consequence of these judgments is that we save something on the order of six-tenths of 1 trillion cubic feet almost 1 year's movement of gas from Alaska to the lower 48 States.

There is a substantial difference, also, in terms of the national economic benefit as between El Paso and Alcan, even with all of the adjustments.

There is something on the order of $1.1 billion or $1.2 billion—constant 1975 dollars—difference between the two proposals. So I think the judgment was clearcut and I think that even the El Paso proponents have conceded that, were it not for the existence of international frontiers, there is no question but that an overland route should be pursued.

We have negotiated at considerable length with the Canadians, and let me close on that note, Mr. Chairman. The third point involves our relations with the Canadians, that this agreement coming at this time is of great benefit to a furtherance of United States-Canadian relationships.

Those relationships have varied over the years. We can go back to the period of the DEW Line, of the foundation of Norad; during the Vietnam War, our relations with the Canadians became somewhat tattered.

I think we are launching ourselves to a new era of good relationships with the Canadians. This proposal contributes to it, so in that broader, political sense, it is desirable, in addition to the narrower economic sense.

I think we can all understand that cooperation between our two countries has great advantage; that it provides mutual benefits that can be shared.

This is not a zero sum gain. The construction of this joint pipeline will take place at lower cost and provide higher benefits for both countries.

We could have proceeded independently. We could have gone on the El Paso route and the Canadians could have gone on their Maple Leaf route. The consequence would have been higher construction costs, higher cost of service in both countries.

Through cooperation there are mutual benefits that I think have been fairly shared. We have established a new political climate with the Canadians, which will be beneficial in the largest sense, but will also be beneficial, Mr. Chairman, I believe, in terms of our future energy relationships with Canada.

Thank you very much.

[The prepared statement of Secretary Schlesinger follows:]

STATEMENT OF HON. JAMES R. SCHLESINGER, SECRETARY, DEPARTMENT OF ENERGY

Mr. Chairman, I am honored to address this committee in support of the President's Decision and Report on an Alaska Natural Gas Transportation System, which was transmitted to the Congress Thursday, September 22, 1977. The submission on this decision and report represents the culmination of a unique study and review process, established by the Congress in the Alaska Natural Gas Transportation Act of 1976, to select a superior and cost-effiicent transportation system.

The discovery of 24 trillion cubic feet of natural gas in Prudhoe Bay resulted in submissions by three applicants to the Federal Power Commission for a certificate to construct a pipeline to move Alaskan gas to the Lower 48 States. In March 1974, Arctic Gas Pipeline Co. filed an application before the FPC and the National Energy Board of Canada to construct a pipeline across the North Slope through the Arctic National Wildlife Range.

In July of this year, the Canadian NEB rejected the Arctic Gas proposal for environmental and socioeconomic reasons. In September 1974, El Paso Alaska Co. filed an application to transport Alaskan gas by a pipeline adjacent to the Alyeska oil pipeline to the Gulf of Alaska, liquify it and then ship it to California by LNG tanker.

Finally, on July 9, 1976, Alcan Pipeline Company and Northwest Pipeline Company (Alcan) filed the third application with the FPC for a certificate to transport Alaskan gas. The Alcan plan, as modified in March 1977, calls for a pipeline following existing utility corridors from Prudhoe Bay through Canada to U.S. markets.

Under the Trans-Alaska Oil Pipeline Act of 1973, Congress authorized the President to explore the possibility of a gas pipeline across Canada with the Canadian Government. As a result of those discussions, a transit pipeline treaty of general applicability to all energy transportation systems shared by both countries was developed and finally signed on January 28, 1977.

Congress, recognizing the shortages of natural gas, and the potential for delay inhert in the normal regulatory approach to a project of this magnitude, enacted the Alaskan Natural Gas Transportation Act of 1976. The study and decision process established by the act has called on the collective expertise of many Federal and State agencies. In May 1977, after months of hearings, which developed over 50,000 pages of testimony and exhibits, the Federal Power Commission (FPC) issued a one-volume report, "Recommendation to the President," urging the designation of an overland pipeline system through Canada. After the FPC's report, pursuant to statute, 10 Federal interagency task forces were organized to report by July 1, 1977, on the various issues underlying the selection of a transportation system. Thousands of pages of analysis from these interagency task forces, as well as private individuals, were submitted to the White House.

That voluminous record now supports the conclusion in the decision and report that the Alcan pipeline system will deliver more natural gas at less cost to a greater number of Americans than any other transportation system. The decision and report explains in some detail the various aspects of the natural gas transportation system designated for approval. Rather than summarize each chapter of the report, I shall briefly discuss the major advantages of the Alcan system and the agreement negotiated with the Canadians to protect those advantages.

The recent agreement on principles between the United States and Canada ensures the basic superiority of the Alcan system proposal over the El Paso Alaska Cop. proposal to liquefy Alaska gas and ship it to the west coast. The cost of service advantage of the Alcan system is perhaps the principal factor in determining the value of the project to U.S. consumers. Over a 20-year period under the expected cost overrun case, the Alcan system will deliver Alaska gas to U.S. consumers at a significantly lower cost of service than El Paso—estimated to be $1.04 per MMBtu for Alcan and $1.21 per MMBtu for El Paso. This $.17 difference represents an ultimate savings of $6 billion for U.S. consumers over the life of the Alcan project. The proposed Alcan system will deliver Alaska gas at the lowest possible cost of service to U.S. consumers—below the cost of imported oil and substantially below the cost of other fuel alternatives.

Alcan also has a markedly higher net national economic benefit than El Paso. The calculation of the NNEB compares the present value of real resource expenditures for a project with the present value of future benefits. For expected case cost overruns of 40 percent, Alcan has an estimated NNEB of $5.57 billion, more than $1.1 billion higher than the estimated NNEB of El Paso. But even for the worst case overruns, both parties still have a positive NNEB. The analysis incorporated in the President's decision and report supports the finding that construction of an Alaska Natural Gas transportation system at the earliest possible time is in the national interest.

The fundamental difference between the El Paso and Alcan systems is that an overland pipeline system is inherently more efficient than an LNG transportation system. The liquefaction process consumes more natural gas, raising the direct cost to consumers and lowering the base over which that cost can be spread. Furthermore, El Paso has approximately 100 percent higher operating costs than Alcan. For these reasons alone, Alcan has a 16.5 cent per MMBtu advantage over El Paso.

Beyond these cost-of-service advantages, Alcan has significant technical and resource advantages over El Paso. These include:

The superiority of pipeline transportation over LNG transportation for the safest and most reliable delivery of gas, and for expansibility of capacity to deliver increased volumes from reserves other than the Prudhoe Bay pool;

The substantial advantage of pipeline facilities over LNG facilities in having a useful life of over 40 years;

The need to anticipate future shipment of natural gas from the Gulf of Alaska which may require LNG deliveries to the west coast, thus preserving LNG delivery potential on the west coast.

Furthermore, virtually all Federal agencies and private parties that compared the two projects determined that the Alcan system is environmentally superior to El Paso.

The agreement with Canada on the Alcan system guarantees the basic economic superiority of the Alcan project. The agreement on principles provides assurances on routes, taxation levels, project delays and other critical matters. This agreement, along with the transit pipeline treaty, protects the project from unfair or discriminatory charges that would otherwise threaten the savings to U.S. consumers.

Negotiations over the elements of a joint United States-Canadian system began in earnest after the July 4th decision of the Canadian National Energy Board (NEB). The NEB permitted the construction of the Alcan system through Canada only with substantial modifications that made the system considerably less attractive to the United States on economic grounds. The Canadians insisted on an expensive route diversion of the main line to Dawson City in the Yukon and a front-end $200 million impact assistance payment to the Yukon above and beyond any property tax that might be imposed.

The agreement signed with the Canadians eliminates both these conditions. First, the agreement provides that the Alcan pipeline will follow the original Alcan Highway route. This provision alone saves the U.S. consumer up to $630 million in initial construction costs, or the 6 cents in cost of service that would have been added by the route diversion. From the Canadian perspective, the route diversion was designed to bring the Alcan system within reach of their Mackenzie Delta Reserves. From the U.S. perspective, it was a costly and inefficient modification of the main line to accommodate an uncertain eventuality—construction of the Dempster line—which might never occur.

In place of the route diversion, the U.S. agreed to pay a portion of the cost for extension of the Dempster lateral from Dawson to Whitehorse—if and when the lateral is built.

This limited extension or "spur" will connect the Dempster line with the main Alcan system. A higher capacity system will then be installed south of Whitehorse, with cost of service shared on a volumetric basis, to carry both U.S. and Canadian gas.

Without some limited U.S. contribution to assist Canada in developing the Mackenzie Delta Reserves, no pipeline agreement could have been reached. However, the formula share for U.S. cost of service of the Dawson Spur is more limited than cost for a main line diversion, and this share is tied to the percent of actual cost overruns on construction of the main line. Thus, the cost-share formula creates a formidable incentive for Canada to build the main line as efficiently as possible, and decrease the overall cost of service to U.S. consumers to the maximum extent. Furthermore, These favorable concessions aside, it is in the long-run interest of U.S. consumers to assist Canada in developing these reserves.

Paragraph 6 of the agreement explains the cost-share formula for the Dawson Spur. The more efficiently the Canadians can construct the main Alcan line, and lower the cost of service to U.S. consumers, the higher the U.S. share for construction of the spur. For example, with an overrun of 25 percent in Canada, the U.S. pays 100 percent. However, the average U.S. cost of service in this case over a 20-year period will be approximately $1.00 per MMBtu (in 1975 dollars), or 4 cents less than the cost of service under the expected overrun case of 40 percent. In this latter case the United States would pay only 83⅓ percent of the Dawson Spur.

At a minimum, the United States will pay a two-thirds share, or the percentage of U.S. gas volumes in the main line, for the total cost of service of the Dawson Spur. This would also have been the U.S. cost share for the route diversion required by the NEB.

The agreement additionally imposes a ceiling on the costs to which the minimum share applies. Thus, the United States will not be liable for costs of the spur in excess of 35 percent above the filed costs, unless the Canadians can credit cost overrun savings they achieve on the main line to the Dawson Spur. The U.S. share of the Dawson Spur cost of service can never be less than the U.S. percentage of gas volumes in the line south of Whitehorse, multiplied by the actual costs of the Dawson Spur, notwithstanding the Dawson Spur ceiling and the overrun formula. However, this last condition is only relevant in the case where substantial overruns in excess of 50 percent are experienced on the entire system. Furthermore, the agreement ensures that the system installed on the Dawson Spur will be the same as that for the whole Dempster line in order to prevent loading of costs onto the Dawson Spur.

Second, the agreement on principles eliminates the requirement of a $200 million impact assistance payment, and imposes a comprehensive ceiling on taxation of the pipeline. The three western Provinces have agreed to abide by the principles of the Transit Pipeline Treaty, and have stated publicly that treatment of the Alcan line will be the same as for similar pipelines in their jurisdiction. In the Yukon Territory, where there are no similar pipelines, special ceilings were negotiated as part of the agreement on principles. The rate of property taxation is essentially the same as that for Alaska. The agreed rate will continue for 25 years or until a similar pipeline is built. It is expected that the Dempster lateral, or some other lateral to the Mackenzie Delta will be in service in 1985, 2 years after the main line is operational. At that point the treaty will apply, and the tax on the main line will be similar to the tax on the Canadian-built lateral. Otherwise, the negotiated ceilings will apply only in the extremely unlikely event that the Canadians do not develop their Mackenzie Delta reserves.

After 1988, the Yukan tax level could be adjusted to rise either with the GNP deflator or with the rate of increase of per capita revenues for the Yukon Territorial Government, from sources other than the pipeline. It might also be adjusted retroactively for the period 1983 to 1987 if the Yukon per capita tax rate or the Alaskan property tax has increased at a rate higher than the Canadian GNP deflator.

Any required impact payments needed in advance of taxes will be treated as a loan by the companies to the Government to be paid back out of future tax revenues. The United States will have no role whatever in this arrangement. The ceiling on Yukon taxes represents only a modest increase over the level of taxes included in original cost of service estimates for Alcan. This agreement is, therefore, a substantial gain for the United States over the NEB decision, and removes a potentially troublesome open-ended tax and a large additional impact payment.

Finally, the agreement commits both countries to a timetable for construction of the Alcan system. The agreement calls for main line pipelaying to begin in the Yukon by January 1, 1981. In addition, the Canadian Government has made a clear public statement that settlement of Native claims in the Yukon will neither delay the project nor increase costs.

As a result of the agreement on principles, both the United States and Canadian Governments have measurably improved their positions from the NEB decision. The modifications of the NEB decision will lower the cost of service price of Alaskan and Canadian gas for consumers in both countries. But the agreement is particularly advantageous to the United States by providing ceilings on every aspect of potential United States liability while creating new incentives for efficient construction on a portion of the project that would normally be subject to exclusive Canadian jurisdiction.

In general, the Canadians will have the greatest incentive to minimize cost of service because Canadian, as well as United States, shippers will share the Alcan cost of service on a volumetric basis. The consumers of both countries will be adversely affected if the cost of service tariff is unreasonably high.

Furthermore, although the Canadian NEB has authority over tariff matters in Canada, the tariff must ultimately be accepted by the FPC, which can refuse to certificate the project if the tariff is inappropriate.

Beyond its cost of service superiority, however, only a joint undertaking negotiated with Canada could have provided United States consumers with energy supplies from Canada in addition to Alaska gas. These potential supply advantages would almost surely have been lost in a unilateral all-United States project like El Paso's. Specifically, the Alcan system will—

Assist Canada to continue supplying gas exports under existing contracts by providing it with access to substantial Mackenzie Delta reserves;

Provide the opportunity to obtain additional gas at an early construction of portions of the southern Canadian and Lower 48 sections of Alan, with delivery of gas from Alberta—where there is temporary excess supply—in advance of the delivery of Alaska gas;

Encourage exploration for new reserves and stimulate expansion of the gas industry in Canada, which might ultimately benefit United States consumers through the enhanced potential of Canadian supplies.

Furthermore, this point United States-Canadian undertaking could result in significant cooperation with Canada on a variety of other energy issues, such as oil exchanges, pipelines and strategic reserves. Choice of the all-United States route would have resulted in sacrifice of these benefits.

Finally, this joint undertaking between the United States and Canada has implications that go beyond the supply and cost of service advantages that will be provided by this particular project to United States consumers.

Almost four years have passed since the industrialized countries were brought face to face with the energy crisis. Since that time, each has been exploring its own options for coping with the problem, with only limited attempts at cooperation. In the course of analysis and discussion during that period, the need for better international cooperation in dealing with energy problems has become increasingly evident.

The Alcan joint pipeline project is a concrete example of how cooperation between two countries in energy matters can make both better off than they would be if constrained by a timid kind of energy isolationism. The United States and Canada working together can move more volumes of energy more efficiently than either country acting by itself.

I urge the Congress to approve the President's decision and report, and authorize a project that will serve as a symbol of the benefits to be derived from enlightened recognition of mutual interest.

The CHAIRMAN. Mr. Secretary, what is the situation regarding the financing of the line?

Secretary SCHLESINGER. With regard to the financing of the line it is the agreement of both countries that the line must, indeed, be privately financed.

Both countries have agreed, and the Prime Minister has stated, and the President has stated for the United States that no public funds—the avoidance of investing public funds in the construction of this pipeline is an underlying principle of the decision in both countries.

We have received assurance from the various underwriting houses that, indeed, this line can be privately financed and we expect that it will be privately financed.

We have underscored to them that the risks of noncompletion must fall on the entrepreneurs of the line. We will not accept an all-events tariff.

We have, in addition, created certain incentives with regard to private financing, notably the variable rate of return, which we hope will hold down costs and avoid a repetition of the cost overruns associated with the Alyeska development.

The CHAIRMAN. Let me read the financing issue on page 104 of the report:

> The conclusion reached here regarding private financing without consumer noncompletion guarantees differs substantially from the position taken by most parties in the Federal Power Commission proceeding, and by representatives of El Paso in their most recent statement.
>
> These statements were made prior to significant steps that have been taken in recent weeks to reduce uncertainty and to create proper planning, control, and incentives.

What are these significant steps?

Secretary SCHLESINGER. They are listed here, Mr. Chairman, on pages 102 and 103.

The CHAIRMAN. Has there been any kind of a letter of intent from the financial houses?

Secretary SCHLESINGER. We have one of those, Mr. Chairman.

The CHAIRMAN. Indicating that there will be private financing?

Secretary SCHLESINGER. Yes, sir, we have these letters and we will submit them for the record.

[The following was subsequently supplied for the record:]

NORTHWEST PIPELINE CORP.,
Salt Lake City, Utah, August 10, 1977.

Hon. JAMES R. SCHLESINGER,
Assistant to the President,
The White House, Washington, D.C.

DEAR DR. SCHLESINGER: A meeting was held on August 2, 1977, at the request of the Department of Treasury attended by representatives of your Alaska Natural Gas Task Force and the Office of Management and Budget.

The purpose of the meeting was to discuss the impact of the National Energy Board decision on our financing plan, the sponsor guarantee approach to financing and our thinking on alternative approaches to financing which would minimize consumer risk bearing. The first two items were summarized in written form and presented to the Task Force at the meeting. In connection with the third item, I have asked Mark J. Millard, Vice Chairman of Loeb Rhoades and Co., Inc. to summarize our financial advisors' thinking for you, a copy of which is attached.

Best personal regards,

JOHN G. MCMILLIAN,
President.

Enclosure.

LOEB RHOADES,
New York, N.Y., August 10, 1977.

Memorandum to: John G. McMillian.
From: Mark J. Millard.

We were asked by the White House Task Force to consider the feasibility of private financing without a "consumer guarantee" before completion. We have concluded that such private financing is possible and we discussed certain credit support and tariff techniques to assure that natural gas consumers would not be obligated to support the project until it was completed. The following is a summary of remarks that I made to the Task Force on August 2, 1977:

Concern and doubt has been expressed about the practicality of implementing legislative and regulatory assurances in support of the financing of the Alaskan gas project. It is important to understand the background on which the demands for maximum financial assurances arose. The testimony before the Federal Power Commission of the other two applicants (preceding that of Alcan) sought to establish that, because of the size of the project, the financial risks associated with construction and operation of an Alaskan gas transportation system exceeded the financial capability of the natural gas transportation industry. In addition to the sheer size of the project, the parties were acutely aware of the history of a number of important energy projects launched in the late 1960's and 1970's which had run into regulatory and environmental delays and had ended either in abandonment or in large cost increases. An answer to these difficulties proposed by the two original applicants was a fail-safe regulatory approach labeled an "all-events" tariff and a "perfect tracking" of charges.

In substance, the new formulas were an attempt to provide for the automatic recovery of all legitimate costs and to minimize the exposure of the lenders to unpredictable developments. The obvious aim was to put to rest the worries of the prospective lenders to the new pipeline and to by-pass the veto powers of the creditors of the line's future stockholders.

We are now asked to reassess, under today's conditions, the minimum requirements for a private financing of the Alaskan gas pipeline. We submit the following as our main points:

1. The risks associated with construction and operation of an Alaskan gas system, as extensively discussed by all applicants' financial advisors, must be borne by credit-worthy parties in order to achieve a successful private financing.

2. There is sufficient credit support capacity among the primary beneficiaries of gas pipelines, excluding the consumer, to assure completion of the pipeline. This is the single most important risk to be addressed in arranging a private financing. Such beneficiaries are the gas transmission companies, gas producers, and the State of Alaska.

3. It is essential to establish mutually satisfactory and speedy procedures in three areas: first, the monitoring of engineering and environmental decisions by the appropriate government agencies for definitive approval of expenditures; second, the creation of the efficient cooperation between U.S. and Canadian officials with authority to make the final joint decisions where needed; and third, continuation and further development of a positive regulatory climate under the Department of Energy.

4. The obligations of consumers to pay certified costs of the project can be limited to a minimum bill tariff commencing when initial gas deliveries are made. I do not believe legislation obligating gas consumers to an "all-events" tariff, which provides for payment of cost prior to the completion of construction, is a necessary condition of successful private financing if sufficient overrun funds are provided.

5. By removing the consumers from the pre-completion risk, the remaining beneficiaries must increase their share of the risk, for which they will require compensation, thus increasing delivered cost of gas to the consumer.

There are certain matters requiring prompt government action which must be resolved before actual financing negotiations can commence. Three of the most important are:

1. Rolling-in the price of Alaskan gas into the overall charges of the participating gas companies.

2. A decision on the pattern of distribution of the Prudhoe Bay gas in the lower 48 states.

3. Approval of a pricing mechanism for Alaska gas whereby the non-consumer beneficiaries of Alaska gas will be induced to provide sufficient financial support to finance the line.

Possibilities for avoiding consumer support for completion of the pipeline exist in three areas. They are (1) the terms on which the equity will be invested, (2) the participation of the State of Alaska in the financing, and (3) the participation by the gas producers.

As to the form of equity financing, Alcan will be willing to propose to its prospective stockholders the following features:

1. The equity will be at risk.

2. The equity will be pre-paid and pre-spent as compared to the collection and expenditure of the proceeds of debt securities.

3. Additional equity on a pro-rate basis will be precommitted for the event of overruns.

4. The equity rate of return will be reduced if overruns occur, thus adding strong financial incentives for efficient management.

The State of Alaska has indicated that it would make available state support, presumably in a subordinated position, to the El Paso project. Alcan has been given to understand that essentially the same support would be available if it were selected. Such a financing, at an attractive interest rate, would enhance the feasibility of a private financing and reduce the overall cost of money.

The most important outside contribution to the success of a private financing could be made by the producers. It is closely related to the question of the gas price. The value of Alaskan gas at the wellhead is closely linked to the cost of transporting it to market. Other things being equal, the wellhead value changes inversely with changes in the cost of transportation. However, since the gas economy of the U.S. will remain subject to regulation, market values are not the sole criteria of price. Regulation follows other yardsticks, including the cost of production and processing, which appears to be especially high or Alaskan gas. Regulation can also recognize the economic value of a willingness of the oil companies to participate in the financing of the pipeline. There is a trade-off between regulatory recognition of such a financial contribution in a higher gas price and the advantages which the participation of the oil companies in the financing of the pipeline can bring to the consumers.

At the time of the meeting, we made in a preliminary form specific proposals on how the interplay between the gas price and the pipeline financing could be used to the advantage of all concerned parties but in the interest of the consumers as the main point of reference. Alcan believes that a further discussion of these matters could be fruitful before the government makes its decision as to the price of Prudhoe Bay gas.

Secretary SCHLESINGER. This is a memorandum addressed to John McMillian by Mr. Mark Millard of Loeb, Rhodes & Co., which discusses at considerable length the feasibility, indeed, the likelihood of private financing.

The CHAIRMAN. Are they attaching any conditions or unequivocal assurances that we are getting on the financing?

Secretary SCHLESINGER. I beg your pardon?

The CHAIRMAN. I say, do these letters that you refer to, the one from Loeb, Rhodes and maybe some others, are they unequivocal in their willingness to provide and make arrangements for the financing?

Are there questions here that involve conditions that would have to be met that are unusual, other than those conditions that are normal in any financing of a large project?

Secretary SCHLESINGER. That is a matter of judgment, Mr. Chairman. I would be inclined to say no to that question. Of course, there are always unique features in any financing. But they are unequivocal in saying that they believe that financing can be arranged.

They are unequivocal in their commitment to attempt to arrange that financing. There are certain contingent issues and they indicate that two of the contingencies, contingent issues that may be of significance, are the contributions by the producers and the State of Alaska.

Those are complex questions, and I do not know whether you wish me to go into those matters at this time.

The CHAIRMAN. No, on that point there is only one large one that I referred to. That is, will the producers pay for the gas-processing plant that I understand would be built at Prudhoe Bay and which is necessary in order to upgrade the gas before it is moved into the pipeline?

The staff informs me that the cost is around $2 billion, and that is a rather sizable item. I am trying to bring up the larger ones, not the smaller ones.

Secretary SCHLESINGER. Yes, sir. The underlying point, I think, Mr. Chairman, is that the processing of this gas is not a normal part of the transportation system.

It is not the responsibility of those who would arrange transportation. Indeed, it is the responsibility of the producers.

The figure for $2 billion I think is rather an all-encompassing figure. It includes investments that have already been or would be made in connection with the production of oil.

It is our estimate that the net additional cost for processing of gas will be something less than $1 billion. That charge, the responsibility for achieving that investment, will be on the producers, rather than on the part of the transportation company.

The CHAIRMAN. And that is very clear in the decision?

Secretary SCHLESINGER. Yes, sir.

The CHAIRMAN. So that is an item that will be borne by the producers, whatever it is, whatever they estimate?

Secretary SCHLESINGER. Yes, sir. Until such time as Federal jurisdiction is requested, there is no involvement of the Federal Government in that issue.

The responsibility rests with the State of Alaska for the regulation, as it were, of that processing facility.

The CHAIRMAN. As I understand it, it is made very clear here that the Federal Government is not involved in any manner, shape, or form, in guaranteeing the financing in connection with the building of the line.

Secretary SCHLESINGER. That is correct, sir.

The CHAIRMAN. What if the project is not completed? Are the financial houses asking for a guarantee in that contingency?

Secretary SCHLESINGER. No, they have stated that they do not expect that there would be an all-events tariff. Responsibility for noncompletion would rest with the entrepreneurs for this line.

The CHAIRMAN. To follow up on the financial side of it, I take it that you have guarantees from the Canadian Federal Government regarding the issue that always comes up in a matter of this kind regarding discriminatory taxes that might be levied by a Provincial government against the pipelines.

I ask that in light of the fact that—and correct me if I am wrong—that under Canadian law a treaty is not the supreme law of the land in Canada, as it is in the United States, since *Missouri* v. *Holland* was handed down by our court in about 1920.

Therefore, under Canadian law, the Provinces are not bound by the treaty, per se. Does the Federal Government of Canada propose to guarantee the performance of the Provinces in connection with their somewhat exclusive authority to deal with—under their constitution—with natural resources in all manner, shapes, and forms?

Secretary SCHLESINGER. Yes, sir. I think the documents on pages 81, 82, and 83, of the President's decision and report to the Congress are relevant here.

Those are statements by British Columbia, Alberta, and Saskatchewan, indicating that the governments of those Provinces expect to collaborate with the Federal Government in terms of the cooperation on the pipeline itself, and to accept the principles elaborated in the treaty.

The Government of—the Federal Government has been promised by these three Provinces that, indeed, they will enter into further commitments, which we will scrutinize carefully to insure, indeed, that the principles of the treaty are accepted by the three Provinces.

In addition to that, Mr. Chairman, as you have indicated in your question, the Federal Government of Canada would be liable for the performance of the Provinces and should, for some reason or another, if one can hypothesize, the Provinces fail to live up to their commitment in this regard, it would be the Federal Government that would be

98-069 O - 78 - 2

responsible to us, rather than the weight of such additional costs falling upon the American consumer.

The CHAIRMAN. In their covenant with us, do they guarantee the performance of the Provinces?

Secretary SCHLESINGER. The answer is yes, sir, in the agreements they guarantee.

The CHAIRMAN. They do. Now, on pages 81, 82, and 83, I note that on page 81 that the British Columbia statement, and I guess it is similar to the others, their statement is contingent upon the working out a negotiation of the Federal-Provincial agreement.

Those agreements—have they been negotiated?

Secretary SCHLESINGER. No, sir, that is what I was referring to.

The CHAIRMAN. I got diverted here for a minute on some other matters, and I am sorry.

Secretary SCHLESINGER. Making these matters effective will depend upon a Federal-Provincial agreement. We will monitor the progress toward those agreements very carefully.

I underscore what British Columbia has said, at as early a date as possible it is the expectation that these Provincial-Federal agreements will be forthcoming very shortly.

The CHAIRMAN. On the bottom of page 81, could we have that telegram: "Such agreements should guarantee that the British Columbia position expressed in its telegram of August 31 is protected"? Can we have that?

Secretary SCHLESINGER. Yes, sir; we will get that for you.

The CHAIRMAN. We do want that for the record.

[The following was subsequently supplied for the record:]

The United States Government has been informed that the contents of the August 31, 1977, telegram referred to in the statement of the Government of British Columbia is considered a privileged matter between the Canadian Federal Government and the Government of the Province of British Columbia. Secretary Schlesinger was not aware of the privileged nature of this communication at the time of his testimony before the Senate Energy and Natural Resources Committee.

The statement attached has been received from the Government of Canada with regard to the August 31, 1977, telegram and Senator Jackson's request for insertion of that telegram into the record.

Attachment.

CANADIAN EMBASSY,
AMBASSADE DU CANADA,
Washington, D.C., October 11, 1977.

Mr. GERALD A. ROSEN,
Director of Fuels and Energy,
Department of State,
Washington, D.C.

DEAR MR. ROSEN: We have noted that on page 19 of the transcript of the hearings on the President's Decision and Report on an Alaskan natural gas transportation system of the United States Senate Committee on Energy and Natural Resources dated September 26, 1977 that reference was made to a August 31 telegram between the Government of the Province of British Columbia and the Government of Canada.

We think it appropriate to point out that the Government of Canada and the Government of British Columbia consider that telegram to be a privileged document which will not be made public, that deals with matters solely of concern to those governments.

We trust that this will clarify the status of the document to which reference was made.

Yours sincerely,

N. R. CHAPPELL, *Minister Counsellor.*

The CHAIRMAN. My concern, of course, is to make sure that the Canadian Government—the Federal Government—is in a position to enforce within Canada, within the Provincial structure—no question about the Federal structure—the provisions of this agreement.

I would raise the question about whether or not a subsequent or a new government could come along under Canadian law and repudiate, rescind, modify, or nullify the agreement that would be negotiated or will be negotiate between Ottawa and the Provincial governments?

Secretary SCHLESINGER. Mr. Chairman, I hesitate to advise you on legal matters, since you are a lawyer——

The CHAIRMAN. I am in no man's land here. No one seems to know what the Canadian law is. We know a little bit——

Secretary SCHLESINGER. Such an action rescinding those agreements would be contrary to international law.

The CHAIRMAN. You know this question actually was raised in connection with the Colombia River Treaty. The provincial leader, Mr. Barrett, indicated that the previous agreement was unfair and even though his predecessor, Premier Bennett, had entered into an agreement with our Government, separate and apart and in addition the Federal Government had guaranteed the performance of British Columbia. He raised the question seriously that the treaty, could be nullified, because under Canadian law, in areas of natural resources the Provincial governments have the authority, as expressed in the Canadian Constitution.

The reason I am asking all these questions in this area is that I want to be sure to make a record here that will indicate that the Provincial governments are, indeed, bound.

It is the Provincial governments, under Canadian law, that have the authority. Anything that Ottawa does is not binding on them, unless there is a mechanism by which the Provincial governments can be legally bound under Canadian law.

I think we have to take judicial notice of the fact that Canadian law is different from ours.

Secretary SCHLESINGER. Yes, sir, we are, I think, however, doubly protected, in that there will be the agreement between the Provinces and Federal Government which will be a contract.

And it would seem to me, a contract that can be violated only at penalty by the Provinces. In addition, the Federal Government has guaranteed the behavior of the Provinces, so that liability for nonperformance would fall on the Federal Government of Canada, rather than upon the United States.

The CHAIRMAN. Now the agreement with Canada recognizes that legislation will be required, as I understand it, to implement the agreement.

I wonder if you can indicate to us what legislation will be required, both Provincial and Federal, if that is the case.

Secretary SCHLESINGER. The Federal legislation that will be required will be to adjust the NEB decision of the Fourth of July.

As you will recall, Mr. Chairman, there was legislative enactment to adjust that decision, and the NEB decision included a description of a route that went through Dawson, and we have now gone back to the Alcan, and so legislation in the first part——

The CHAIRMAN. In other words, the NEB decision is being modified by this agreement which comes from Parliament?

Secretary SCHLESINGER. That will require legislation to modify the decision of the NEB, which is an independent regulatory body.

The CHAIRMAN. At the Federal level. What about at the Provincial level in connection with the negotiations that will take place between Ottawa and the Provincial governments?

Secretary SCHLESINGER. The agreements will suffice in the case of the Provinces. As you pointed out a moment ago, Mr. Chairman, we expect a much more detailed agreement to come into existence between the Federal Government and these three Provinces shortly.

But they should be sufficient for the Provinces. In addition, all of the Commissions of Inquiry in Canada have proposed strong monitoring authority for the pipeline in Canada, and it will require Canadian legislation to insure that strong monitoring authority for pipeline constructon that will be part of the package.

The CHAIRMAN. Mr. Secretary, I do not want to monopolize the time here, but I do have some questions regarding the gas that will be allocated to California and the Pacific Northwest.

I think we can handle them by some interrogatories that I can submit and we can have responses from you later on.

[The interrogatories and responses follow:]

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C., October 3, 1977.

Hon. JAMES R. SCHLESINGER,
Secretary, Department of Energy,
Washington, D.C.

DEAR MR. SECRETARY: Subsequent to the Energy and Natural Resources Committee hearing on September 26 on the President's decision regarding an Alaskan natural gas transportation system, I developed the following questions to be answered for the record:

(*a*) What assurances can you give that the current contracts for delivery of Canadian natural gas to the Pacific Northwest will not be terminated prematurely as a result of early delivery of Alberta gas to the Midwest?

(*b*) What assurances can you give that early delivery of natural gas from Alberta will not subsequently be recouped from the total throughput of Alaska natural gas rather than from that share of the Alaskan gas that is dedicated to those companies receiving such early deliveries?

(*c*) I note on page 231 of the President's Decision and Report that the 4 states of the Pacific Northwest will get 22 MMCFD and the balance of 637 MMCFD will go to California. Does this appear to you to be a fair division of the Western Leg allocation in your judgment, particularly since the Pacific Northwest is so heavily dependent upon Canadian gas import contracts which will expire in 1989?

I would appreciate it if you could provide the Committee with a complete, written response to these questions at the earliest practicable date.

Sincerely yours,

HENRY M. JACKSON, *Chairman.*

ANSWERS FROM SECRETARY SCHLESINGER

The first two questions relate to the general issue of whether early deliveries from Canada would prejudice future rights of any person or company. It will be the policy of the Department of Energy that early deliveries of natural gas from Canada be allowed only to the extent that the particular purchaser holds future rights to equivalent volumes of Canadian or Alaska gas (or other supply) that could be used specifically to pay back to Canada the amount of the early delivered volumes, if payback is required. No person, wherever located, will be deprived of rights to future delivery of Canadian or Alaska gas, unless such person consents thereto.

The third question relates to the statement on page 231 of the President's Decision and Report that Pacific Gas Transmission (PGT) intends to deliver only 22 mmcfd of up to 659 mmcfd to the Pacific Northwest. The 22 mmcfd amount is from the plan provided by PGT. It does not represent an Administration proposal. The final determination regarding the distribution of Alaska gas must await the execution of actual gas sales contracts. The Federal Energy Regulatory Commission will review all such contracts to assure that they are consistent with the public interest. Among the public interest considerations specified the Decision and Report at page 220 is whether any region is ". . . arbitrarily and unequitably deprived of its share of Alaska gas."

Secretary SCHLESINGER. Very briefly, I have noticed a letter, Mr. Chairman, from you and Senator Magnuson on this particular point, referring to the 22 million cubic feet per day.

That is referred to, of course, in the President's decision, but that represents the total contracts that have been entered into at this point.

We are judging only on the basis of contracts that are the plans of the companies. That in no way constitutes a limit on the amount of gas that might go into the Northwest, but that represents kind of a running scorecard of where the companies stand at the moment.

The CHAIRMAN. We are worried about a pullback of the Alberta gas later on, which, of course, could cut our supply in the Pacific Northwest.

I will prepare specific questions so that we can go over that problem and try to get it resolved. One final question, in connection with the authorization of the Alaska pipeline.

I put in an amendment which provided for minority participation in the pipeline construction. I think that has worked out fairly well.

We wrote that into the statute. We are in a little bit different situation here, and I think it is important that before we take final action that we have an understanding, at least as it pertains to the American side, that is, from Prudhoe Bay to the Canadian line. We cannot and should not dictate to Canada—but I hope they would follow a similar policy, because they do have a number of minorities in Canada, namely, natives that would be involved in this.

But I wonder if you have any comment on that?

Secretary SCHLESINGER. Yes, sir. We have, as part of the President's decision, on page 31, terms and conditions for the applicant, a provision regarding minority business enterprise participation which follows the legislature language.

The CHAIRMAN. All right, sir. Senator Stevens.

Senator STEVENS. Thank you, Mr. Chairman, and I want to thank you again for your normal courtesy in allowing me to return to the committee for matters that pertain to Alaska.

The CHAIRMAN. We are glad to welcome you back.

Senator STEVENS. Sometimes I wish I never left. Secretary Schlesinger, tomorrow I will be stating as a witness my personal position on the President's recommendations, so I am not going to go into any of that today.

But I do want to get to some questions concerning the decision and the statements you have made. With regard to the gas-conditioning plant, it is my understanding that it was the position taken by all of the producers that the costs attributable to the conditioning of gas to meet the quality requirements of the pipeline applicants is not a production function, and that it is normal gasfield practice for the purchasers of the gas to pay for the cost of the conditioning and treatment of the gas in order to meet pipeline specifications.

Are you saying that it is the position of the administration that the costs attributable to gas conditioning on the North Slope must be considered to be prewellhead costs?

Secretary SCHLESINGER. That is the question that, in part, will be left to the Federal Energy Regulatory Commission to divide those costs that should be prewellhead from those costs that will be postwellhead.

That is indicated, I think, in the decision. We would expect that some cost of processing would be borne by the producers from the wellhead price and some might not. And that the Federal Power Commission or its successor should decide on such matters.

Senator STEVENS. If the costs are attributable to the conditioning, must come out of the wellhead price, and I understand that the President's decision indicates that that is about 30 cents per 1,000 cubic feet, our State officials inform me that it is somewhere between 75 cents and 97 cents million cubic feet, what will that do to the financeability of this project if the wellhead price must include this very large gas-conditioning cost?

Secretary SCHLESINGER. I would think it would not affect the financeability of the transportation project. It would affect the returns of the producers.

Or, if this is not borne from the wellhead price, it would affect the cost of the gas to the consumers in the lower 48 States, but this would be independent of the cost to the transportation system.

Senator STEVENS. Is there to be any particular legislation submitted by the administration to change the normal gasfield practice and the normal FPC past practice, so far as gas-conditioning costs are concerned with regard to this pipeline?

Secretary SCHLESINGER. No, sir, there is no such legislation intended. The decisions would be by the FPC or its successor, the FERC, presumably in relation to past practice.

Senator STEVENS. I told the chairman the other day, when we create a czar, no matter how benevolent he might be, we should expect him to act like a czar.

Let me ask you the question: As I recall, the legislation gives you the authority to submit to the regulatory agency changes in policy for their consideration. Are you going to submit to the regulatory agency, when it becomes effective October 1, a change in past FPC policies, insofar as gas-conditioning costs are concerned as it affects this gas deposit on the North Slope?

Secretary SCHLESINGER. I cannot give a categorical answer to that, Mr. Stevens. It is my understanding that the situation in Alaska is unique, their processing costs are quite different from the relatively trivial processing costs that normally occur in the lower 48 States.

Therefore, since circumstances in Alaska are relatively unique, it is hard to go on the basis of prior precedent. However, at this time we have no intention of providing such a prescription as you describe.

Those might be the duties carried out by a czar. But since I am no longer a czar, I shall no longer carry out those duties.

Senator STEVENS. You are not one yet, anyway. A benevolent one, albeit, I understand, I hope. Let me go to this agreement. When the pipeline treaty was before the Foreign Relations Committee and on the floor of the Senate, we had rather complete exchanges as to what would or would not be considered as requiring a protocol to that treaty that we previously ratified.

That treaty does not apply to any particular pipeline. This agreement does apply to a particular pipeline. Is it my understanding that the President's decision, as expressed in this report that we have got before us, is that there is nothing in the agreement with Canada that will require the submission of a protocol with regard to this particular pipeline?

Secretary SCHLESINGER. Your understanding is correct; yes, sir.

Senator STEVENS. Notwithstanding the commitments made to us at that time.

Secretary SCHLESINGER. The legislation in the Alaska Natural Gas Transportation Act envisioned what is happening at this time.

It envisioned that the President would make a recommendation. These negotiations that we have carried on are negotiations to firm up one of the options which the President chose from.

Consequently, this is designed in accordance with that legislation, the recommendation is made to the Congress, the Congress, in accordance with that legislation, votes it up or down.

Senator STEVENS. It is my understanding that the agreement indicates that the Federal Government in Canada will make the Provincial-Federal Government agreements with Alberta, British Columbia, and Saskatchewan, and you have relied upon an exchange of letters which have not yet been completed; is that correct?

Secretary SCHLESINGER. The letters refer to the Yukon taxation and the way in which that Yukon taxation should be interpreted.

While they have not been completed, Mr. Stevens, they are not directly relevant to this particular point.

Senator STEVENS. I am particularly concerned with the British Columbia statement on page 81; is that, in fact, the British Columbia statement? Or is that your summary or the administration's summary of the British Columbia position?

Secretary SCHLESINGER. That is a statement by British Columbia.

Senator STEVENS. With regard to that, and keeping in mind the history of the dealing on the Columbia River Treaty, which the chairman and I and others here recall too well, could you tell the committee: Does the agreement that you have with Canada and the understanding that they will negotiate with the Provinces and, specifically, British Columbia govern in any way the charges that British Columbia may make for the use of Provincial land as a right-of-way, as an owner of the land?

Secretary SCHLESINGER. Yes, sir.

Senator STEVENS. In what way?

Secretary SCHLESINGER. The Federal Government, as I understand it, has the right of eminent domain for such rights-of-way through the Provinces.

Senator STEVENS. It is my memory that what got us into difficulty with our neighbor in Canada over the Columbia River Treaty was the fact that British Columbia owned the public lands in the Province and refused to consent to the area that would be flooded until there was an amendment to the agreement that brought about the construction of the Peace River Dam at the cost of U.S. consumers.

At that time the position was taken that the Government had no way—the Federal Government had no way to acquire that land from British Columbia. Are you saying there is existing authority in Canada for the Federal Government to acquire British Columbia's land against its will and establish a right-of-way charge that is not discriminatory against a U.S. pipeline going through British Columbia?

Secretary SCHLESINGER. I believe that that is the case. But in addition, Mr. Stevens, the agreement states that all charges for such permits, licenses, certificates, rights-of-way, leases, and other authorizations, will be just and reasonable and apply to the pipeline in the same nondiscriminatory manner as to any other similar pipeline.

That is, once again, a pledge of nondiscrimination. The Canadian Government has indicated its responsibility in this matter, so the additional burdens, should they materialize, would not fall on the American consumer.

Senator STEVENS. During the course of the negotiations I transmitted to your staff some of the statements we had heard in Alaska, concerning the charges that certain public officials in British Columbia and former public officials in British Columbia should be assessed against the right-of-way, because of the ownership of the land and not as a governmental action.

Were those statements checked out at all during the negotiations?

Secretary SCHLESINGER. Yes, sir. We went through them very carefully, and we thank you for calling them to our attention.

Your calling those statements to our attention helped in the process of deliberation to nail down certain points that might or might not have been attended to.

Senator STEVENS. Isn't the key question: Have you nailed down British Columbia? Can we rely on the fact that British Columbia will not hold up this pipeline, as it did hold up the Columbia River project?

Secretary SCHLESINGER. I think the answer to that is yes, but we have prepared a legal memorandum for the committee on this issue regarding the relative rights and responsibilities of the Canadian Government and the Provincial government in such matters under Canadian law, and we will have that memorandum for the inspection of the committee.

[The following was subsequently supplied for the record:]

Statements by public figures in British Columbia regarding possible intentions with respect to a trans-Canada pipeline project for delivery of Alaska gas came up in the negotiations between Canada and the United States regarding such a project. Although all manner of possible discriminatory charges are intended to be covered by the Transit Pipeline Treaty, paragraph 2(b) of the Agreement on Principles applicable to a trans-Canada project (see page 48 of the President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System") was worked out to explicitly preclude any unusual fees which any provincial government, or any other taxing authority, might be tempted to impose.

In the course of those discussions, a question was raised as to how the Canadian Federal Government might enforce such a provision. The response to that question was that adequate condemnation power existed with the National Energy Board's (NEB's) eminent domain authority to allow the NEB to acquire rights-of-way on reasonable terms. Any other charges would have to be in accordance with the non-discrimination provisions of the Treaty. The memo mentioned by Secretary Schlesinger and attached was prepared by the U.S. Embassy in Ottawa to elaborate on the Federal Government's eminent domain authority. As indicated in the memo, it was prepared based on discussions with and research by the NEB's Chief Counsel. The formal statement referred to in the last paragraph was deemed not necessary.

The Columbia River Treaty is not a good precedent for considering the respective authorities of the Canadian Federal and Provincial Governments with respect to the pipeline project. The Columbia River Treaty was an undertaking directly affecting only a single Province, British Columbia. It involved the export of irreplacable natural resources to the United States, a sensitive matter for both Provincial and national governments in Canada. The water rights allocated under the Treaty belonged to the Province, and the Province's active participation in the construction of major dams in Canada was required. In short, the Province of British Columbia had a unique degree of political and economic interest in the system for the joint development of the Columbia River.

In contrast, the pipeline involves considerations of primarily national, rather than provincial, concern. It is an inter-provincial undertaking clearly within the competence of the Government of Canada. Although the line must pass through the Province of British Columbia, the Province will not be the agent for its construction. Moreover, unlike the Columbia River case, the pipeline does not involve the selling of provincial resources to the United States. Accordingly, the experience of the Columbia River Treaty need not be a precedent for the construction of the pipeline in Canada.

In the Columbia River matter, there was never a specific challenge to the authority of either Federal or Provincial Governments. In that instance, the uniqueness of British Columbia's interest prevented the Federal Government from overriding that interest. As regards the pipeline project, there can be no question of the inter-provincial character of the undertaking and, consequently, the clear authority of the Federal Government. It is clear that the Agreement on Principles with respect to this project, in combination with the generalized protection afforded by the Transit Pipeline Treaty, offers adequate assurances of responsible treatment by all of the public authorities whose jurisdictions are encountered by the project.

Attachment.

EMBASSY OF THE UNITED STATES OF AMERICA,
August 31, 1977.

Memorandum for: DOE-Mr. Goldman, State-Mr. Trimble.

CAN A PROVINCE OF CANADA INTERFERE WITH CONSTRUCTION OF A FEDERALLY APPROVED PIPELINE BY WITHHOLDING EMINENT DOMAIN, OR IN ANY OTHER WAY?

1. The answer is that there is a high probability that any such attempt would be disallowed by Canadian courts.

2. The National Energy Board Act provides for access by pipeline companies—

To privately owned land under paragraph 62(1)a;

To the Crown Lands of both provinces and Federal Government under paragraph 66 (1) and (2), provided the Governor in Council (Canadian Federal Government) so decides;

To Indian Lands under paragraph 67 (1) and (2), provided the Governor in Council so decides.

The NEB Act also provides for the use of private lands without consent of the owner, including through expropriation in paragraph 73 through 75.

3. There are two reasons for believing the courts would uphold the Federal Government in the exercise of these authorities the Constitution, and previous court cases.

Under Section 92(10a) and 91(29) of the British North American Act (BNA Act) the Federal Government has exclusive authority to regulate "works and undertakings connecting the Province with any other or others of the Provinces or exterior beyond the Limits of the Province."

Application of this provision has been upheld both considering the construction and the operation of interprovincial undertakings. In *Corporation of the City of Toronto* v. *Bell Telephone Company of Canada* (1925 Appeal Case page 52), the court enabled Bell to proceed with telephone installation in the streets of Toronto pursuant to Federal legislation, in spite of laws passed by the City Corporation. In *Commission du Salaire Minimum* v. *the Bell Telephone Company of Canada* (1966 SCR 767) the court found that "All matters which are a vital part of the operation of an interprovincial undertaking as a going concern are matters which are subject to the exclusive legislative control of the Federal Parliament within Section 91(29) [of the BNA Act]." Finally, the authority of the Federal Government to legislate for an interprovincial undertaking in all of the Provinces through which it passes was upheld in *Canadian Pacific Railway* v. *The Parish of Notre Dame du Bons Succours* (1889 Appeal Cases page 367).

4. We should ask for the above (which is based on research by NEB Chief Counsel Soloway) to be confirmed to us in a formal statement by a competent Canadian authority. However, I think we have enough to go ahead and eliminate eminent domain and other impediments in construction and operation as a significant issue.

THOMAS OSTROM ENDERS.

Senator STEVENS. Thank you. I will wait, then, to ask any further questions about that as far as I am concerned. Let me turn to the statement on page 115 of your report, where you indicate—or the President's report indicates that tradition in equity suggests that the parties which benefit directly from Alcan pipeline should participate in financing their share of the burden of these risks.

It is my understanding that the recommendation is that the State of Alaska should consider extending some offer of participation guaranteeing this project, as it did the El Paso line.

I am sure you know that the Governor of Alaska 1 week before the President's decision clarified the statement that had been made by the Alcan proponents with regard to the State's participation.

And, further, that the State's participation had been limited to the El Paso line. I have no intention of discussing the El Paso line today. They have withdrawn.

But with regard to the State's position, have you ascertained the Federal Government's return from taxes on the development of this project, its right-of-way return, and the benefits to the Federal Government, per se?

Secretary SCHLESINGER. No, sir; we will prepare such a statement for the record.

[The following was subsequently supplied for the record:]

The payment most directly attributable to the Alcan project that the Federal Government will receive will be the right-of-way fees for crossing Federal lands. In Alaska the fees will be approximately $70,000 per year or $1.4 million over the first 20 years of the project. No right-of-way evaluation has yet been made for the lower–48 States, but the mileage of Federal land right-of-way will be less than half that in Alaska.

The project also will generate substantial Federal income taxes. However, it is not possible to attribute the total amount of such taxes to direct Federal Government benefits derived from the Alcan project. The taxes will be paid because of the productive investment of capital. If the Alcan project is not constructed, it is probable than an equivalent amount of capital would be invested in other projects that should be expected to be equally as productive, and therefore should generate essentially the same level of income taxes.

Nevertheless, an estimate of Alcan's total Federal income taxes is included for the record. In the expected cost overrun case, the project would generate in the first 20 years an average of about $188 million per year in Federal income taxes, and a total of $3.76 billion.

Additionally, certain items purchased for the project will be subject to Federal excise taxes. A determination of the amount of such taxes is not possible at this time, but such taxes are subject to the same difficulty in attribution as income taxes.

Senator STEVENS. You seem to come to the conclusion that my State, because it has a royalty gas interest, should participate in the construction of the pipeline that it did not support in a foreign country that has extremely doubtful financial capability, as far as we are concerned, in terms of risk, when the Federal Government itself should not participate in any guarantee of the risk.

Can you explain to me why a State with 450,000 people should be placed in the position that the Federal Government is unwilling to take?

Secretary SCHLESINGER. Only on the basis, I think, Senator, of past interest in such projects. As you have indicated, the State was prepared and had indicated willingness to underwrite partly the El Paso line.

With the waning of the El Paso alternative, this is, from Alaska's point of view, the only pipeline they have. I think there may be some interest in seeing that it is successfully brought to a conclusion.

Senator STEVENS. You understand, of course, that the Alaskan objectives are not totally met by this pipeline, and I will make my statement tomorrow concerning that.

But as a practical matter, what it means is that somehow or other we must find some way of getting our royalty gas to Tidewater. This will not take our royalty gas to Tidewater.

It will not take our royalty gas to major markets in the south-central portion of Alaska. So if the State of Alaska is to commit its funds to anything to meet its internal purposes, it seems that it would commit its funds to guarantee a line to be built to hook up the Prudhoe Bay reserves with the Swanson River Unit reserves.

The point of my questioning is the financing of the Alcan project, so far as your advisers are concerned, contingent upon the State's participation to the extent of the $900 million guarantee.

Secretary SCHLESINGER. I think "contingent" is far too strong a word. I think that such financial involvement would be helpful to the project, but I don't know that the project is contingent upon it. I would doubt it.

Senator STEVENS. Again, in not wishing to be too obstreperous, but since you are soon to be in the position of being the head of the Department of Energy, and will have substantial authority over energy considerations, is it to be the policy of your Department "to convince"—I put that in quotes—my State that it should participate in the financing of this project?

Secretary SCHLESINGER. I think that we will use our poor powers of persuasion to help persuade, Senator, if we can.

But to convince is, perhaps, too strong a verb to employ.

Senator STEVENS. You are familiar, I assume, with the fact that Governor Brown recently met with our Governor Hammond?

Secretary SCHLESINGER. We took notice of that fact.

Senator STEVENS. Governor Brown's effort was to try to convince the State of Alaska that it should commit its royalty gas to California to be sure that California would have the gas for the western leg.

Our Governor notified the Governor of California that that was not possible. Has the financing of this project been ascertained from the point of view of its conveying seven-eighths of the gas from Prudhoe Bay and not eight-eighths?

We have the right to take the gas as it is produced and use it in our State. It is a State right to take either gas or the value of the gas.

We have a considerable number of communities in our State that are paying the highest costs for energy, I think, in the world. Has the financing of this project been checked out on the basis that we would use our gas in our State and only seven-eighths of it would be transported to the Alcan line?

Secretary SCHLESINGER. No, sir, we have checked the project out in terms of eight-eighths. We should have to review the question for seven-eighths.

Senator STEVENS. Might I respectfully suggest that you do so? And if the chairman would permit me to do so, I would like to see such an analysis, because I think the committee and the Congress ought to know.

For instance, in this agreement with Canada, and I congratulate you and the people who negotiated for Canada in doing so.

You have assured that gas to northern Canadian communities would be supplied from the Prudhoe Bay deposit as an obligation of the Alcan system. I find no similar guarantee, though, that the Alcan system must meet the needs of the small Alaskan communities through which this line goes.

And there is a considerable cost, as I understand it, in a transportation system like this, for the takeoffs for such purpose.

Are we to assume that we would have the same support for service for Alaskan communities in rural Alaska that Canada has received for rural Canada?

Secretary SCHLESINGER. I believe that's the intent. Quite obviously, such matters were not questions for international negotiation.

We had to deal with the Canadian problem in the international negotiations, but the provision of such gas for Alaskan communities along the route is not a matter to be included in the agreement.

[The following was subsequently supplied for the record:]

If the Alaska royalty gas is withdrawn from the Alcan system for use in Alaska, the unit cost of service will increase for the volumes delivered to the lower-48 States. However the amount of increase would not significantly affect the long-term marketability of the gas or feasibility of the project.

The 20-year average cost of service in 1975 dollars if the Alaska royalty gas is transported the entire distance to the lower-48 is estimated at $1.04 per MMBtu, assuming the system transports 1.2 billion cubic feet per day (bcfd) of Canadian gas as well as 2.4 bcfd of Alaskan. However, if the royalty gas is withdrawn from the Alcan system at Fairbanks, for example, the 20-year average cost of service to the lower-48 States would increase to between $1.11 and $1.12 per MMBtu.

In this example, Alaska's royalty gas would share the cost of service in Alaska as far as Fairbanks. South of Fairbanks, the percentage of throughput consumed as fuel would decline in relation to the case involving full deliveries to the lower-48 States, and the U.S. share of operating costs in Canada would decline. The unit capital charges on the other hand, would increase. The net of these factors would increase the 20-year average cost of service to the lower-48 States by about 8 cents per MMBtu. The increase would be higher in early years; the average increase for the first 5 years would be about 13 cents per MMBtu.

These figures assume that the withdrawal of Alaska gas was contemplated at the time transportation contracts were executed, but that the pipeline was not redesigned for lower volumes. Whether redesign would occur would depend upon the assessment of need for economical expansibility.

It is important that the question of whether Alaska will withdraw its royalty gas for use in the State be resolved prior to the final certification of system design and execution of transportation contracts both in this country and in Canada. The Federal Energy Regulatory Commission (FERC) has so recognized in its recent report to Congress and should be expected to consider the question of appropriate design capacity for the system in light of Alaska's expressed desires in this matter in the course of its final certification proceedings.

Senator STEVENS. Assuming those provisions will be negotiated, the ability of Alaska to use royalty gas in Alaska is considerably improved, and the probability of its use in Alaska is very great.

I would say that anyone that proceeds to compute the financeability of this line on its throughput based on eight-eighths of the gas is not looking at the total reality of the situation in our State.

Secretary SCHLESINGER. I think that does raise a point, Senator, that we will have to review.

Senator STEVENS. I would appreciate it if we could do that. You mentioned the Loeb-Rhodes concept. I understand they said that financeability is contingent upon marketability, risk, and certainty of Government regulation.

Secretary SCHLESINGER. I am sorry—marketability, risk, and what else?

Senator STEVENS. Marketability, risk, and certainty of Government regulation. Is it not premature to make a conclusion as to whether the line is financeable if certainty of Government regulation is one of the questions?

Secretary SCHLESINGER. I underscore that point, Mr. Stevens, because we included such a reference in the recommendation of the President.

To the extent that the regulatory regime is altered, that that raises questions about financeability particularly because it directly impacts on the proposed price of natural gas.

We would have to have firm contracts and firm prices for natural gas before the project could be financed.

Senator STEVENS. The chairman has been very patient with me. I have three more questions. One is the position of the administration as I take it is that producers of the Prudhoe Bay field should not participate in an equity position in this pipeline.

But you have indicated that they, too, should be encouraged to participate in guarantees of the financing. During the consideration of the three proponents' applications, I, personally, undertook to contact all of the producers and urge them to particiapte in financing.

I would be glad to make the letters available to you and the committee. I think I did make some of them available to your staff, where all of the producers indicated that they were unwilling to take such a position and did not feel that it was their role to participate in guaranteeing financing of a project of this type.

Have you any indications to the contrary that the producers will, in fact, change their position and now become guarantors of the transportation system costs?

Secretary SCHLESINGER. That, of course, was their negotiating posture, Senator. I should underscore that the producers of Prudhoe Bay have very powerful incentives to see to it that a transportation system is achieved. The gas is essentially costless to produce some years down the line.

The inability to ship gas will become a financial burden of sorts on the companies, and the shipment of the gas will give them on the order of $20 to $25 billion worth of profit.

Under those circumstances, I should think they would be eager to provide whatever margin is necessary to assure the success of this transportation system.

Quite obviously, they may wish to avoid a commitment, but in the final analysis they would not want the project to fail.

Senator STEVENS. Let me direct your attention to page 124. It is part of the same question. The indication there is that these assurances should be for cost-overrun financing.

The previous reference was to guaranteeing of financing. Do you envision the State of Alaska and the producers being involved in guaranteeing the cost-overrun portion of this financing, or of the basic financing?

Secretary SCHLESINGER. I think the answer to that is either possibility, Senator.

Senator STEVENS. I am put in the strange position of the cost overruns on the Alcan were projected by the staff to have the greatest potential. The people who opposed that—including my State—if they are to be put in a position of guaranteeing the cost-overrun project, they warned against approval because of cost overruns.

It seems to be a rather strange position for the administration to take. I would hope that that particular subject would not be the area for participation for my State.

Let me turn to the second question I had in mind, and that is, throughout this decision and report is the indication—if I believe correctly—you once said in my presence that there is a belief that there would be increased amounts of gas beyond the current total of committed contracts from Canada available to U.S. consumers if the Alcan project is completed.

My question to you is: Have you any commitment from any government official or agency in Canada that the limitation currently existing upon the export of gas to the United States, contracts already entered into, will, in fact, be expanded, and we can expect increased Canadian exports beyond the current level of commitments in existing contracts if this project is approved?

Secretary SCHLESINGER. There are two aspects to that question, Senator, I believe. In the first place, the commitments in existing contracts are not so much commitments because they are subject to national need in Canada.

I think it is quite clear that we will get more gas than we would otherwise have received because the Alcan line will be built.

There was every likelihood that there would have been further reductions in the amount of Canadian gas moved into the United States as a result of potential restraints in Canada.

Senator STEVENS. Even with the Alberta surplus, and with the increased amount of surplus projected under the national needs formula of Canada. Do you believe that without this project the United States could not have expected Canadian exporters to live up to the commitments of existing contracts?

Secretary SCHLESINGER. I said there was every likelihood and there was a difference between what is pragmatically going to be the case and what is committed to.

I would underscore that every indication we had from the Canadian Government in the past has been the possibility of further reductions in gas shipments.

It was plain in our discussions with the Canadians as a result of the construction of the Alcan project the likelihood of the maintenance or augmentation of existing contracts was enhanced.

There is no question, it seems to me, that we will get more gas when we need that gas, as a result of time swaps. But we have also had indications from Canadian Government officials that there will be an augmentation of the gas flow from Canada.

Now, if by "commitment" you mean: Do we have a hard, firm contract? No; we do not. But we have every indication that that will be the case.

Senator STEVENS. Part of your proposal is that U.S. consumers should pay the cost of the Dawson diversion, if it is built.

Secretary SCHLESINGER. The reason for paying the cost of the Dawson spur—I assume you are referring to the Dawson spur?

Senator STEVENS. Yes.

Secretary SCHLESINGER. It is because we avoid the costs associated with the Dawson diversion. That is far cheaper, from our standpoint.

As you will recall, Senator——

Senator STEVENS. Let us make sure we are talking about the same thing. It is the lateral that will have to be built to go up and connect with the Dempster lateral if the Mackenzie River gas is to be placed into the Alcan line; are we in agreement with that?

Secretary SCHLESINGER. That is right, the spur from Dawson to White Horse. The reason for that is that the only approved pipeline route, as of the Fourth of July, was the pipeline route that included the Dawson diversion departing from the Alcan Highway and swinging east out of Alaska to Dawson.

That would have been far more expensive from our standpoint, and by going to this agreed position with the Canadians, we will save American consumers something on the order of 8 cents per 1,000 cubic feet as compared to the NEB decision.

Senator STEVENS. That is only if you assume we would have been stupid enough to build a $1 billion Dawson bulge to carry Alaskan gas northeast, in order to pick up the Mackenzie River Delta gas.

That spur was never needed to meet the U.S. consumers' needs; was it?

Secretary SCHLESINGER. That is correct. But that happened to have been the only approved route. That was the route that was approved by the NEB.

That route would have cost $1.12—that decision would have cost $1.12 for the American consumer. As a result of the negotiations, we have reduced the costs to the American consumer to $1.04.

Senator STEVENS. If we are to pay a portion of the cost of the Mackenzie River transportation system, are we to get a portion of Mackenzie River Delta gas?

Secretary SCHLESINGER. In all likelihood; yes.

Senator STEVENS. Do you have any assurance of that?

Secretary SCHLESINGER. We have no commitment, if that is what you are suggesting.

Senator STEVENS. Has any responsible Canadian official stated publicly that he would recommend that the Government would make available Mackenzie River Delta gas for export to the United States, if the U.S. consumer pays a portion of the cost of that Dawson lateral?

Secretary SCHLESINGER. I think there have been indications of a desire to export some portion of that gas to the United States.

Indeed, one of the reasons that the participation in the spur seemed to us to be a relatively low-contingent risk is the expectation that a substantial part of the cost of service would, in any event, have been borne by American consumers, simply because Mackenzie Delta gas is likely to be the gas that comes through to the United States.

Senator STEVENS. It seems to me to be another Peace River dam. It seems to me to be another one-sided commitment of the United States to Canada, and it makes sense only if we are to get a portion of the Mackenzie River Delta gas.

Let me go to the last note. The chairman is getting a little disturbed with me here. The Canadian Government has apparently made a clear public statement that settlement of the native claims in the Yukon will not delay the project, and the cost of settling claims will not be imposed on U.S. consumers.

Why was that commitment not made part of the agreement?

Secretary SCHLESINGER. Because that is an internal Canadian matter on which the agreement, I think, was contingent. But it is still an internal matter, and the United States has no responsibility for settling the Canadian claims or to intervene in matters internal to Canada.

Senator STEVENS. We have entered into the internal matters, the Lysyk Commission report indicates no construction should be permitted in the Yukon until at least August of 1981.

The agreement sets a target date prior to that for commencing construction in August 1981. You have entered into an internal Canadian matter already with regard to the Canadian claims.

You have agreed with the Canadian Government that construction should take place before the responsible Canadian authorities indicated it would be safe to commence construction.

My question is: Since we have gotten in that far, why did we not get an absolute commitment from the Canadian Government, rather than a statement of principles, that the Canadian native claims will not be assessed in any part against the U.S. consumer?

Secretary SCHLESINGER. Senator Stevens, on page 48, we lay out the timetable. Let me reiterate that Lysyk role was merely an advisor for the Canadian Government, and that the agreed-on timetable is one that is different from the Lysyk report.

Senator STEVENS. I know that.

Secretary SCHLESINGER. We, of course, are quite interested in the joint timetable for proceeding, because that affects directly the cost of service to the American consumers.

Once the Canadians had agreed that the resolution of the native claims issue was no responsibility of the United States in any way, and that the cost of such settlement would in no way be imposed upon American consumers, that seemed to us to be the most satisfactory way of resolving that issue.

Senator STEVENS. What are we going to do if they do assess the charges and they assess them against other pipelines, too?

What are we going to do? This is the largest pipeline system through Canada. If they assess charges to all pipelines to assess native Canadian claims, there is no discrimination.

If I understand the investment ratio, it would be about 1 to 1. We would pay half of the native claims, if all the native claims were assessed against all pipelines in Canada, and that would be consistent with the treaty, Mr. Schlesinger.

Why was that not in the agreement, that no charge would ever be assessed against this pipeline for the settlement of those claims?

Secretary SCHLESINGER. It is an internal Canadian matter, and it struck us that it would be inappropriate for us to press what is an internal Canadian matter.

The agreement indicates that only those charges which are just and reasonable or in the event of unexpected developments limited to acts of God and the like would be appropriate charges to make against the pipeline.

Senator STEVENS. Let me say—I will ask my last question. Let me preface this by saying that if you had decided the other way and chose the route that most Alaskans supported, the table would be filled, and you would be here for days.

I think you should realize that the fact that we are prepared to assist in any way possible to get this line built is demonstrated by the position that our State has taken so far on the decision, particularly after El Paso withdrew.

I do think, though, that it is incumbent upon the Congress to make certain that the decision that the President is recommending has the capability of fulfillment within the time frame of necessity for U.S. interest.

I see nothing coming from Canada that indicates, other than the language in the agreement that says that construction ought to commence by a certain date, that indicates a Canadian interest in our time frame for construction yet.

I hope that the Congress will find a way to assure itself that the Canadian Government, not only the Federal Government, but the Provincial governments are ready to react within the time frame of necessity, as far as our national needs are concerned.

I have a lot of other questions, perhaps when my colleagues get through I can come back again. With regard to tax ceilings, we have nothing in the record, as I understand it, on tax rates.

Could you provide for us tax rates that are applicable in Canada now?

Secretary SCHLESINGER. Yes, sir.

[The following was subsequently supplied for the record:]

The primary taxes which will be applicable to the pipeline project in Canada are Federal and Provincial taxes on corporate income, and property (ad valorem) taxes applicable within the Provinces and municipalities traversed by the pipeline. Corporate organization fees will also be imposed on the company which will be created to own the pipeline in Canada, and Federal and Provincial sales taxes will be levied on certain purchases of materials and equipment used in constructing the pipeline.

1. Federal tax rates

(*a*) Corporate income tax—46 percent, subject to a 10 percent abatement for Provincial income tax. (Ten percent of a corporation's taxable income earned in a Province may be deducted from the Federal tax otherwise payable.)

(*b*) Corporate organization fees—Canadian $600 plus 25¢ per $1,000 in excess of Canadian $500,000.

(c) General sales tax—Much of the expenditure associated with construction of the pipeline will be exempt from this tax. However, pipe, valves and fittings are subject to a 5 percent sales tax, and compression equipment is subject to the 12 percent general sales tax.

2. Provincial tax rates

(a) Corporate income taxes:

Alberta—11 percent of the taxable income earned in the Province;

British Columbia—15 percent of the taxable income earned in the Province; and

Saskatchewan—14 percent of the taxable income earned in the Province.

(b) Property taxes:

The property taxes which apply to piplines in the Canadian Provinces are based on valuations of pipeline assets which are contained in the respective Provincial tax codes. Typically, pipeline assessments are according to schedules of pipe diameter valuations per unit of length; buildings and machinery have separate valuation procedures. In Alberta and Saskatchewan, only local governments collect property taxes. Those taxing authorities adjust their millage rates such that, when applied to the valuations determined according to the Provincial tax codes, their revenue requirements are met. The average annual tax rate is now 8.8 percent of assessed value in Alberta, and is expected to increase to 9.5 percent in Saskatchewan this year.

The Province of British Columbia taxes pipelines and buildings at 1 percent of their assessed value annually. School districts and municipalities tax these facilities plus the value of machinery at an average of 4.6 percent per year. Additionally, the right-of-way is taxed at Canadian $27.50 per acre.

(c) Sales taxes:

Alberta has no sales tax.

Saskatchewan and British Columbia have sales taxes of 5 percent and 7 percent, respectively, of the sales price of tangible personal property. In both Provinces, sales tax is paid on the purchase of materials and equipment by the project sponsors or their contractors. Installation of materials and equipment is considered an improvement to realty and is not taxable. Hence, sales tax will be paid on tangible items bought for installation of the pipeline, but the labor and administrative costs associated with installation are not taxable.

3. The Yukon Territory

The Yukon Territorial Government (YTG) has no Territorial income tax. Instead, the full 46 percent Federal income tax applies to enterprises operating in the Yukon, and the YTG receives a grant in lieu of taxes from the Federal Government. The size of the grant is based on the taxable incomes of the enterprises doing business in the Yukon.

Likewise, there is no sales tax in the Yukon. Property taxes are covered by the Agreement on Principles; they start at Canadian $5 million in 1980, and go up to Canadian $30 million in 1983 and thereafter, adjusted for inflation.

Senator STEVENS. With regard to taxes, the agreement says that as far as the Yukon is concerned, and that is a Federal territory and can be committed by the Federal Government, there is a nondiscriminatory provision and because there are no pipelines in the Yukon, there is legitimately and logically a ceiling in the agreement.

However, if the Demster lateral and the Dawson spur are built, there then will be pipelines in the Yukon. And, as I understand it, the ceiling then comes off, because it is only applicable so long as there is no pipeline.

What assurance do we have that there will then be a tax rate that will be reasonable under the circumstances?

Secretary SCHLESINGER. The same assurance that we have, Senator Stevens, generally under the treaty, which is nondiscriminatory treatment.

Senator STEVENS. We are paying part of the cost of their pipeline to start with, so the taxes could be imposed against that pipeline by Canadian interests could, of practice, be higher, since it would be the only pipeline in the Province.

It would seem to me that that is—I respectfully suggest—a loophole in your agreement, and there should have been something to assure what the tax treatment would be, once the pipeline, partially financed by U.S. consumers, in the Yukon was constructed; what the level of taxation against the pipeline carrying Alaskan gas should be.

I just make that comment. I thank you. I do have other questions and my State has some other questions, but I have monopolized the morning and I, again, express my thanks to my colleagues and to you and to your staff, Mr. Goldman in particular, for cooperation in keeping us informed as we went through these negotiations.

It is not an easy proposition to be put in the position of representing a State that is resource rich and population poor, and, to a certain extent, not totally involved in those negotiations, as were the Canadian Provinces.

I still believe we should have been involved more, and before we are through, I think we probably will be, but that will have to be determined by our State.

I thank the two gentlemen for their courtesy.

Senator McClure [presiding]. I would say to the Senator from Alaska that we have one more witness this morning, and I think he would be interested in questioning that witness as well as to make the comment that any written questions you desire to submit will be submitted, so we can get the answers to those questions in writing.

With that, I will yield to the Senator from New Mexico.

Senator Domenici. Let me say, Mr. Chairman, and to the Senator from Alaska, I will be brief and because of your involvement and expertise I would be delighted to yield as much of my time as you might need.

I want to ask a couple of general questions first, Dr. Schlesinger. I am not as familar with this overall arrangement as is my friend from Alaska.

With reference to the kinds of delays that have occurred, heretofore, when we tried to construct a major pipeline, Alaskan pipeline, what is there in this agreement that gives more certainty to the construction phase than was in that proposal?

Are we apt to be delayed by things we are not aware of? Litigation, and the like, even if Congress approves this arrangement, or have we provided some very specific authorities that will minimize the delays?

Secretary Schlesinger. I think if one reviews the Alaskan oil pipeline history—Senator Stevens is familiar with it—the principal source of delay emerged from the governmental decision process.

The discussion started in 1969 and it was not until 1973 that the Congress moved to brush away some of the problems associated with construction of the line.

So we had a 4-year delay, simply from an impasse. Whereas the natural gas pipeline, the Congress learning from experiences in the case of Alyeska, has legislated a formula to avoid these kinds of political or decisionmaking delays.

Senator Domenici. So, Dr. Schlesinger, the environmental concerns that were some part of the delay will be protected by the formula in this agreement; is that correct?

Secretary SCHLESINGER. Yes; I think if you read on page 145 of the decision and report, that you have somewhat more detail on this issue.

As you know, in that case there was a conflicting jurisdiction of the Federal agencies involved, and a duplication of effort, frequently conflicts among them. What we are proposing is a limited reorganization plan that would be sent to the Hill so that all of the authorities and powers of these several Government agencies would be in the hands of the Federal inspector who would be appointed for this purpose, and he would be confirmed by the Senate.

Senator DOMENICI. So what we are saying is that the protection will evolve with the reorganization when it comes to the Hill and if it is basically suggested, then that inspector will have the authority to take care of the environmental issues and all the other issues?

Secretary SCHLESINGER. Yes, sir.

Senator DOMENICI. Just two other questions. If Canada uses this line to bring us natural gas, their natural gas is unregulated in terms of price as far as the U.S. consumers are concerned?

They will sell it for whatever they want under Canadian law, not subject to our regulatory price mechanism; is that correct?

Secretary SCHLESINGER. That is correct. I should modify that. Not for whatever they want under Canadian law. They will sell it at the price agreed upon through negotiation.

Senator DOMENICI. On the other hand, our regulatory scheme is not binding upon——

Secretary SCHLESINGER. Yes, sir, that is correct.

Senator DOMENICI. Third, there is a great deal of discussion in this report, trying to tie it in some way to what the Congress does on the pricing of natural gas, new versus old, price controls, no price controls, will it be $1.45 or $1.75?

I try to read that part to see how it is relevant, and aside from your abiding interest in the American consumer, where you have one version of how they get the best out of natural gas pricing and others have another version.

Aside from that concern, is there anything else relevant to this that has to do with what kind of natural gas law we pass?

Secretary SCHLESINGER. Yes, sir, the question of financing, in this case. As I indicated, I think in response to Senator Jackson's question, the financing depends upon the signing of firm contracts.

We must have firm contracts. Under the existing regulatory scheme, the establishment of firm prices is fairly simple.

Whereas, under the possibility of deregulation there is no simple procedure at all. The producers testified before the Federal Power Commission that they would expect to get in the deregulated market $3.82 per 1,000 cubic feet.

At $3.82 per thousand cubic feet plus the cost of transportation, even if it remains at $1.05 in view of potential delays under those circumstances, one is talking about natural gas at something in excess of $5.

That of course, implies that it has become more expensive than synthetic natural gas. How much the producers in an unregulated market would receive from their initial demand for $3.82, I do not know.

But I know that under those circumstances the issue of pricing would be up in the air, that it could lead to delays in getting firm contracts and firm prices, which are a prerequisite for financing.

Senator DOMENICI. Who would be waiting for these firm contracts? You are talking about certainty versus uncertainty?

Secretary SCHLESINGER. That is right, the various financing houses, insurance companies, investment houses, would expect before they proceeded with the financing would be able to say, indeed, that there are firm contracts in hand.

Unless there are firm contracts they cannot build the pipeline, and, in principle, there is no gas to be delivered.

Senator DOMENICI. If I understand you correctly, then, what you are tellings us is that the marketplace for financing this project might respond quicker and more favorably to a regulated market under your proposal to the President than they would under deregulation.

Secretary SCHLESINGER. That puts it very well.

Senator DOMENICI. If the outcome were to the contrary, then the pricing scheme would have very little to do with this construction, other than your abiding conviction that the consumer might be forced to pay more; is that correct?

Secretary SCHLESINGER. What you are saying is that you are dismissing, that you might be dismissing the issue of whether or not the uncertainties involved here might delay the project.

And, if so, is there any other issue other than the question of the division of the spoils between consumers and producers?

Senator DOMENICI. Correct.

Secretary SCHLESINGER. The answer to that is "no."

Senator DOMENICI. As a general proposition, I really find it rather incredulous that it will be harder to finance this pipeline under your regulated scheme than deregulated.

That is just an intuitive feeling at this point, but obviously we will have to get some additional testimony on it and make our own decisions.

I find it rather strained in terms of the marketplace, but I understand your reasoning and I thank you for your answer.

Senator MCCLURE. I have just a few questions. I would comment at the outset that I am a little puzzled at the fact that the White House made a public announcement on September 9 of this agreement, but the agreement was not available to the members of this committee until this past weekend.

That makes it a little difficult for us to have gone through the agreement and to try ferret out what might be matters of concern to us, and I would express—it may be necessary as a result of that to submit more questions in writing at a later time for answer, and perhaps we will delay our committee deliberation, rather than expedite it.

On page 8 of your statement, Mr. Schlesinger, with reference to the agreed increased capacity from White House southward, it says: "A higher capacity system will then be installed south of White Horse."

Do you mean at the time the Dempster Lateral is completed or at this time?

Secretary SCHLESINGER. No, sir, at this time.

Senator MCCLURE. Then it also suggests that the cost of the—if I might refer to page 7 of your statement, the front-end $200 million impact assistance payment, which you say is avoided, the agreement eliminates that, but it eliminates it as is shown on page 11 of your statement, by saying that any required impact payments needed in advance of taxes will be treated as a loan.

I assume that is what you are referring to; is that correct?

Secretary SCHLESINGER. Yes, sir.

Senator MCCLURE. So if there is $200 million of impact payments required, those will be loans by the constructors to the Government, to be deducted from future tax payments; is that correct?

Secretary SCHLESINGER. That is correct, and there is a complex financial arrangement between the contractors and the Canadian Government that I will not go into, but could be available for the record.

In any event, it does not impact the cost of service for American consumers.

Senator MCCLURE. Will those impact payments be discounted for interest?

Secretary SCHLESINGER. Yes, sir.

Senator MCCLURE. So the interest, if any, will be paid out of future tax revenues?

Secretary SCHLESINGER. Yes.

Senator MCCLURE. Is that applicable to all of the Provincial governments and their subagencies

Secretary SCHLESINGER. No, that is the only impact payment.

Senator MCCLURE. That is the only impact payment?

Secretary SCHLESINGER. Yes, sir.

Senator MCCLURE. There is a statement with regard to the limitation on taxes for the Yukon. Is there any similar arrangement with limitation on taxes on the other provinces

Secretary SCHLESINGER. The Yukon, of course, is a territory. It is unique in two respects. First, it is a territory, rather than a province.

Second, there are no other pipelines in it and, therefore, at this time the treaty requiring nondiscrimination, while relevant, while binding the Canadians, it is not particularly relevant to the Yukon, because there are no other pipelines.

And they cannot have any efficacy in a nondiscrimination clause for any pipeline. The provinces, of course, are in a different position, and they are bound by the treaty.

Senator MCCLURE. The only limitation on tax burden, then, will rely upon the nondiscrimination provisions of the current treaty?

Secretary SCHLESINGER. No, the treaty is augmented by our understandings in the agreement, which state that only acts of God and what-not would be the basis for increases of cost beyond what is just and reasonable in accordance with traditional practices of regulatory bodies, such as the FPC or NEB.

Senator MCCLURE. Is there any limitation in the existing treaty with regard to throughput taxes?

Secretary SCHLESINGER. They are nondiscriminatory, and that is the only protection that I am aware of, Senator.

Senator MCCLURE. Then they could impose a tax on U.S. gas, passing through this line as a means of raising revenue for the provincial government or its subagencies.

Secretary SCHLESINGER. Yes; but they would have to impose a similar tax on all Canadian gas——

Senator MCCLURE. I understand that, but the major volume of that gas is destined for U.S. markets and they have a way, indeed, of raising revenues on this without respect to the limitation on taxes expressed in this agreement.

Secretary SCHLESINGER. I think we would have to do a careful analysis in view of the total dependency of Canadian consumers on the network of Canadian pipelines. It would seem at first blush that the impact on Canadian consumers would be greater.

This seems to us to be a hypothetical case, but it is one we will pursue for you, Senator, and place it in the record.

[The following was subsequently supplied for the record:]

The State Department has informed us that throughput taxes are prohibited by the Transit Pipeline Treaty, although throughput may be used as a factor in calculating taxes such as property taxes. Article III reads as follows:

ARTICLE III

1. No public authority in the territory of either Party shall impose any fee, duty, tax or other monetary charge, either directly or indirectly, on or for the use of any Transit Pipeline unless such fee, duty, tax or other monetary charge would also be applicable to or the use of similar pipelines located within the jurisdiction of that public authority.

2. No public authority in the territory of either Party shall impose upon hydrocarbons in transit any import, export or transit fee, duty, tax or other monetary charge. This paragraph shall not preclude the inclusion of hydrocarbon throughput as a factor in the calculation of taxes referred to in paragraph 1.

Paragraph 2 effectively guarantees "in bond" treatment for the hydrocarbons of either nation which transit the other.

Senator MCCLURE. I am concerned about it because I remember when the world oil prices received the impetus of the embargo and prices doubled and tripled and quadrupled and doubled again, that our friends to the north immediately levied taxes upon the gas that was being supplied to us by contract, and successfully obviated the limitations of the contracted agreements, and got the world price equivalency for the gas which was being supplied under existing contracts.

That is not the background against which we can conduct these negotiations with a great deal of assurance that they may not attempt something like that again, if they can find means by which they can load the cost on the American consumer.

Secretary SCHLESINGER. In that particular case, Senator, there is no treaty applicable.

Senator MCCLURE. No; there were just binding agreements.

Secretary SCHLESINGER. In this case they are bound by the treaty.

Senator MCCLURE. There were binding agreements then but they obviated by them by the indirect route of taxation. As I understand, these agreements refer only to direct taxes.

Secretary SCHLESINGER. There is no preclusion of taxing in the contracts to which you refer. By contrast, in this case we have a requirement for nondiscrimination and we have a limitation on the Alcan tax regime, which I think gives ample protection to the American consumer.

Senator MCCLURE. You are dependent upon the fact that in the existing agreement between the United States and Canada there can be no discriminatory tax and, therefore, any tax which is levied must be levied also against their own consumers.

Secretary SCHLESINGER. That is indispensable, it seems to me, in our approach to this problem.

Senator McClure. Are the provinces bound by that treaty?

Secretary Schlesinger. If you look at pages 81, 82, and 83, we have statements from the three provinces, and their indication that they would enter into firm agreement with the central government of Canada regarding their respect for the principles of that treaty.

Senator McClure. That is an indispensable precondition as far as the Senator is concerned, based upon our past experience.

Secretary Schlesinger. We so regard it, Senator, and we share that concern.

Senator Stevens. There is no national Canadian benefits analysis in the President's report. Do you have any statement of what will be the total taxes, the total estimated payments over the period of the years to Canada?

I think there was one prepared to in the negotiations.

Secretary Schlesinger. There is no inclusion in the report, we should be happy to make it available in the record.

[The following was subsequently supplied for the record:]

The benefits to Canada from the Alcan system are substantial. Over the 20-year period, 1984–2003, total tax revenues to the Federal and Provincial (Territorial) Governments and total cost-of-service payments to the Canadian pipeline companies are projected for the expected cost overrun case to be:

[In billions of dollars (nominal)]

	Total system	U.S. share
Canadian income taxes	$2.418	$1.965
Canadian ad valorem taxes	1.613	1.268
Total cost of service (excluding fuel)	20.870	16.676

Senator McClure. On page 6 of your statement you talk about the need to assure future shipment of natural gas from the Gulf of Alaska, which may require liquid natural gas deliveries to the west coast.

Under what conditions would that be necessary if, as a matter of fact, there is availability to both California and the Pacific Northwest through the Pacific Gas transmission line permits interconnection with the Alcan project?

Secretary Schlesinger. The point here is that it may require it and it may not.

Senator McClure. Is that provided for under these contracts, under these agreements?

Secretary Schlesinger. No, sir, there is no provision with regard to that. All that this refers to is that if the El Paso project had gone ahead at this time, that we would be overloading the west coast with liquid natural gas and that would leave little latitude for the future introduction of liquid natural gas from the Gulf of Alaska.

By contrast, that particular capability for absorption will not be utilized at this time and will be available in the future.

Senator McClure. You are referring to the conflict in the landing and distribution facilities of the west coast.

Secretary Schlesinger. I think it is landing and distribution facilities that will continue to be available, from our point of view.

Senator McClure. Thank you very much, Mr. Schlesinger. Again, I will say that when I have had an opportunity to read this voluminous report, I may have some additional questions to be submitted in writing.

Having seen it for the first time this morning, I could not represent that I have had a chance to analyze it very carefully.

Secretary SCHLESINGER. There is one point that I should call to your attention, Senator, in light of the questions that you were raising, and that is the section that begins on page 63, item 12, so called other costs.

That is specified in the agreement. It is understood there will be no charges on the pipeline having an effect on the cost of service, other than those imposed by a public authority as contemplated in this agreement, or in accordance with the treaty, second, caused by acts of God and other unforeseen circumstances, or third, normally paid by natural gas pipelines in Canada, in accordance with accepted regulatory practices.

I stress this particular element because it underscores our concern with the issues that you've raised, Senator, and this was referred to when we included it in the agreement as the cap of caps.

Senator McCLURE. I appreciate that. I will be looking at it with a great deal of interest as we go forward, and develop these agreements with the Provincial governments. Having once gone through these agreements, we're not likely to walk into it again without some trepidation. We've gone through it at least twice, it has been referred to on the Columbia River Treaty and again on the adjusted cost of Canadian gas delivery in the American market.

In my State, we are better than 60 percent deregulated right now, and the threat of deregulation is somewhat different in my area of the country than it might be in other areas where our Government still controls price because our Government has not controlled price in the delivery of Canadian gas.

Secretary SCHLESINGER. I think, Senator, that the price of Canadian gas coming into the United States reflects the existing regulatory regime in the United States, and our negotiations with the Canadians have been on that basis.

In a deregulated market, if the price of new gas were to go to $4.50, or thereabouts, that would be immediately reflected in a substantial increase of Canadian gas export prices to the United States.

Senator McCLURE. I'm sure they would find a way to do that. I have no question on that score.

Secretary SCHLESINGER. They would have an obvious way to do that.

Senator McCLURE. If, on the other hand, the price of deregulated natural gas or price in a natural gas deregulated market did not go up, their price would not either, presumably.

Secretary SCHLESINGER. That is correct.

Senator McCLURE. Assuming that the consumers do not participate in project financing, if they elect not to participate, can the project be financed without U.S. Government or consumer participation?

Secretary SCHLESINGER. I think the answer to that is "yes". It is easier to finance it if there is producer participation in the financial arrangements.

Senator McCLURE. The FPC report to the President states to the contrary. Maybe your conclusion is different from that of the FPC.

Secretary SCHLESINGER. Yes, sir, there have been new developments in the financial area, which we covered somewhat earlier in the discussion with the chairman.

Senator McCLURE. If I understand, the project will not be financed with an all-events tariff.

Secretary SCHLESINGER. That is correct.

Senator McCLURE. I understand that to mean that the pipeline company is allowed to amortize in all of its tariff where the pipeline company is allowed to amortize its debt through collection of the rates from the consumer, even if the project is not completed, the noncompletion risks.

In periods of extended service interruptions, and in case the project is abandoned after service has commenced. As I understand the administration proposal is a modified all-events tariff, sometimes called a minimum-bill tariff.

Secretary SCHLESINGER. Yes, but it is no modification of an all events tariff. It is a non-all-events tariff, which is as far as one can get from the all-events tariff. It is a some-events tariff, in effect.

Senator McCLURE. Whether you call it a modified all-events or a some events, or a minimum-bill tariff, I understand that the term means that the pipeline company is still protected against the risk of flow interruption and abandonment, but not in the case of noncompletion.

Am I correct in my understanding?

Secretary SCHLESINGER. It is not protected in the case of abandonment. In that case the equity would be wiped out. What we have planned here are three types of tariffs, an all-events tariff, a cost-of-service tariff, and a minimum-bill provision.

Cost-of-service tariff basically says there is a temporary interruption in the service, there will be a continuing charge to the customers for the cost of service that continues during this period of interruption.

It does not apply to noncompletion and it does not apply to abandonment but during a period of interruption. A minimum-bill provision is a modification of that cost-of-service tariff that in the event of service interruption what one does is to reduce or eliminate the equity charges associated with the cost of service during that period of the interruption.

That generally is what we have agreed upon with the Canadians.

Senator McCLURE. As I recall, or as staff has reminded me, every investment advisor testifying during the FPC hearings said that the lenders, being fiduciaries, will not undertake any of the three risks under the all-events tariffs.

If that is true, then someone has to underwrite the risks that are included in the administration proposal. Who is that someone, as you see it. If the Government is not to be involved then you cannot get financing for the risks which are included in the minimum-bill tariff, who then will be the guarantor to make the financing possible.

Secretary SCHLESINGER. The entrepreneurs are the ones that underwrite the risk. What we have here is a case in which a set of companies has an application to build a pipeline. They have equity in the companies that underwrite the risks until such time as service starts up.

They are entitled to a continued payment for service, even in the event of temporary interruption. But in the event of abandonment of the pipeline their capital is once again at risk.

Beyond that, the lenders are at risk under those circumstances, and last of all the consumers.

Senator McClure. As I understand the evidence, the testimony of the investment advisers was that the lenders were not—would not be willing to assume those risks and, therefore, there would be no financing.

Secretary Schlesinger. The risks will be borne principally by the entrepreneurs and by the equity of the pipeline. This is a pipeline that is believed to have proven technologies, and outstanding economics in an area of high and steady demands.

Consequently, it is believed that the risks of failure in a proven technology or failure in the market is very low, and those are risks that the entrepreneurs are willing to take.

Senator McClure. If I could summarize your answer, and if I try to boil it down to a simple answer that I understand, please tell me if I have oversimplified. But what you are simply saying is that you disagree with all of the evidence of the witnesses.

Secretary Schlesinger. They, of course, were dealing in the abstract. We happen to have a concrete project before us. They were dealing with some type of hypothetical possibility. I think that the answer on that point is: While lenders may say that they bear no risk, they may even tell those from whom they have borrowed that there is no risk; there is.

Senator McClure. And they may also say that they don't want to accept any risk in the hope that somebody will relieve them of it.

Secretary Schlesinger. Yes, sir.

Senator McClure. I have no way of evaluating that except that I can look at their testimony and they say it just isn't going to happen. You say it will happen, financing can be arranged. Thank you very much.

We may submit some additional questions in writing for your response, thank you.

Secretary Schlesinger. Thank you, Senator.

Senator McClure. We have one further witness this morning, and that witness is Mr. Canfield, the Director of the General Accounting Office.

Mr. Canfield, we have your prepared statement. You may summarize it, it will appear in the record in full, and you may proceed as you wish, in whatever form you wish.

Mr. Canfield. Mr. Chairman, it would be important for me to know whether you would prefer it summarized or not. It is a very detailed problem and I would prefer to read it, but in view of the time it might be preferable from your point of view if I summarize it.

Senator McClure. Well, I have your prepared statement and you might hit—I realize in a detailed statement you might think that each one of the details is as important as the others and, therefore, hard to highlight. I have your statement. It will appear in the record, and as you will note there are no other members of the committee here at this time, so the reading of it would benefit only me, and I don't need that benefit. But that's up to you.

Mr. CANFIELD. I anticipated this and I am delighted to summarize it for you. I will go through it and you can follow it as we go.

Senator McCLURE. Thank you.

STATEMENT OF HON. MONTE CANFIELD, JR., DIRECTOR, ENERGY AND MINERALS DIVISION, GENERAL ACCOUNTING OFFICE; ACCOMPANIED BY VINCENT AROSTEGUI, PROJECT MANAGER; AND KEVIN BOLAND, ASSISTANT DIRECTOR

Mr. CANFIELD. I should identify myself. I am Monte Canfield, Director of Energy and Minerals Division of the General Accounting Office. I have on my immediate left Vincent Arostegui, project manager of our work on the trans-Alaska pipeline, and to my immediate right, Kevin Boland, Assistant Director in charge of our work in this area.

We appreciate your invitation to appear here today to discuss the preliminary conclusions of our study of the plan, and construction of the trans-Alaska pipeline. From our study, we believe there are important lessons to be learned, and we urge that these lessons be applied in the assessment of the gas pipeline which the Alcan consortium plans to build.

We will give you a brief review of the work of our study. On the bottom of page 3, we state that in 1969 the owner companies estimated that a pipeline system for transporting oil from Prudhoe Bay to Valdez would cost $863 million. The final cost, with construction substantially completed, is estimated to be about $7.8 billion.

We examined the basis of the original estimate to determine why it proved to be so low. One factor was the lack of historical experience on which forward projections could be made.

In 1969, there was no experience on pipeline construction in the Arctic. The 1969 estimate was based on limited information available at that time. It was prepared before the pipeline had been designed or engineered and before extensive soil studies were performed.

It was based on material and labor prices prevailing in 1968–69, with no allowance for cost escalation and no expectation of the subsequent 4-year delay in start of construction because of environmental lawsuits.

The oil companies' estimate provided very little leeway for such unforeseen developments. It included a contingency allowance of only about 10 percent even though in normal engineering practice, initial estimates based on an outline design are only expected to be accurate to within a margin of 15 to 30 percent.

Even a 30-percent contingency would have been way off, given the fact that the actual cost will be several hundred percent over the original estimate. While Alcan does now have the experience of Alyeska to draw on, we note that Alcan has included less than a 10-percent contingency allowance in its original $6.7 billion estimate.

Turning to the top of page 5, interim budget estimates. From 1969 to May of 1974, the cost estimate increased several times to reflect more detailed system definition and design, additions to system size and sophistication, delay costs, and the results of cost estimates prepared by outside companies under contract with Alyeska.

Alyeska did not gear up to develop a detailed comprehensive budget until after May 1974, by which time they had already been granted both Federal and State right-of-way agreements.

We note that Alcan's estimate of costs is growing rapidly. In March 1977, Alcan's budget estimate was $6.7 billion, including interest, in 1975 dollars. The administration's current cost estimate for the Alcan project is between $10.5 and $13.7 billion.

Because of inflation, the final costs are likely to be higher than the administration's $13.7 billion estimate. Further, we believe the estimates are likely to increase significantly, exclusive of inflation, because they are based on minimal site-specific data and several important technical uncertainties remain to be overcome.

Skipping to the middle of the page, a budget control estimate of $6.4 billion, as of April 30, 1975, was ultimately developed as a control mechanism and accepted by the owner companies. The base control estimate was the first estimate supported by firm commitments for nearly all permanent materials and for most of the construction equipment, support services, camps, and other temporary facilities.

What were the reasons for the increase over the base-control budget? As pipeline construction proceeded from 1975 to 1977, the control budget was continually revised upward through hundreds of amendments. By June 1977, the approved control budget had increased to about $7.8 billion, about $1.5 billion, or 23 percent, in excess of the control budget.

The principal reason for the increase was that 53 percent more direct labor hours, about 20 million hours, were needed to complete the project than estimated. The direct labor-hour increase was caused primarily by unexpected site conditions and construction difficulties, worker inefficiency, and inexperience, and more winter work than planned.

All these factors were not beyond Alyeska's control. More geotechnical and site-specific work prior to start of construction would have reached the number of surprises encountered once construction started. For example, unexpected subsurface conditions were encountered at the Valdez Terminal site once excavation was started.

This led to much more extensive site preparation work than planned. Also, once ditching operations were started to lay the pipe, it was found that many areas had more groundwater than anticipated. Both of these surprises were costly.

Turning to the bottom of page 8, it is clear that it is in the public interest to insist on realistic initial assessments. The most reliable basis for establishing budget estimates is the development of as much site-specific data as is economically practical.

In the case of the gas pipeline, for example, the earlier and more thoroughly that site-specific work can be done, the better will be the project engineering. If project engineering and system design are based on more complete data, both become less subject to change.

I would like to talk for a moment about project management. When Alyeska was organized to engineer, design, and construct the pipeline system, the oil companies retained control of the project through an owner's construction committee.

Alyeska top management also consisted primarily of personnel on loan from the owner companies. They met monthly with the committee, which made or approved all major decisions.

Going to the top of page 10, the primary objective of management was to complete construction at the earliest practicable date in order to start oil flowing on schedule, and to avoid the large costs to the owner companies that would have resulted from construction delays.

Construction began on April 29, 1974, with the goal of getting oil flowing in the line 3 years later, by the summer of 1977. The project managers' primary objective was to insure that milestone dates were met. If they were not, this meant hiring more workers, paying for more overtime, and/or having more work done in the winter, when productivity was lower.

The managers from the eight owner companies faced strong internal pressures for quick development.

Alyeska's contracts with its management and execution contractors were reimbursable cost plus fixed fee and fixed overhead. The advantage to Alyeska in awarding these reimbursable type contracts was that this form of contract could be negotiated and settled more quickly than fixed-price-type contracts.

Alyeska also lacked adequate information on which fixed prices could be negotiated. Contractors would not bid fixed-price-type contracts because there was no definitive design, and other factors such as soil conditions and labor productivity in extremely cold climates were unknowns.

Under cost-reimbursement contracts, the contractor has little financial interest in controlling costs because his profits are not affected by the final project costs. Thus, the contractor does not have the same incentive to minimize costs as would exist under other contractual arrangements, such as fixed-price contracts.

This type of contract provides the most incentive for efficiency because contractor profits require precise project specifications and detailed design, this is yet another reason why site-specific data should be developed early and thoroughly.

We recognize that it is not always possible to enter into this type contract. However, it is desirable to provide the contractor with such incentives to control costs whenever possible.

Turning to management control systems, the ones in place when construction began in April 1974 were less than ideal. The systems, including cost control, inventory control, and security programs, had to be changed over the 3-year construction period.

For example, Alyeska's cost reporting system initially could not provide up-to-date information on actual costs. The May 1975 budget control estimate was not based on actual outlays because of inconsistent and erroneous coding of costs in 1974 and early 1975.

Furthermore, even though Alyeska's first overall pipeline cost report was not published until September 1975, at that late date the report could not use actual costs, since no central computerized system to collect actual costs had been developed.

It was not until December 1975, the end of the second construction year, that the cost-control system began to function properly.

How a project is going to be managed is clearly important for an adequate assessment of its feasibility. We believe this aspect of the Alcan gas pipeline has been given little attention to date. Although the Federal Power Commission's hearings on the alternative gas line proposals resulted in an impressive volume of information, we noted that most information involved the environmental, technical, and economic merit of each proposal.

Only minimal information on details of project management and control systems has been assembled.

Since Alcan probably will be subject to the same internal pressures for quick development as was the case with Alyeska, we believe it is extremely important for Alcan to develop effective management systems early in the planning phase.

This will enable Alcan management to develop the information required to exercise better management control over project execution.

Alyeska's experience as to negotiating a project agreement shows that the no-strike clause in the labor agreement prevented any sectionwide or projectwide strikes. As far as we could determine, there were relatively few work stoppages for a project of this size—76 as best we could determine.

But they were small and did not last long. On the other hand, there were slowdowns. Although we don't know how many, our discussions with Alyeska and contractor personnel indicated that slowdowns may have occurred often enough to interfere with productivity. We could not determine the significance of this interference since adequate records were not maintained.

We also examined the impact of Government requirements on construction of the Alyeska pipeline, which always seems to be a sore point in this sort of thing. Both the U.S. Government and the State of Alaska granted Alyeska right-of-way agreements to construct the pipeline of public lands.

To protect the public interest in these lands, the agreements contained requirements, many of which were to minimize environmental degradation during construction, with which Alyeska had to comply. To assure that Alyeska did comply, both the State and Federal Governments reviewed Alyeska's system design and construction plans, and monitored construction activities to see that plans were being implemented as approved.

Some disagreements did arise during construction over the meaning of the requirements. Alyeska personnel generally interpreted the requirements less restrictively than Government personnel.

Because of the difference in interpretations, Alyeska had to make some adjustments to accommodate the Government interpretation of the requirement. It was also claimed that the requirements complicated the task of designing and building the pipeline system.

However, in response to our requests, Alyeska did not provide any evidence showing where significant construction delays had been caused by this type of problem.

I would like to turn to the problem of not having an ongoing audit. The right-of-way agreements granted to Alyeska did not contain any requirement that the Government be allowed to conduct an ongoing audit during construction to insure that moneys expended were prudently incurred and, therefore, were an allowable expense to be included in tariff submissions.

As you know, there are—there have been many allegations about mismanagement and moneys being improperly spent by Alyeska.

The Interstate Commerce Commission is currently conducting an audit to determine which costs should be allowable.

Because of the size of the project, this is an extremely difficult task to do within available time constraints. Because it has proved to be so difficult to post-audit the Alyeska project, we believe a decision should be made now that Alcan's costs will be audited during construction.

We believe this would benefit both Alcan and the Government. Alcan would not be left in doubt until project completion as to whether its costs would be recoverable through the tariff.

The Government would be in a far better position to conduct a more effective audit of costs. In this regard, it should be pointed out that no agency of the U.S. Government will have the authority to audit the costs of constructing that portion of the line, about 2,000 miles, that goes through Canada.

These costs in Canada will constitute a significant portion of the total costs of building the pipeline. If they are unrestrained, total costs could increase greatly. We believe the U.S. Government's agreement with the Canadian Government should be amended to stipulate that requirements identical to, or at least similar to, those imposed by the United States, such as for budgeting, management, and audit controls, will be implemented by Canadian Government overseers of the pipeline construction there.

We further believe that a clear and specific requirement must be established in the agreement to provide the Government with direct access to project files and records. At the time of our study, three separate audit groups needed Alyeska data.

To respond to these requests, Alyeska hired a law firm to act as liaison. In the interest of obtaining as much information as possible for these hearings, we agreed to this. While we can appreciate Alyeska's need for the arrangement, it causes us procedural difficulties in getting the information necessary to carry on our review, and left us with much uncertainty about the completeness and accuracy of the information given in response to our requests.

Before turning to two other important aspects of the proposed gas pipeline project, I will sum up the key lessons to be learned from the Alyeska experience, which we hope will be applied to the Alcan project. We should be skeptical of initial and interim cost estimates. Final costs are bound to be significantly higher than these estimates.

We should insist on site-specific data and on thorough investigation of technical and geological uncertainties. This is the only way to avoid unpleasant and costly surprises during development.

Government approval should be contingent on detailed planning for management control including budgetary controls. We believe Alcan should have its managerial house in order before construction is allowed to begin.

We were given no evidence that governmental restraints to minimize environmental degradation created significant complications in Alyeska's construction schedule. This may also prove to be the case with gas pipeline construction.

We should then insist on an ongoing government audit of the Alcan project's expenditures. This is clear from the difficulties of auditing Alyeska costs after construction was completed.

Our agreement with the Canadian Government should be amended to stipulate that an ongoing audit and other U.S. requirements affecting the gas pipeline construction will be implemented during construction in Canada.

I would like to discuss briefly two related issues which are of concern to us, and which, Mr. Chairman, you asked questions about a moment ago. They do not arise as a result of our audit of the Alyeska experience, but stem from concerns we have expressed in other reports dealing with high-cost energy supply situations.

First is the question of Government guarantees of the cost of the pipeline. Considerable discussion developed this year over a so-called "all events" tariff which would amount to a guarantee to return at least debt service and, perhaps, equity should the project not be completed. In essence, such a guarantee would shift the risk from the company to the U.S. taxpayer.

We understand that both Alcan and the administration now say that there is no need for such a guarantee. We also see no need for such a guarantee and support the administration's position.

Should the issue arise again, however, we believe careful thought should be given to whether the Federal Government should undertake such risk. There may simply be much more attractive alternatives for Government risk-taking than the Alcan pipeline. The Government should more thoroughly explore those alternatives before making any such commitments.

That brings me to the second point. Any assessment of alternatives should be made on the basis of incremental cost. The cost of Alcan-delivered gas should be compared at the margin against other energy supply or demand reducing strategies.

This is particularly important since there will be great pressure to roll in the price of Alcan gas when it is delivered to relieve consumers of Alcan gas from a sudden price spike. Whether or not such roll in should be allowed is a question of equity, which can be decided after further study at a future date.

But the actual rolling in of the price should not be confused with the need to base decisions on whether or not to subsidize Alcan on the true marginal cost of that alternative as compared to others.

In closing, I emphasize that our comments should not be construed as taking a GAO position either for or against the eventual construction of the Alcan project. Rather, we believe the final project cost cannot be realistically estimated until more site-specific data is obtained, the technological problems solved, the project substantially designed and engineered, and a base-control budget established.

We expect the current project estimates will be revised upward. Thank you, Mr. Chairman.

[The prepared statement of Mr. Canfield follows:]

STATEMENT OF HON. MONTE CANFIELD, JR., DIRECTOR, ENERGY AND MINERALS DIVISION, GENERAL ACCOUNTING OFFICE

Mr. Chairman, we appreciate your invitation to discuss the tentative conclusions of our study of the planning and construction of the Trans-Alaska Pipeline. As you know, we are in the process of drafting our report, which we hope to complete and issue in a matter of weeks. I would appreciate it if the full report could be made part of the record at that time.

98-069—77——4

Building the oil pipeline in Alaska was a pioneer experience not only for the oil companies and workers involved, but also for the Federal Government. It turned out to be a costly experience, but we now have the benefit of hindsight. From our study, we believe there are important lessons to be learned. We urge that these lessons be applied in the assessment of the gas pipeline which the Alcan consortium of companies proposes to build from Alaska through Canada to the lower 48 states.

We believe, for example, that the costs of building the proposed gas line may be grossly under-estimated. This was the case with the Trans-Alaska Pipeline. From an original estimate in 1969 of $863 million, final costs will be about $7.8 billion exclusive of interest charges.

A significant factor in this under-estimation was that plumbing was based on minimal site data, with several technical uncertainties left unresolved. We believe Alcan's budget estimates will increase significantly, for the same reasons.

Some of these escalating costs may also have been avoided with fixed price contracts, more systematized budgetary controls, and government auditing of costs during construction instead of after construction was completed.

Alyeska gave us no evidence to support its claims that Government requirements to minimize environmental damage during construction caused significant construction delays.

We believe present data may be insufficient to judge the economic feasibility of the proposed gas pipeline. Such feasibility and the need for the system's construction should be weighed carefully in view of pressure which can be expected to build for guaranteed financing of project costs and for rolled-in pricing of the delivered gas. In these cases, financial risks would be shifted from private lenders to the public, as either taxpayers or consumers. We believe this warrants careful consideration before proceeding with the gas pipeline.

I will expand on each of these points and spell out our recommendations in the following brief review of the work of our stndy. It focused on the issues of project budget estimates, project management, and project labor.

PROJECT BUDGET ESTIMATES

In 1970, the 8 owner companies involved in planning the proposed Trans-Alaska Pipeline entered into an agreement to form a separate corporation, Alyeska Pipeline Service Corporation (Alyeska), to act as their common agent to engineer, design, and construct the pipeline system.

The first estimate of construction costs had been developed the previous year. In 1969, the owner companies estimated that a pipeline system for transporting oil from Prudhoe Bay to Valdez would cost $863 million. The final cost, with construction substantially completed, is estimated to be about $7.8 billion.

We examined the basis of the original estimate to determine why it proved to be so low.

One factor was the lack of historical experience on which forward projections could be made. In 1969, there was no experience on pipeline construction in the Arctic. The 1969 estimate was based on limited information available at that time. It was prepared before the pipeline had been designed or engineered and before extensive soil studies were performed. It was based on material and labor prices prevailing in 1968–69, with no allowance for cost escalation and no expectation of the subsequent four-year delay in start of construction because of environmental lawsuits.

The oil companies' estimate provided very little leeway for such unforseen developments. It included a contingency allowance of only about 10 percent even though in normal engineering practice, initial estimates based on an outline design are only expected to be accurate to within a margin of 15 to 30 percent. Even a 30 percent contingency would have been way off, given the fact that the actual cost will be several hundred percent over the original estimate. While Alcan does now have the experience of Alyeska to draw on, we note that Alcan has included less than a 10 percent contingency allowance in its original $6.7 billion estimate.

The 1960 oil pipeline estimate also omitted the costs of increasing system capacity to 1.2 million barrels per day; greatly underestimated the number of miles of elevated pipeline required; did not anticipate the need to construct a highway bridge across the Yukon River; assumed a system and design which reflected a much lower level of environmental concern than was eventually required, and failed to grasp the magnitude of the support structure such as camps and airstrips that would be required.

INTERIM BUDGET ESTIMATES

From 1969 to May 1974, the cost estimate increased several times to reflect more detailed system definition and design, additions to system size and sophistication, delay costs, and the results of cost estimates prepared by outside companies under contract with Alyeska.

Alyeska did not gear up to develop a detailed comprehensive budget until after May 1974, by which time they had already been granted both Federal and State right-of-way agreements.

We note that Alcan's estimate of costs is growing rapidly. In March 1977, Alcan's budget estimate was $6.7 billion, including interest, in 1975 dollars. Alcan's current estimate is $9.6 billion, including interest. However, Administration officials have stated that their current cost estimate for the Alcan project is between $10.5 billion and $13.7 billion.

Because of inflation, the final costs are likely to be higher than the Administration's $13.7 billion estimate. Further, we believe the estimates are likely to increase significantly, exclusive of inflation, because they are based on minimal site specific data and several important technical uncertainties remain to be overcome.

ALYESKA'S BASE CONTROL BUDGET

Substantial efforts were made by Alyeska, the owner companies, management contractors, and execution contractors in 1974 and early in 1975 to develop a more accurate and detailed budget estimate. A budget control estimate of $6.4 billion, as of April 30, 1975, was ultimately developed as a control mechanism and accepted by the owner companies. The base control estimate was the first estimate supported by firm commitments for nearly all permanent materials and for most of the construction equipment, support services, camps, and other temporary facilities.

The design engineering was about 90 percent complete at this stage, but uncertainties still existed as to soil conditions, labor productivity, and equipment durability and effectiveness. The haul road had been built, and pipeline construction had begun, with the terminal and pump stations being about 5 and 3 percent complete, respectively.

REASONS FOR INCREASE OVER BASE CONTROL BUDGET

As pipeline construction proceeded from 1975 to 1977, the control budget was continually revised upward through hundreds of amendments. By June 1977, the approved control budget had increased to about $7.8 billion, about $1.5 billion, or 23 percent, in excess of the control budget.

About $1 billion of the increase occurred in pipeline construction, the other $0.5 billion increase occurred in terminal and pump station construction. The principal reason for the increase was that 53 percent more direct labor hours (about 20 million hours) were needed to complete the project than estimated. The direct labor hour increase was caused primarily by unexpected site conditions and construction difficulties, worker inefficiency and inexperience, and more winter work than planned.

All these factors were not beyond Alyeska's control. More geotechnical and site-specific work prior to start of construction would have reduced the number of surprises encountered once construction started. For example, unexpected subsurface conditions were encountered at the Valdez Terminal site once excavation was started. This led to much more extensive site preparation work than planned. Also, once ditching operations were started to lay the pipe, it was found that many areas had more groundwater than anticipated. Both of these surpises were costly.

There have been similar patterns of costs spiraling after optimistic estimates in other projects of the same type. It happened in North Sea oil development, for example. A 1975 management study pointed out that many North Sea project developers submitted grossly optimistic initial cost estimates—estimates which made totally inadequate allowances for the cost of overcoming the many problems likely to occur during any large development project. These difficulties are inevitable in untried areas such as the Arctic and the North Sea.

Why do project managers tend to make such unrealistic assessments? The study noted a cluster of beliefs which have widespread industry acceptance:

1. Teams assessing a project's feasibility generally believe that realistically high estimates might result in worthwhile projects being rejected too

early. Since these teams frequently develop a deep personal involvement with a project, they may in fact become promoters rather than objective evaluators.

2. It is also widely held that estimates which start at a low level and then gradually rise over time, are more acceptable than those which are realistic.

3. Furthermore, it is believed that costs will tend to rise to meet any approved estimate or amount of money available.

It is clear that it is in the public interest to insist on realistic initial assessments. The most reliable basis for establishing budget estimates is the development of as much site-specific data as is economically practical. In the case of the gas pipeline, for example, the earlier and more thoroughly that site-specific work can be done, the better will be the project engineering. If project engineering and system design are based on more complete data, both become less subject to change.

PROJECT MANAGEMENT

When Alyeska was organized to engineer, design, and construct the pipeline system, the oil companies retained control of the project through an owner's construction committee. Alyeska top management also consisted primarily of personnel on loan from the owner companies. They met monthly with the committee, which made or approved all major decisions. For instance, the committee made the final decision on selection of the management contractors and construction execution contractors. They also approved the budget control estimate, and had to pass on all construction amendments in excess of $5 million.

A four tier management structure existed. After Alyeska was formed in 1970, the corporation hired two management contractors: Fluor Engineers and Constructors, Inc. in December 1972 for the terminal and pump station construction and Bechtel, Inc. in October 1973 for the pipeline construction. In June 1974, Alyeska contracted with five execution contractors for pipeline construction, while Fluor became the execution contractor for the terminal and pump stations. Alyeska assumed management responsibility for pipeline construction in early 1975.

The primary objective of management was to complete construction at the earliest practicable date in order to start oil flowing on schedule, and to avoid the large costs to the owner companies that would have resulted from construction delays. Construction began on April 29, 1974, with the goal of getting oil flowing in the line 3 years later, by the summer of 1977. The project managers' primary objective was to insure that milestone dates were met. If they were not, this meant hiring more workers, paying for more overtime, and (or) having more work done in the winter, when productivity was lower. The managers from the eight owner companies faced strong internal pressures for quick development.

TYPES OF CONTRACTS

Alyeska's contracts with its management and execution contractors were reimbursable cost plus fixed fee and fixed overhead. The advantage to Alyeska in awarding these reimbursable type contracts was that this form of contract could be negotiated and settled more quickly than fixed-price-type contracts. Alyeska also lacked adequate information on which fixed prices could be negotiated. Contractors would not bid fixed-price-type contracts because there was no definitive design, and other factors such as soil conditions and labor productivity in extremely cold climates were unknown.

Under cost-reimbursement contracts, the contractor has little financial interest in controlling costs because his profits are not affected by the final project costs. Thus, the contractor does not have the same incentive to minimize costs as would exist under other contractual arrangements, such as fixed-price contracts. This type of contract provides the most incentive for efficiency because contractor profits are directly affected by costs. Since fixed price contracts require precise project specifications and detailed design, this is yet another reason why site-specific data should be developed early and thoroughly. We recognize that it is not always possible to enter into this type contract. However, it is desirable to provide the contractor with such incentives to control costs whenever possible.

MANAGEMENT CONTROL SYSTEMS

The management control systems in place when construction began in April 1974 were less than ideal. The systems, including cost control, inventory control, and security programs, had to be changed over the 3-year construction period. For example, Alyeska's cost reporting system initially could not provide up-to-date information on actual costs. The May 1975 budget control estimate was not based on actual outlays because of inconsistent and erroneous coding of costs in 1974 and early 1975. Furthermore, even though Alyeska's first overall pipeline cost report was not published until September 1975, at that late date the report could not use actual costs, since no central computerized system to collect actual costs had been developed. It was not until December 1975—the end of the second construction year—that the cost control system began to function properly.

How a project is going to be managed is clearly important for an adequate assessment of its feasibility. We believe this aspect of the Alcan gas pipeline has been given little attention to date. Although the Federal Power Commission's hearings on the alternative gas line proposals resulted in an impressive volume of information, we noted that most information involved the environmental, technical, and economic merit of each proposal. Only minimal information on details of project management and control systems has been assembled.

Since Alcan probably will be subject to the same internal pressures for quick development as was the case with Alyeska, we believe it is extremely important for Alcan to develop effective management systems early in the planning phase. This will enable Alcan management to develop the information required to exercise better management control over project execution.

NO-STRIKE CLAUSE

Alyeska negotiated an umbrella-type project labor agreement with 16 international unions in late 1973 and early 1974. The agreement was for the duration of construction and included a strong, enforceable no-strike clause with procedures for resolving all types of jurisdictional disputes. It provided for uniform working conditions and adopted Alaska wage rates and contractor contributions to Union benefit funds.

Alyeska's experience shows that the no-strike clause in the labor agreement prevented any section-wide or project-wide strikes. As far as we could determine, there were relatively few work stoppages for a project of this size—76 as best we could determined. On the other hand, there were slowdowns. Although we don't know how many, our discussionns with Alyeska and contractor personnel indicated that slowdowns may have occurred often enough to interfere with productivity. We could not determine the significance of this interference since adequate records were not maintained.

GOVERNMENT INVOLVEMENT

We also examined the impact of government requirements on construction of the Alyeska pipeline. The U.S. Government and the State of Alaska granted Alyeska right-of-way agreements to construct the pipeline on public lands. To protect the public interest in these lands, the agreements contained requirements—many of which were to minimize environmental degradation during construction—with which Alyeska had to comply. To assure that Alyeska did comply, both the State and Federal Governments reviewed Alyeska's system design and construction plans, and monitored construction activities to see that plans were being implemented as approved.

Some disagreements did arise during construction over the meaning of the requirements. Alyeska personnel generally interpreted the requirements less restrictively than governmental personnel.

Because of the differences in interpretations, Alyeska had to make some adjustments to accommodate the government interpretation of the requirement. It was also claimed that the requirements complicated the task of designing and building the pipeline system. However, in response to our requests, Alyeska did not provide any evidence showing where significant construction delays had been caused by this type of problem.

NO ON-GOING AUDIT

The right-of-way agreements granted to Alyeska did not contain any requirement that the government be allowed to conduct an on-going audit during construction to insure that monies expended were prudently incurred and, therefore, were an allowable expense to be included in tariff submissions. As you know, there have been many allegations about mismanagement and monies being improperly spent by Alyeska. The Interstate Commerce Commission is currently conducting an audit to determine which costs should be allowable. Because of the size of the project, this is an extremely difficult task to do within available time constraints.

Because it has proved to be so difficult to post-audit the Alyeska project, we believe a decision should be made now that Alcan's costs will be audited during construction. We believe this would benefit both Alcan and the government. Alcan would not be left in doubt until project completion as to whether its costs would be recoverable through the tariff. The government would be in a far better position to conduct a more effective audit of costs. In this regard, it should be pointed out that no agency of the U.S. Government will have the authority to audit the costs of constructing that portion of the line, about 2,000 miles, that goes through Canada.

These costs in Canada will constitute a significant portion of the total costs of building the pipeline. If they are unrestrained, total costs could increase greatly. We believe the U.S. Government's agreement with the Canadian government should be amended to stipulate that requirements identical to, or at least similar to, those imposed by the U.S.—such as for budgeting, management, and audit controls—will be implemented by Canadian government overseers of the pipeline construction there.

The Federal Power Commission also has recognized the need for an on-going audit during construction of the gas pipeline. The Commission's recommendation to the President dated May 1, 1977, stated that quarterly audits should be established to determine whether costs incurred would be permitted to be recovered through the project's tariff.

We further believe that a clear and specific requirement be established in the agreement to provide the government with direct access to project files and records. At the time of our study, three separate audit groups needed Alyeska data. To respond to these requests, Alyeska hired a law firm to act as liaison. In the interest of obtaining as much information as possible for these hearings, we agreed to this. While we can appreciate Alyeska's need for the arrangement, it caused us procedural difficulties in getting the information necessary to carry on our review, and left us with much uncertainty about the completness and accuracy of the information given in response to our requests.

Before turning to the other important aspects of the proposed gas pipeline project, I will sum up the key lessons to be learned from the Alyeska experience, which we hope, will be applied to the Alcan project.

We should be skeptical of initial and interim cost estimates. Final costs are bound to be significantly higher than these estimates.

We should insist on site-specific data and on thorough investigation of technical and geological uncertainties. This is the only way to avoid unpleasant and costly suprises during development.

Government approval should be contingent on detailed planning for management control including budgetary controls. We believe Alcan should have its managerial house in order before construction is allowed to begin.

We were given no evidence that governmental restraints to minimize environmental degradation created significant complications in Alyeska's construction schedule. This may also prove to be the case with gas pipeline construction.

We should insist on an on-going government audit of the Alcan project's expenditures. This is clear from the difficulties of auditing Alyeska costs after construction was completed.

Our agreement with the Canadian government should be amended to stipulate that an on-going audit and other U.S. requirements affecting the gas pipeline construction will be implemented during construction in Canada.

OTHER ISSUES

I would like to discuss briefly two related issues which are of concern to us. They do not arise as a result of our audit of the Alyeska experience, but stem from concerns we have expressed in other reports dealing with high costs energy supply situations.

First, is the question of government guarantees of the cost of the pipeline. Considerable discussion developed this year over a so-called "all-events" tariff which would amount to a guarantee to return at least debt service and, perhaps, equity should the project not be completed. In essense, such a guarantee would shift the risk from the company to the U.S. taxpayer.

We understand that both Alcan and the Administration now say that there is no needed for such a guarantee. We also see no need for such a guarantee and support the Administration's position. Should the issue arise again, however, we believe careful thought should be given to whether the Federal Government should undertake such risk. There may simply be much more attractive alternatives for government risk-taking than the Alcan pipeline. The government should more thoroughly explore those alternatives before making such commitments.

That brings me to the second point. Any assessment of alternatives should be made on the basis of incremental cost. The cost of Alcan-delivered gas should be compared "at the margin" against other energy supply or demand reducing strategies. This is particularly important since there will be great pressure to "roll-in" the price of Alcan gas when it is delivered to relieve consumers of Alcan gas from a sudden price spike. Whether or not such roll-in should be allowed is a question of equity, which can be decided after further study at a future date. But the actual rolling-in of the price should not be confused with the need to base decisions on whether or not to subsidize Alcan on the true marginal cost of that alternative as compared to others.

In closing, I emphasize that our comments should not be construed as taking a GAO position either for or against the eventual construction of the Alcan project. Rather, we believe the final project cost cannot be realistically estimated until more site-specific data are obtained, the technological problems solved, the project substantially designed and engineered, and a base control budget established. We expect the current project estimates will be revised upward.

That concludes my statement, Mr. Chairman. I will be happy to answer any questions.

Senator McClure. Thank you. On page 7 of your statement, you refer to the difficulties of making estimates and the surprises—you outline two surprises that Alyeska encountered. You point out that both surprises were costly. In the beginning of that paragraph you said: "All these factors were not beyond Alyeska's control."

I suspect what you really mean there, rather than control is expectation.

Mr. Canfield. Anticipation would be a better word.

Senator McClure. These were not controllable factors, but these two that you mentioned might have been anticipated and might possibly need to be anticipated in the Alcan project.

Mr. Canfield. That's the critical point. We found it was absolutely crucial to have a better understanding of the underlying geography and site-specific information in order to have been able to budget these things appropriately.

Senator McClure. What seems to be implicit in most of the discussions, the expectations that regardless of cost, the energy to be produced will be less expensive than alternatives.

You are at least questioning that premise.

Mr. Canfield. You have to question the premise, Mr. Chairman. It seems to me obvious that if we really don't know what the Alcan pipeline is going to cost, and the estimates already have ranged from a little over $6 billion in April of this year to a Government operating-level estimate of twice that, a little over $13 billion, and we are not at all convinced that that estimate is anywhere near where it's going to come out, each one of those increases add to the cost of that alternative.

And when you start to compare it against other alternatives, it is difficult if not impossible to figure out which alternative is more economical.

Senator McClure. When you are speaking of other alternatives, you are not speaking of other alternative pipelines but other alternatives to meeting the goals of energy self-sufficiency in this country.

Mr. CANFIELD. That's right, we are referring to developing an equitable supply-and-demand balance of energy in this country which could come from other natural gas sources, or could come from demand reduction, or any number of technological solutions we have waiting for us on the shelf.

Senator McCLURE. I guess one of the other things that has to be considered in that formulation also has to be the time frame of those alternative solutions, as well as the time frame for this one.

Mr. CANFIELD. Absolutely, and that brings me to the same point that you were raising earlier. There is going to be considerable pressure once this thing starts to bring this thing on line, in order to make it as profitable as possible as quickly as possible, and to bring it to where the customers are.

Senator McCLURE. You make the point that you don't believe that Government guarantees will be necessary in terms of the all-events tariffs. You think, as I gather it, that the some-events tariff, as Dr. Schlesinger described it, is a sufficient arrangement to make financing available.

Mr. CANFIELD. We have not studied that in detail; I don't know whether it is a sufficient arrangement or not. What we were trying to say, in essence, was that an all-events tariff should not be necessary.

We were trying to say that if an all-events tariff were necessary, we have a lot more thinking to do.

Senator McCLURE. I have some doubts in my own mind whether financing can be arranged, if the producers do not participate and if there is not some kind of guarantee. I may be mistaken in that, but I am impressed by the evidence that has been presented to this committee.

There has to be a broader base of security than just the financing and the equity and the pipeline itself.

On page 15 of your statement, and I think repeated later also in the statement, you have set forth your belief that the agreement with Canada should be amended to stipulate that the budgeting management audit controls imposed on Alcan by the U.S. Government would also be applied by the Canadian Government to the pipeline construction within its territory.

Do you recommend that without such an amendment the Congress should disapprove the agreements?

Mr. CANFIELD. I don't think I would go that far. I think with 2,000 miles of it going through Canada, it strikes me—let's take something like current auditing. If they are not auditing that project on a day-by-day basis, they are not going to be able to understand how much is going to be spent, what the management controls are, and what the budgetary controls are.

I think if we don't have a very firm understanding of how much oversight we are going to get from the Canadian Government, we could find ourselves in a real pickle down the road.

I would not want to say that we would want to stop everything, but it strikes me that some sort of an understanding should exist between the United States and Canada, that they will as diligently monitor and audit this pipeline as we will.

It is very, very crucial to the success of the pipeline. Otherwise, the costs would be borne by the American consumer.

Senator McClure. Has the GAO looked at the question of guaranteeing against future price increases caused by governmental actions of the Government of Canada or the Provinces?

Mr. Canfield. Not specifically; no, sir, we have not.

Senator McClure. I remain concerned with that question that I do not think that the assurances I got from Dr. Schlesinger are sufficient to remove that concern from my mind.

That the agreements that have been presented to us do not necessarily guarantee that there will not be inequitable treatment of the cost of the gas as delivered to the American consumer. If you have any studies, or if without going to inordinate work you could supply us with any conclusions on that subject, I would appreciate your furnishing it for the record.

Mr. Canfield. Why don't we study the proposal a little more carefully in that light, and see if we can come forward with a brief white paper in a short period of time for you.

Senator McClure. I think that would be very helpful, and I would appreciate it. [Not received.]

Thank you, very much, Mr. Canfield.

Mr. Canfield. Thank you.

Senator McClure. All right, the committee will stand adjourned until 10 o'clock tomorrow morning.

[Whereupon, at 12:20 p.m., the committee recessed, to reconvene at 8 a.m., Tuesday, September 27, 1977.]

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

TUESDAY, SEPTEMBER 27, 1977

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 8 a.m., in room 3110, Dirksen Office Building, Hon. Clifford P. Hansen presiding.

Present: Senators Hansen, Jackson, and Ford.

Also present: Betsy Moler, counsel; and George Dowd, counsel.

OPENING STATEMENT OF HON. CLIFFORD P. HANSEN, A U.S. SENATOR FROM THE STATE OF WYOMING

Senator HANSEN. The hearing will be in order.

This is the second day of information on the President's decision to designate the Alcan pipeline project for approval pursuant to the Alaska Natural Gas Transportation Act of 1976.

Yesterday, the committee received information from Dr. Schlesinger and from Monte Canfield. Today, our first witness will be the distinguished senior Senator from Indiana, Mr. Bayh.

STATEMENT OF HON. BIRCH BAYH, A U.S. SENATOR FROM THE STATE OF INDIANA; ACCOMPANIED BY EVE LUBALIN OF HIS STAFF

Senator BAYH. Thank you, Mr. Chairman. If you have no objection, I would like to ask Ms. Eve Lubalin of my staff——

Senator HANSEN. Without objection, we are pleased to have you here.

Senator BAYH [continuing]. To join these hearings.

I want to express my deep appreciation to you for not only your normal hospitality and cooperative nature in helping to move the legislative process and accommodate other Senators, but also for being here at this early hour. Indeed, Cliff Hansen's normal tendencies have been stretched that extra mile by his presence here this morning and I am very grateful.

Mr. Chairman, we are here, of course, to carry on at the committee stage the discussion in which this committee has been actively involved—the discussion of better meeting this country's energy needs.

There are, in the Senate, some very strong differences of opinion on these matters. I see my distinguished friend from Alaska here, for whom I have the greatest respect, but I suspect he and I have differing opinions on the issue which brings us here today.

But despite these differences I think all of us are determined to do what we can to ultimately resolve our problems and try to represent our constituencies the very best we can and, in the final analysis, to do what is in the national interest.

In a country as diverse as the United States of America, with institutions set up to represent our differences, Senators will naturally come to varying conclusions and hopefully this committee and the Senate can iron these out and come up with what is in the national interest.

I might suggest, Mr. Chairman, that the quickest way for me to proceed, is to read a statement that I have. I have the normal senatorial tendency to take twice as long to summarize a statement as to read it.

Senator HANSEN. Whatever manner you wish to proceed in, Senator Bayh.

Senator BAYH. I ask unanimous consent to put the first page and a half into the record and just move on to page 2.

Senator HANSEN. Hearing no objections, so ordered.

Senator BAYH. Mr. Chairman, these hearings could not be more timely. As we are all aware, the Senate has spent much of its time during the last week debating the crucial issue of how to assure that American towns and cities, and farms and factories will not again suffer the hardships and dislocations experienced last winter as a result of natural gas shortages.

Natural gas is a critical component of the Nation's total energy supply, making up about one-third of all energy used in this country. Although many of us have differed about the best way to provide ourselves an adequate supply of natural gas as we gradually move toward use of alternative and more plentiful fuels, all of us agree that we must do every thing possible to reduce the probability of continued gas curtailments in the winters ahead. One critical factor in giving us this assurance will be prompt access to our Alaskan gas and continued exports of Canadian gas until we can manage comfortably without it.

Recognizing the need to act quickly to build a transportation system to bring our Alaskan gas south, last year the Congress passed the Alaska Natural Gas Transportation Act which established special procedures for selecting an Alaska gas transportation system. At the time we passed the act, there were three competing systems proposals. The exhaustive selection procedures prescribed by the act, as well as those undertaken by the Canadian Government, have clearly indicated Alcan's superiority. Alcan's two competitors—Arctic Gas and El Paso—have voluntarily withdrawn as a result of this extensive scrutiny and the strong support for Alcan evident within the executive and legislative branches of Government.

Early this month, the President formally recommended the Alcan route to the Congress. Responsibility for prompt action, which will permit a quick start on construction, now rests with those of us who sit in Congress for we must, as you know, Mr. Chairman, confirm the President's decision before it can be implemented.

I certainly hope that this committee and the Senate as a whole will move rapidly to approve the President's decision.

It seems to me, Mr. Chairman, after a great deal of discussion, analysis and debate and, taking into consideration the need to distribute Alaskan gas equitably, and to areas such as the one I come from which is short of energy, that President Carter's choice of the Alcan proposal reflects its superiority in almost every respect.

It has lower cost of service for delivery of Alaskan gas and it can deliver this gas at the earliest date. It has a special provision to provide new volumes of Canadian gas at an even earlier stage. It also offers the possibility of continued Canadian gas exports to this country, if the Canadian Government decides to go ahead and build the Dempster lateral.

The Alcan proposal has clear-cut environmental superiority. The private financing system proposed by Alcan is freer of Government influence than others have proposed. The direct pipeline delivery of Alaskan gas to regions both east and west of the Rocky Mountains is, I think, an equitable system and will prevent the kind of problems we now have with Alaskan oil.

Alcan's pipeline system also has a high degree of safety and reliability and provides significant savings in the amount of gas that will be required as fuel for the transportation system.

I will not go into these advantages in depth. This committee will, I understand, have other witnesses before it who will describe, in greater detail, some of the strong pluses that the Alcan route represents. I am sure my distinguished friend from Alaska will address these points and perhaps come to a different assessment.

If the Chair has no objection, I would like to introduce into the record a fact sheet which I have circulated to every Senator, which describes Alcan's advantages in some detail, and not belabor the committee with that.

Senator HANSEN. Without objection, it will be received.

[The fact sheet referred to follows:]

FACT SHEET ON THE ALCAN NATURAL GAS PIPELINE PROJECT

On September 8, the President announced his selection of the Alcan system to transport natural gas from Alaska's North Slope to the lower 48 states. Under the provisions of the Alaska Natural Gas Transportation Act of 1976, Congress has the responsibility for approving this decision by joint resolution within 60 calendar days.

The President's decision on a transportation system for Alaska natural gas required a choice between two radically different alternatives. Originally, three major proposals for transporting Alaska gas—those advanced by Arctic Gas, Alcan and El Paso—were submitted to the Federal Power Commission. One of these, Arctic Gas' proposal to bring gas across the Arctic National Wildlife Range and then down Canada's Mackenzie Valley, was eliminated by environmental objections and decisions of the Canadian government. Significantly, the U.S. Artic Gas sponsors then decided to support Alcan due to their belief that Alcan promises the earliest and lowest cost delivery, the fewest adverse environmental consequences, and the possibility of access to Canadian frontier reserves.

The second, the Alcan system selected by the President, will be an all-pipeline system which will parallel the Alyeska oil pipeline from Prudhoe Bay, Alaska to Delta Junction, which is near Fairbanks. From there, it will follow the Alcan highway into Canada and existing transportation corridors to the U.S. border. Canada will be able, at a future date, to connect its Mackenzie Delta reserves to this system by a new pipeline known as the Dempster link.

The Alcan system includes western and eastern legs in the lower 48. The western leg will deliver gas to the states of the Far West while the eastern leg will carry gas directly to the Midwest, from where it can be transported to the East. Thus, Alcan satisfies the requirement, which the Congress imposed last year, for direct delivery of Alaska gas both east and west of the Rocky Mountains.

In the third proposal, El Paso advanced a combined pipeline-liquefied natural gas (LNG) system. The El Paso pipeline would follow the Aleyska line to Alaska's south coast. The gas would be liquefied there and then shipped by cryogenic (super cooled) supertanker to California, where it would have to undergo a regasification process.

The President's decision is a reflection of Alcan's superiority over the competing El Paso proposal in almost every respect. This fact sheet lays out the relevant considerations concerning the most critical factors involved in the selection of the Alaska natural gas transportation system.

COST OF SERVICE

The cost of service, which includes all operating charges and annualized capital costs, measures the cost of transporting gas.

Alcan has a clear advantage in cost of service for Alaska gas, which is the most important factor in system selection. The Administration's estimate as to Alcan's 20 year average cost of service, which includes an allowance for substantial cost overruns, is $1.03 to $1.05 per million BTU's (MMBtu) in 1975 dollars. Alcan's own estimates as to cost of service are significantly lower, but even if the higher estimates for Alcan are used, El Paso's cost of service would be 16 percent greater. The Administration's estimates as to El Paso's cost of service is $1.19 to $1.21 per MMBtu in 1975 dollars.

Similarly, the Federal Power Commission and the Federal government task force which commented to the President on July 1 found that Alcan would be the less expensive means of transporting Alaska gas. The FPC's cost estimates were 79 cents per MMBtu for Alcan and $1.09 for El Paso; the task force's estimates were $1.09 per MMBtu for Alcan and $1.26 per MMBtu for El Paso.

If escalated costs—the costs that will actually be incurred at the time the project is built—are used, Alcan's cost of service advantage becomes even greater. This results from the greater labor intensiveness of the EL Paso project which causes El Paso's construction costs to increase with inflation faster than Alcan's.

EARLY DELIVERABILITY

Alcan offers important advantages with respect to early deliverability, which is critical for alleviating the existing natural gas shortage.

If the Alcan project is approved soon, we will likely begin receiving additional volumes of Canadian gas during the winter of 1979–80 and Alaska gas in the winter of 1982–83. The 1979–80 delivery date is possible because Alcan has already contracted for additional Canadian gas from Alberta for delivery to the lower 48. The Canadian government has indicated that this gas can be sold to the United States and that it will permit the prompt start of construction of the southern end of the pipeline system. Thus, additional Canadian gas can be distributed to the lower 48 by the winter of 1979–80 and these deliveries can be continued until completion of the entire pipeline system for bringing our own Alaska gas south. Additional amounts of Canadian gas delivered through the southern part of the Alcan pipeline could amount to as many as 800 million cubic feet per day.

By contrast, El Paso's presently predicted completion date is 1984. Thus, Alcan will be able to deliver additional volumes of Canadian gas and our own Alaska gas long before the El Paso system could become operational.

CONTINUED CANADIAN GAS EXPORTS

Only Alcan offers the possibility of continued Canadian exports of natural gas to the United States in the coming decade. Canada now supplies some 5 percent—2.7 billion cubic feet per day—of U.S. gas consumption. These Canadian exports are greater than the 2.4 bcf per day of new Alaska gas flows that will be available through the proposed transportation system. Further, in some areas, Canadian exports constitute a sizable portion of total supplies—for example, 65 percent in Washington and Idaho, and 45 percent in Oregon and California.

Canada's National Energy Board has indicated that indefinite continuation of these exports would require the curtailment of domestic Canadian consumer deliveries. In order to avoid such curtailments, exports to the U.S. may have to be cut back as early as 1982 or 1983 and completely stopped by 1989, which would have a devastating effect. The most effective means to avoid such cutbacks in the early 1980's is for the United States to facilitate Canadian access to its frontier reserves. If Canada is able to utilize these presently inaccessible reserves, it will be better able to continue exports to the United States and supply its own domestic needs. The Alcan route will facilitate such access, thus substantially decreasing the possibility of cutbacks of exports to the U.S.

The El Paso system could not assure the continuance of exports from Canada since it would not affect the accessibility of any of the Canadian frontier reserves. Thus, selection of the El Paso system could lead to an actual reduction in gas supplied to the lower 48; the 2.4 bcf per day of Alaska gas would be more than offset by the loss of 2.7 bcf per day of Canadian gas.

ENVIRONMENTAL CONSIDERATIONS

In addition to greater economic benefits, the Alcan project is environmentally preferable. Thus, this decision does not require the normal trade-off of environmental preferences against higher costs. By utilizing an all-pipeline system which largely follows existing corridors, Alcan assures minimal disruption of the environment.

By contrast, El Paso will create significant environmental impacts, primarily from the liquefaction and vaporization facilities which are not required for an all pipeline system.

The facilities which would be needed in Alaska to liquefy the gas would be located at Gravina Point in one of the greatest areas of seismic hazard in the world. As the Federal Power Commission noted, El Paso has not provided sufficient information to determine whether a seismically safe system has been developed.

Further, the Alaska liquefaction facility would discharge large quantities of heated water into Prince William Sound, thus threatening aquatic life. The FPC concluded, its recommendation to the President, that "an acceptable solution to the heat discharge problem for the El Paso proposal has not been proposed."

Enormous siting problems are presented by the California vaporization, or regasification, facility. The California legislation has been considering two bills for expedited LNG terminal siting. A compromise has reportedly been worked out whereby the plant which will benefit from the expedited siting procedure will have to be located at a remote coastal site. The only presently acceptable site is Point Conception, which El Paso has sought to utilize for Prudhoe Bay gas. However, the compromise legislation limits the facility to a size which would only accommodate LNG under contract from Indonesia and Alaska's Cook Inlet. Thus, the El Paso project is effectively prevented from utilizing the expedited siting procedure. At the least, this will substantially delay the El Paso project; further, it creates substantial uncertainty as to whether California will permit any onshore LNG terminal for the El Paso project. Major environmental questions will therefore have to be resolved in deciding this siting issue.

In addition to the imports from the liquefaction and vaporization facilities, the El Paso proposal would affect the Chugach National Forest, a de facto wilderness area on Alaska's southern coast. El Paso would have to construct a large liquefaction facility and approximately 43 miles of pipeline across previously undisturbed terrain. The impact of this construction and of consequential development would be significant.

Alcan's environmental superiority has been recognized by all agencies and interested parties which have reviewed the Alaska gas transportation proposals. The Council on Environmental Quality, in its report to the President, found that Alcan "is the most environmentally acceptable" proposal while the El Paso alternative "presents risks to the environment, public safety and to system integrity not present in the overland corridors." Indeed, the Council on Environmental Quality concluded that there was not enough information to determine whether the El Paso proposal was environmentally acceptable. Similarly, the Interagency Task Force on Environmental Issues reported to the President that Alcan's route appears to promise the least environmental impact.

Other agencies and groups have reached the same conclusion. The Federal Power Commission unequivocally found that the "Alcan route promises the least environmental impacts . . ." The Conservation Intervenors in the FPC proceedings (the Sierra Club, the Wilderness Society, the National Audubon Society and the Alaska Conservation Society), stated that ". . . if a pipeline must be built, the public interest would be best served by an all-overland pipeline system that follows the Alyeska Oil Pipeline, the Alcan Highway and other existing utility corridors in Canada." Finally the Canadian agencies which have examined the Alcan proposal—the National Energy Board, the Berger Commission, and the Hill Inquiry—have all concluded that Alcan's environmental impacts in Canada are acceptable.

CAPITAL COSTS

Alcan has estimated that its capital costs, including both eastern and western legs, will be $7.6 billion in 1975 dollars. The Administration's estimate, which includes provisions for substantial cost overruns, is $8.8 billion. These figures include a portion of the estimated costs of a segment of the "Dempster link" between Dawson and Whitehorse, which will be built sometime in the future to allow Canada to access her frontier Mackenzie Delta reserves. As is discussed below, the U.S. will not provide the investment capital when this segment is constructed, but will pay a portion of the annual cost of service when operations commence.

The Dempster link will be a separate Canadian project and it is not appropriate to consider any other part of its costs as part of Alcan's capital costs. Indeed, when the Dempster link connects Canada's Mackenzie Delta gas reserves to the Alcan system and Canadian gas begins to flow through Alcan, a portion of the costs of the joint project will be allocated to the users of the Canadian gas, thus reducing the capital costs of the Alaska gas transportation system.

El Paso has estimated its capital costs to be $6.6 billion in 1975 dollars and the Administration's estimate is $7.6 billion but the figures may be unrealistically low. First, El Paso has assumed that it can construct the necessary facilities to accomplish its complex displacement plan for $400 million. However, the Mexican government has recently announced that it will be selling large amounts of Mexican gas to the United States. These volumes of Mexican gas will take up existing excess capacity in pipelines delivering gas to the east. Therefore, additional facilities and additional capital costs will be required to transport Alaska gas from the west coast of the United States to those areas of the country which need it.

El Paso's capital costs are also based on optimistic assumptions with respect to the construction of a liquefaction plant at Gravina Point, Alaska and a vaporization plant in California. The development of a seismically safe design and of an adequate water cooling system to avoid pollution in Prince William Sound may well require a substantial increase in presently projected investment. The uncertainties surrounding the location of the vaporization plant in California make judgements as to the validity of the estimated capital costs for that facility quite difficult. However, it is clear that if an offshore facility is required, substantial increases in capital costs, as well as extensive delays, will result.

FINANCING

The Alcan project can be privately financed without U.S. or Canadian government guarantees. The same cannot be said of the El Paso project since it would, at the very least, require substantial taxpayer support in the form of U.S. government guaranteed financing of the proposed tanker fleet. In addition, El Paso has proposed an "all events" tariff or rate structure. Under this type of tariff, the consumer would bear all or a part of the credit risks stemming from the possibility that the project would not be completed or that gas deliveries would be interrupted for an extended period of time.

The President's decision requires the Alcan project to be privately financed in its entirety: neither the U.S. or Canadian governments nor the consumer will be called upon to provide financial guarantees. The financial backing will come from the other primary beneficiaries of the project, such as, the gas transmission companies, the State of Alaska, and the gas producers. Alcan will have to demonstrate that acceptable provisions have been made against the risk of noncompletion before construction can begin. The return on the equity invested in the system will be based upon a variable rate of return designed to provide incentives to avoid cost overruns and minimize costs consistent with sound pipeline management.

Finally, it is clear that Alcan can obtain the necessary project financing from Canadian and U.S. sources. Alcan's present financing plans will require Canadian bank loans of $510 million and Canadian long term debt of $419 million. These amounts are well within the capacity of each of these Canadian capital markets. Similarly, demands on U.S. capital markets will not be beyond the capacity of those markets.

DIRECT DELIVERY VERSUS DISPLACEMENT

Alcan proposes direct delivery by pipeline to the areas of the country in need of additional natural gas. El Paso proposes to ship the Alaska gas to the west coast, where it is not needed. El Paso would then move it by a complex displacement scheme from the Los Angeles area on the far edge of the nation's gas transmission system to the remainder of the nation. Displacement has never before been attempted nor relied upon on such a massive scale.

Displacement, the delivery of gas for transportation at one location and the redelivery of an equivalent amount of gas at another location, creates physical, contractual and regulatory complexities which increase as more companies and greater distances are involved. Even less massive displacement efforts than those proposed by El Paso have not succeeded. For example, during the emergency gas shortage last winter, shippers in the western U.S. made gas available to eastern shippers through displacement. Although significant volumes of gas were delivered in this fashion, additional volumes of gas which were desperately needed in the east and available in the west could not be delivered because of facility limitations.

In addition, El Paso's difficulties with displacement have been exacerbated by the Mexican government's recent announcement of its intent to sell major volumes of Mexican gas to U.S. shippers. Initial deliveries of Mexican gas to the United States will commence in 1979 and will utilize the presently existing excess capacity in the South Texas pipelines. Thus, El Paso will not be able to utilize this existing excess capacity, as it had previously planned, with the result that additional facilities and greater delivery costs for displaced Alaskan gas will be required.

In sum, displacement is an inadequate means for delivering gas over long distances and is an unsatisfactory basis for long term delivery of Alaska gas reserves.

WESTERN LEG

The President's decision provides for a full western leg for the Alcan system, which will transport Alaska gas directly to the states of the Far West. The western leg will run from the Canandian border to Antioch, California, near San Francisco. Its exact capacity will be determined at a later date but in time for the western leg to be operational when the main line comes on stream. Parts of the western leg will be built early to permit additional volumes of Canadian gas for which Alcan has already contracted to be shipped to the far west.

Authorization of the western leg will assure equitable distribution of the Alaska gas and of the additional volumes of Canadian gas. This will enable all regions of the country to share in this new source of gas; no region will be forced to rely on older sources whose declined production may not provide an adequate long-term supply.

SAFETY AND RELIABILITY

As both the Federal Power Commission and the Administration have noted, an all-pipeline system such as Alcan, is inherently more reliable than an LNG system. The complexity of the liquefaction and regasification facilities and tanker shipments—all of which are required for an LNG system—create a substantial probability of service interruption. Indeed, Western LNG, the sponsor of El Paso's California regasification facilities, has urged that two or more facilities be constructed because of "the very real possibility of an event which could cause the plant to shut down."

An LNG system also presents significant public safety risks. Although El Paso has vigorously asserted the safety of its system, the Council on Environmental Quality concluded that the "analyses of LNG public safety risks on the record are inconclusive." This contrasts with the established safety record of natural gas pipelines.

ENERGY EFFICIENCY

When both Alaska and Canadian gas are flowing, the Alcan system will deliver 92.1 percent of the Alaska gas entering the system. El Paso will be able to deliver only 89.1 percent. The difference is 600 trillion Btu's (600 billion cubic feet) over the first 20 years. The annual savings—30 billion cubic feet—would be sufficient to heat over 245,000 homes.

EMPLOYMENT IMPACTS

El Paso has claimed that its project will create many more jobs than will Alcan. Specifically, it has asserted that it would create 730,000 person-years of employment in comparison to only 235,000 person-years for Alcan. However, the Federal Agency Task Force on National Economic Impact reported to the President that the relative difference between the two systems is considerably smaller. It found that El Paso would provide 271,000 person-years of employment while Alcan would provide 240,000 person-years. Although El Paso will provide more employment for Americans, the difference is not nearly as significant as El Paso suggests.

CANADIAN ISSUES

The Canadian aspects of the Alcan system have been the subject of a number of arguments that Canada would exert improper control over the pipeline system or impose discriminatory taxes of it. These arguments are simply not supported by the facts.

In the first place, there is nothing in the history of U.S. Canadian relations that would indicate the likelihood of such action by the Canadian government. Alcan will improve these relations; as Energy Secretary Schlesinger has noted, the Alcan system will be "mutually beneficial to the two countries and . . . the start of a new era in Canadian-American relationships." Second, as a practical matter, Canada has no incentive to take such action since a substantial portion of its oil and gas cross the U.S. by pipeline. Finally, the recent U.S.-Canadian Treaty on Transit Pipelines and Agreement in Principle on the Alcan project negotiated last month will ensure that Canada does not exercise improper control or impose discriminatory taxes.

TRANSIT PIPELINE TREATY

This treaty, which was ratified by the Senate in August, applies to all hydrocarbon pipelines of one signatory that cross the territory of the other signatory. It establishes, as a matter of treaty law, the principle that each signatory shall treat the pipelines of the other in a non-discriminatory manner.

AGREEMENT IN PRINCIPLE

Following ratification of the Transit Pipeline Treaty, representatives of the Canadian and American governments engaged in extensive negotiations concerning the Alcan project. The result of these negotiations was a Agreement in Principle between the U.S. and Canada which applies the Treaty's general principle of non-discrimination to the Alcan project and also resolves other key issues concerning the project. The basic components of this agreement include:

Routing.—In July, Canada's National Energy Board recommended a realignment of the Alcan route so that it would pass through Dawson, Yukon Territory in order to facilitate Canadian access of her frontier gas resources through construction of a "Dempster Link" from Dawson to the Mackenzie Delta. As a result of the inter-governmental negotiations, the realignment was dropped. The pipeline in Canada will follow the original Alcan highway route.

In exchange for Canada's agreement not to require this route diversion, the Agreement provides that the U.S. portion of the project will pay between two-thirds and 100 percent of the costs of service of the segment of the Dempster link originally recommended by the Canadian Energy Board. The exact share of these U.S. costs for this small segment of the Dempster link will be determined by the cost overruns on Alcan construction in Canada. The lower the cost overruns on the Alcan system, the higher the U.S. portion's share of the cost of this segment. This cost sharing agreement creates new incentives—on a portion of the project within Canada's jurisdiction and not otherwise subject to U.S. control—which could significantly lower the cost of service to the U.S. *and* enhance the project's financibility.

System Efficiency.—A higher capacity pipeline system than was proposed by Alcan will be installed south of Whitehorse, the point at which the Dempster link from the Mackenzie Delta will connect with Alcan. A joint testing program will evaluate the technical feasibility, safety and reliability of alternatives to the proposed 1260 p.s.i. 48-inch design in order to permit transportation of higher volumes of Alaska and Canadian gas.

Cost Sharing.—For that part of the pipeline in Canada through which both Alaska and Canadian gas will flow, cost of service will be allocated in proportion to the volumes of gas transported for each country. This will enable the cost of service for Alaska gas to be reduced and will benefit both countries.

Taxation and Other Costs.—Canada's NEB also proposed that a special fund for indirect socio-economic costs of pipeline construction in the Yukon be established. As a result of the intergovernmental negotiations, it was decided that these costs will be paid out of tax revenues, which will be determined in accordance with mutually-agreed upon rules. The Agreement in Principle provides that the Yukon Territory property tax will be levied at the same rate as the property tax in Alaska. This tax will be subject to a fixed ceiling of $30 million Canadian annually (as adjusted for inflation).

Such an approach is appropriate since it embodies the principle that the costs of a project should be borne by its beneficiaries. In recent years, the U.S. has come to realize that large construction projects create major secondary effects and has taken steps to compensate those who are adversely affected. Examples are the Coastal Zone Management Act Amendment, the Strip Mining Act, and the OCS bill recently passed by the Senate.

Other charges will include only those direct costs normally paid by pipelines, such as highway maintenance caused by the moving of heavy equipment.

MUTUAL BENEFITS

The joint pipeline project has a number of advantages over alternatives which were considered by each country. The advantages to the U.S. have been described above and include such factors as lower costs, environmental superiority, and earlier gas delivery. Advantages to Canada include lower costs of transporting Mackenzie Delta reserves, the ability to phase development and construction, and additional time to prepare for the social impacts of pipeline access to the Mackenzie Delta.

NATIVE CLAIMS

A final Canadian issue, the native claims dispute in the Yukon, deserves brief mention. It has been erroneously asserted that Canada will attempt to force U.S. consumers to pay the cost of settling this dispute and that the settlement would delay pipeline construction by three to four years.

The Canadian Government, however, has informed the United States that it regards the settlement of the Yukon native claims as an exclusive Canadian responsibility and that no charges related to the settlement of such claims will be levied against the pipeline.

The arguments as to a three to four year construction delay arise from a misunderstanding of the Lysyk Inquiry report to the Canadian government on native claims issues in the Yukon. This report recommended a four year moratorium on pipeline construction, beginning August 1, 1977. The Canadian government has since reduced the moratorium period to 3½ years and has clearly indicated that it does not apply to preconstruction activities so that Alcan will be able to undertake all steps except actual construction during the moratorium. Thus, Alaska gas will begin to flow January 1, 1983. Further, this moratorium will not affect earlier deliveries of additional Canadian gas, which has already been contracted for by Alcan.

POTENTIAL DELAYS IN CONSTRUCTION OF THE EL PASO SYSTEM

Any potential minor delay in constructing the Yukon segment of the Alcan system must be compared to several potentially serious sources of delay for the El Paso proposal. The most serious results from the controversy surrounding siting of the California vaporization facility. As discovered above, the bill now under consideration in the California legislation would not enable El Paso to benefit from an expedited siting procedure. In addition, this legislation creates substantial uncertainty as to whether California will permit any onshore LNG terminal for the El Paso project. If an offshore location is required, delays of as much as 8 to 10 years might result since the necessary technology for an offshore facility is not yet available.

Should this legislation not be enacted, lengthy delays are still likely. The onshore locations that are being considered would require a choice between concerns for public safety and the environment. In addition, the sponsor of the California vaporization facilities has indicated that two such facilities will be necessary despite California law which provides that only one such facility can be sited in California. Resolution of this controversy could take time and lead to extensive delays even under existing law.

Another potential source of delay concerns the design of the Gravina Point liquefaction facility. The Federal Power Commission found that El Paso has not yet proved that it can design a seismically safe liquefaction facility for this location. Further, the problem of heated water discharges has not been solved. Resolution of these problems will not be easy and could significantly add to the time required for completion of this facility.

No LNG project anywhere near the size of that proposed by El Paso has ever been attempted. The massive scaling up of complex technology required by the much larger El Paso proposal could also lead to delays. Finally, implementation of El Paso's proposed displacement scheme could be a further source of delay, particularly in view of the changes necessitated by imports of gas from Mexico.

Senator BAYH. I would like to take this opportunity to comment on two particular points this morning, Mr. Chairman, the project's financing and the possibility of continuing Canadian exports of gas to the United States as well as to make clear the importance of quick congressional action.

The President's decision specifies that the Alcan project will be financed without any Federal Government or consumer guarantees. The administration envisions that the equity funds for the project will be provided by gas transmission and distribution companies.

Both Alcan and the administration anticipate that the necessary equity and debt can be raised because of the economic desirability of Alaska gas and the reliability of the Alcan transportation system.

Nonetheless, the President's report does indicate that because of the possible cost overruns associated with a project of this magnitude and character, it may be necessary for some sort of cost overrun guarantees to be extended to creditors to assure them that overruns will not lead to abandonment of the project.

I think what the President is anticipating and what I think we should anticipate, Mr. Chairman, is an insurance policy. This insurance policy is necessary to guarantee that the original financing will be available.

There are, in my opinion, two appropriate sources of such guarantees, the producers of Alaskan gas and the State of Alaska, both of whom will benefit enormously from this project. The only alternatives to these two parties guaranteeing against these risks is for the Federal Government or gas consumers to take up the financial burden.

The State of Alaska and the major producers have previously indicated that they are not inclined to guarantee the Alcan project and I think it is extremely important to take a few moments to indicate why it is more appropriate for these parties to guarantee financing assistance than for either the Federal Government or American consumers to do so.

Alaskan gas producers stand to profit handsomely from their large gas reserves in Alaska once a transportation system is in place. In his testimony yesterday, Secretary Schlesinger indicated that the major Alaskan producers expect approximately $20 to $25 billion in profits from the gas sales that the Alcan project will make possible.

It seems to me that asking them to assist in financing the project is reasonable and equitable in light of their vast financial resources and the profits they will realize as a result of the project.

Let me emphasize, Mr. Chairman, that my first preference would be to have the project carry itself. However, given the scope of this project, the desire of creditors for an auxiliary fallback finance system is understandable, and here it seems fair to place the risk on those who will ultimately reap the profits.

For that reason, I think the producers are the first parties to which we should direct our attention. They are in the gas business to make money and indeed, it seems to me they ought to share some of the burden in the event we need financial guarantees.

I want to say that although I would prefer that producers bear this primary responsibility, I think the same logic can be applied to the State of Alaska, which would receive up to $7½ billion in revenue from royalties and severance taxes.

In addition, if this pipeline is built, the State will receive other substantial benefits, including $50 million per year in property taxes. Given this benefit, it seems to me that asking the State to assist financially is not unreasonable.

Here again, I would hope that the State of Alaska is not needed as a contributor to any auxiliary financing plan. But, in assessing who should bear the burden, if there is a necessity for a backup financing mechanism, it seems reasonable to direct our attention to those who will profit most.

Senator HANSEN. If I might interrupt there, Senator Bayh, let me ask you this. It is my understanding that unlike the situation in the United States, in Canada, the Provinces there, not the Northwest Territory but the Provinces have far greater autonomy in deciding what may be done insofar as natural resources are concerned as is true in the United States.

Supposing that just part of the delay that was experienced in the construction of the Alyeska pipeline were to be reexperienced in the building of this pipeline across Canada and in the meantime, we had a continuance of the inflationary experiences we have had in the past.

Do you anticipate that this overrun could be a rather sizable amount?

Senator BAYH. Well, cost estimates included in the President's report anticipate significant cost overruns. If one compares the President's figures with Alcan figures, there is a significant built-in fudge factor there.

I don't anticipate significant delays because of the provinces. A good deal of progress has been made in resolving the Natives claim problem in the Yukon Territory. This issue would have been much more difficult if the northern Arctic route had been selected.

I think it is important to nail down the extent of Provincial authority with an inter-Provincial agreement and I understand the Ottawa Government has assurances from the Provinces on that now. I would rest more easily if they would follow up on these assurances with the incumbent Provincial governments to protect us and the Canadian Government from a change of Provincial governments later on.

I would hope that the administration is pursuing that now that the initial negotiations are over.

Senator HANSEN. You made a statement that you would hope that the State of Alaska would join with the producers of natural gas, as I understand you to say, in giving the backup insurance necessary to assure completion of the line by providing the additional financing. Am I correct in understanding you on that point?

Senator BAYH. Yes, there are some rather tender negotiations going on right now, I understand.

Senator HANSEN. What do you mean by tender?

Senator BAYH. They are between the Alcan people, the State of Alaska and the producers and are in the earliest stages. I don't know all of the details but I would hope they can iron them out in an amicable manner and not be forced to do something by the Congress.

Senator HANSEN. If the State of Alaska were to provide some additional financing, how would it be repaid?

Senator BAYH. I would assume that since the State of Alaska is going to benefit from some $7½ billion of revenues plus annual property taxes, this would mean they would make a little less money.

I think that when we determine how we will deliver that gas, we must look at it as a natural resource.

The Government could get into a public works project and make this a public utility and move that gas out of there. Frankly, I prefer to let the free enterprise system, based on a profit motive, which has done pretty well in this country, build the project. But the free enterprise system has done well because he who makes a profit, takes a chance. Although we are talking about an insurance policy, an auxiliary system that we hope is not necessary, I see nothing wrong with first seeing that the producers who have by far the most to gain from the building of this pipeline take the first risk and then, the State of Alaska, which stands to gain next, take the second risk.

I prefer not to ask the Federal Government to get involved although I guess I would be prepared, if necessary, to do this, as long as the producers' returns are modified accordingly. I don't think those who are going to make the profit should be absolved of any responsibility for bearing the burdens that go along with their gains.

Senator HANSEN. I am not familiar with the State government of Alaska but as a former Governor of the State of Wyoming, I can say that it would seem to me to be a rather unusual circumstance for a State to give an open ended blank check guarantee that it would provide the financing for a venture of this kind.

I am certain, although I could not cite you chapter and verse, that there are some specific laws in Wyoming that would probably prohibit that. Is there adequate legal provision in the constitution of the State of Alaska to do what you propose that State does?

Senator BAYH. I must say I am not sure of the State of Alaska, I am sure that the State of Indiana would not permit any open ended guarantee. We're not talking about an open ended guarantee.

As best I recall the details, the State of Alaska offered to guarantee up to $900 million of the El Paso project debt with the hope that it would never have to ante up on that.

Senator HANSEN. You do have a specific amount in mind or you do not have a specific amount in mind?

Senator BAYH. There is a specific amount cited in the President's report for the State of Alaska—$900 million—and I believe Alcan has suggested $2 billion for the producers.

Senator HANSEN. That's a rather trivial difference. I would not think it would be of any concern except to the people in the State of Alaska.

Senator BAYH. I don't think $2 billion is trivial even in the frames of reference that we are used to discussing, Mr. Chairman.

Senator HANSEN. Thank you, I have no further questions at this time.

Senator BAYH. Mr. Chairman, I just have problems with the other alternative—an all events tariff—which is the one that was proposed by the companies, and, I assume, is favored by Alaska and the producers. This type of guarantee would have the consumers, or the would-be consumers, paying for the cost of something before they get any benefit from it.

Maybe you can explain that to the people in Wyoming but I imagine it would be very difficult, and understandably so, to explain to people in Indiana why they ought to pay for something from which they may never benefit, especially when there are companies prepared to make a profit from the pipeline if everything goes well but not to take a loss if things do not go well.

Senator HANSEN. I sure don't disagree with you on that, despite the fact that this project will involve the State of Alaska and indirectly, I guess, it certainly can be fairly stated that the typical Alaskan, the average Alaskan would benefit directly or indirectly from its construction.

I think to ask the State as a political entity to undertake this sort of obligation that I understand you to spell out seems to me to be one that would be clearly prohibited by law, by Constitution. That may not be the case at all, but I would think it would be.

Senator BAYH. I understand the State of Alaska offered backing like this to the El Paso project.

Senator HANSEN. It could be.

Senator BAYH. Obviously, I think if I were a Senator from Alaska——

Senator HANSEN. Who made the offer, do you know?

Senator BAYH. I do not know.

Senator HANSEN. Would it have been the Governor?

Senator BAYH. I imagine it would have been the Governor. I could argue, if I were a Senator from Alaska, how the El Paso project would benefit my State more than the Alcan route, and I can understand that.

And if I were in Alaska, a citizen, or if I were a producer with all that gas sitting up there, I would like nothing better than not to have to bear any of the risk associated with financial guarantees.

I think the important question to ask is: What is equitable? First of all, the producers will make somewhere between $20 and $25 billion profit.

Senator HANSEN. You mean that's what they expect to make.

Senator BAYH. That's what they expect to make, that's right, and I hope they do because I want to develop not only the gas reserves that we know are there now, but additional gas that we have reason to believe may be there.

Senator HANSEN. On that point, speaking of revenues, I expect it would be fair to assume that any investor in the pipeline would look to revenues in order to recover the investment he had made plus a reasonable amount of interest.

Let me ask you this. If the cost of the pipeline were to increase rather sharply—as indeed was the case with the Alyeska pipeline—and if the attitude of the President continues as it is—I notice over the weekend he said he would veto any bill which would de-regulate the price of natural gas—would it be fair to assume that, when you look at the burner tip costs, if the cost of transportation were to be sharply escalated, would that not mean that, in order to keep rates uniform or on an even keel, you would have to drop the value that would be paid the producers of the natural gas?

Is this a fair conclusion to reach?

Senator BAYH. No, Mr. Chairman, I don't look at it that way.

Senator HANSEN. How would it be different?

Senator BAYH. I would assume that as the price of transporting gas goes up, that the price of gas at the end of the pipeline would also go up. No regulation scheme that I have seen is based on any other provision than reasonable fair cost which would have to include the cost of transportation.

We might disagree about what reasonable fair cost is, but I have not seen anyone who suggested that transportation is not a reasonable cost to be added to the price of gas, once the gas is paid for from those who produce it.

Senator HANSEN. I have interrupted you a great many times and I appreciate your clarification.

Senator BAYH. No; that's all right. I understand your concern and I share it. As I have said, I am hopeful that this very controversial issue is one we will never have to deal with, but I think it is only wise to anticipate the possibility and try to resolve it in advance.

I note that the Alcan cost estimate is $7.6 billion. The administration upped that to $8.9 billion in its study and the financing plan presently being proposed is $10.3, taking inflation into account. So there is pretty good cost escalation in there, plus the fact that they have the Alyeska experience which I am sure was considered in the original Alcan cost.

One of the things that I like about the President's plan is the resolution of the Dawson Spur matter. I know there has been some controversy about why the United States should pick up a small portion of that.

But I think one of the most important features of that agreement is that in exchange for assuming some of those costs, there is a real incentive for the Canadian companies involved in the project to keep the cost overruns down, because as those cost overruns increase, then the amount that the U.S. companies have to pay for that small section of the spur goes down. So that's a real incentive for them to keep the costs down there.

Mr. Chairman, I think that I have pretty well covered most of what I wanted to say. I should point out that one of the things that appeals to me about this route is that it offers the possibility of continued imports of Canadian gas.

In its latest analysis of Canada's gas demand/supply projections, the Canadian National Energy Board has indicated that access to Canadian frontier reserves will be necessary to avoid curtailment and eventual cutoffs of present Canadian gas exports to the United States.

Construction of the Alcan system will give the Canadians access to their northern frontiers economically at the time they decide it is in the best interest of both our countries. Thus, selection of Alcan offers the most certain way to avoid reduction or cessation of present imports—a cessation of up to 2.7 billion cubic feet of gas per day—which, should it occur, would not even be entirely offset by new Alaskan gas flows through the pipeline.

Put another way, within a decade or so, gas supplies totaling 5.1 billion cubic feet may be available daily as a result of an Alcan selection. In other words, we will not be in the situation of bringing in Alaskan gas in the one hand and turning off Canadian gas with another.

Finally, Mr. Chairman, in conclusion, I would like to emphasize the importance of prompt congressional action so that the Alcan project can be started. Any delay will increase the cost of building the pipeline because of inflation, and postpone the availability of Alaskan gas, and the additional volumes of Canadian gas to U.S. markets.

If we act quickly, by the winter of 1979–80, Alcan can be delivering up to 800 million cubic feet of Canadian gas per day to the United States. When the pipeline begins full operation in 1983, it will carry 2.4 billion cubic feet of Alaskan gas per day. This represents a new supply of domestic gas of 876 billion cubic feet per year.

I must note, Mr. Chairman, the prompt congressional action required includes not only approval of the President's decision but also the passage of legislation regarding the pricing of natural gas. An essential step that must be taken before financing can be committed, and construction started, is the negotiation and approval of contracts for the sale of Alaskan gas. It is highly unlikely that such contract agreements will be reached until there is some certainty as to Federal pricing policy.

In this regard, Mr. Chairman, I would like to express my own view that deregulation of Alaskan gas would be very unfortunate for the American consumer. Alaskan gas was discovered 9 years ago. It is there with the Alaskan oil and is readily accessible. Indeed, it must eventually be disposed of if the producers are to efficiently use their oil reserves. To provide them windfall profits through deregulation would be a clearly unnecessary incentive, be most unfair to American consumers, and probably add only more uncertainty to the ultimate cost of Alaskan gas.

With this said, Mr. Chairman, let me thank you for permitting me to testify today. I hope that the Congress, led by the committee, will oversee the construction of the Alcan system so that we can be sure that both Alcan and the executive branch are doing their jobs.

It has been a pleasure to be with you today and I appreciate very much the opportunity to share these thoughts with you.

Thank you.

[The prepared statement of Senator Bayh follows:]

STATEMENT OF HON. BIRCH BAYH, A U.S. SENATOR FROM THE STATE OF INDIANA

Mr. Chairman, I am happy to be here today to testify in support of the President's decision selecting the Alcan project to bring natural gas to the lower 48 states from Alaska.

These hearings could not be more timely. As we are all aware, the Senate has spent much of its time during the last week debating the crucial issue of how to assure that American towns and cities, and farms and factories will not again suffer the hardships and dislocations experienced last winter as a result of natural gas shortages.

Natural gas is a critical component of the Nation's total energy supply, making up about one-third of all energy used in this country. Although many of us have differed about the best way to provide ourselves an adequate supply of natural gas as we gradually move toward use of alternative and more plentiful fuels, all of us agree that we must do every thing possible to reduce the probability of continued gas curtailments in the winters ahead. One critical factor in giving us this assurance will be prompt access to our Alaskan gas and continued exports of Canadian gas until we can manage comfortably without it.

Recognizing the need to act quickly to build a transportation system to bring our Alaskan gas south, last year the Congress passed the Alaska Natural Gas Transportation Act which established special procedures for selecting an Alaskan gas transportation system. At the time we passed the Act, there were three competing system proposals. The exhaustive selection procedures prescribed by the Act, as well as those undertaken by the Canadian government, have clearly indicated the superiority of the Alcan project over the others. In fact, Alcan's two competitors—Arctic Gas and El Paso—have voluntarily withdrawn as a result of this extensive scrutiny and the strong support for Alcan evident within the executive and legislative branches of our government.

Earlier this month, the President formally recommended the Alcan route to the Congress. Responsibility for prompt action, which will permit a quick start on construction, now rests with those of us who sit in the Congress, for we must confirm the President's decision before it can be implemented. I urge this Committee and the Senate to move rapidly to approve the President's decision.

Mr. Chairman, President Carter's choice of Alcan reflects its superiority in almost every respect. Its advantages include:

Lower cost of service;

Early delivery of Alaskan gas;

Even earlier delivery of new volumes of Canadian gas;

The possibility of continued Canadian gas exports to this country;

Clearcut environmental superiority;

Private financing of the system;

Direct pipeline delivery of Alaskan gas to regions both east and west of the Rocky Mountains;

A high degree of safety and reliability; and

Significant savings in the amount of gas required as fuel for the transportation system.

I will not go into these advantages in depth. Other witnesses will describe them fully. In addition, I have circulated a fact sheet to every Senator which I would like to submit for the hearing record which describes Alcan's advantages in some detail. Instead, I would like to take this opportunity to comment on two particular points—the project's financing and the possibility of continuing Canadian exports of gas to the United States—and make clear the importance of quick congressional action.

The President's decision specifies that the Alcan project will be financed without any federal government or consumer guarantees. The Administration envisions that the equity funds for the project will be provided by gas transmission and distribution companies. Both Alcan and the administration anticipate that the necessary equity and debt can be raised because of the economic desirability of Alaska gas and the viability of the Alcan transportation system. Nonetheless, the President's report does indicate that because of the possible cost overruns associated with a project of this magnitude and character, it may be necessary for some sort of cost overrun guarantees to be extended to creditors to assure them that overruns will not lead to abandonment of the project.

Mr. Chairman, there are, in my opinion, two appropriate sources of such debt guarantees—the producers of Alaskan gas and the state of Alaska, both of whom will benefit enormously from this project. The only alternatives to these two parties guaranteeing against these risks is for the federal government or gas consumers to take up the financial burden. The state of Alaska and the major producers have previously indicated that they are not inclined to guarantee the Alcan project, and I think it is extremely important to take a few moments to indicate why it is more appropriate for these two parties to provide financing assistance than for either the federal government or American consumers to do so.

Alaskan gas producers stand to profit handsomely from their large gas reserves in Alaska once a transportation system is in place. In his testimony yesterday, Secretary Schlesinger indicated that the major Alaskan producers except approximately $20 to $25 billion in profit from the gas sales the Alcan project will make possible. It seems to me that asking them to assist in financing the project is reasonable and equitable in light of their vast financial resources and the profits they will realize as a result of the project.

Although I would prefer that the producers bear this primary responsibility, the same logic applies to the state of Alaska, which could receive up to $7.5 billion in revenues from royalties and severance taxes. In addition, if this pipeline is built, the state will receive other substantial benefits, including $50 million per year in property taxes. Given these benefits, it seems to me that asking the state to assist financially is not unreasonable.

Contrast these two options, Mr. Chairman, with the other two possible risk guarantors—the federal government and American consumers. The President's report has clearly pointed out that federal guarantees would be inappropriate: it would set an unnecessary precedent for large energy projects; cause all taxpayers to subsidize the project when all will not receive benefits from it; yield artificially low gas prices through low interest rates; reduce incentives for sound management practices; and place the government in the conflicting roles of guarantor and regulator.

As the President's report also points out, the risks of noncompletion should not be borne by consumers. To ask consumers to assume this risk does not seem warranted, especially when other parties with a strong business interest and the opportunity to profit from the project, stand by and refuse to assume any of the burden at all. Simple justice seems to me to suggest that major beneficiaries of the project should be willing to help get it off the ground before we reach further into the pockets of American consumers.

Mr. Chairman, I would also like to comment on two attractive and unique assets associated with the Alcan proposal: the ability to deliver significant amounts of additional gas to the United States by the winter of 1979–80 and the hope of continued Canadian exports to the United States in the coming decades.

Alcan has already contracted for up to 800 million cubic feet of additional Canadian gas daily from Alberta for delivery to the Lower 48 starting in the winter of 1979–80. By planning to start construction of the southern end of the pipeline first, Alcan can distribute this desperately needed Canadian gas to the Lower 48 by the winter of 1979–80 and continue these deliveries until the northern segments of the pipeline are built to bring our own Alaskan gas south in the winter of 1982–83.

In addition, Alcan offers the possibility of continued imports of Canadian gas. In its latest analysis of Canada's gas demand/supply projection, the Canadian National Energy Board has indicated that access to Canadian frontier reserves will be necessary to avoid curtailment and eventual cutoffs of present Canadian gas exports to the United States. Construction of the Alcan system will give the Canadians access to their northern frontiers economically at the time they decide it is in the best interest of both our countries. Thus, selection of Alcan offers the most certain way to avoid reduction or cessation of present imports—a cessation of up to 2.7 billion cubic feet of gas per day—which, should it occur, would not even be entirely offset by new Alaskan gas flows by pipeline flows. Put another way, within a decade or so, gas supplies totaling 5.1 billion cubic feet may be available daily as a result of an Alcan selection.

Finally, Mr. Chairman, I would like to emphasize the importance of prompt Congressional action so that the Alcan project can be started. Any delay will increase the cost of building the pipeline because of inflation, and postpone the availability of Alaskan and the additional volumes of Canadian gas to U.S. markets. If we act quickly, by the winter of 1979–80 Alcan can be delivering up to 800 million cubic feet of Canadian gas per day to the United States. When the pipeline begins full operation in 1983, it will carry 2.4 billion cubic feet of Alaskan gas per day. This represents a new supply of domestic gas of 876 billion cubic feet per year.

I must note, Mr. Chairman, the prompt Congressional action required includes not only approval of the President's decision, but also the passage of legislation regarding the pricing of natural gas. An essential step which must be taken before financing can be committed and construction started is the negotiation and approval of contracts for the sale of Alaskan gas. It is highly unlikely that such contract agreements will be reached until there is some certainty as to the federal pricing policy.

In this regard, Mr. Chairman, I would like to express my own view that deregulation of Alaskan gas would be very unfortunate for the American consumer. Alaskan gas was discovered nine years ago. It is there with the Alaskan oil and is readily accessible. Indeed, it must eventually be disposed of if the producers are to efficiently use their oil reserves. To provide them windfall profits through deregulation would be a clearly unnecessary incentive, be most unfair to American consumers, and probably add only more uncertainty to the ultimate cost of Alaskan gas.

With this said, Mr. Chairman, let me thank you for permitting me to testify today. I hope that the Congress, led by the Committee, will oversee the construction of the Alcan system so that we can be sure that both Alcan and the executive branch are doing their jobs.

It has been a pleasure to be with you today and I appreciate very much the opportunity to share these thoughts with you.

Thank you.

Senator HANSEN. Mr. Bayh, I have one final question or at least it's final for the moment. Do you know if the State of Alaska favors deregulation of the price of natural gas or does it favor continued regulation?

Senator BAYH. I would assume they would favor deregulation, Mr. Chairman.

Senator FORD. I have no questions, Senator.

Senator BAYH. Mr. Chairman, both of you gentlemen, I want to say how much I appreciate—I am very grateful, gentlemen, for the possibility of being heard, particularly at this very unsenatorial hour.

Senator FORD. We are trying to change that image of coming in late and leaving early, we are coming in early and leaving late. Thank you.

Senator BAYH. Thank you.

Senator FORD [presiding]. The next witness this morning is the Honorable Ted Stevens, U.S. Senator from Alaska. Senator Stevens.

STATEMENT OF HON. TED STEVENS, A U.S. SENATOR FROM THE STATE OF ALASKA; ACCOMPANIED BY JOHN BURNETT AND JACK FERGUSON

Senator STEVENS. Good morning, Mr. Chairman. I find it is very nice to have a seat warmed up by a Hoosier. Being a former Hoosier, I understand what the gentleman who preceded me said, notwithstanding the fact that I don't quite agree with it as he indicated.

Mr. Chairman, I would like to have here at the table with me John Burnett and Jack Ferguson who have worked with me on this pipeline issue in case there are any questions that come up that they might assist in discussing.

As my colleague did, I think perhaps the best thing to do would be to try and present this statement and answer any questions that you might have.

Mr. Chairman, let me thank you again for permitting me to sit with the members of the committee during these hearings and for the opportunity to appear before you.

The selection of a route to ship Alaska's natural gas to the South 48 has been an issue of vital concern to me and to the residents of my State for some time. We are here to look into the President's decision on selection of the Alcan proposal.

I am sorry that the one alternative, the one option left to the United States in case of default by Alcan, has withdrawn its application. If for any reason the Alcan pipeline is not built or completed, I hope that we can reconsider an LNG route from Tidewater, Alaska to the west coast.

In any event, I am not here to discuss the all-American concept of transporting natural gas. We in Alaska take some comfort in the fact that the most favorable of the two Canadian routes was selected.

The effort of Arctic Gas to ship Alaska's natural resources out of our State without benefit to the people of Alaska was defeated, primarily by Canadians and this is a fact we shall not forget.

We are, in fact, indebted to our neighbors for blocking the Arctic proposal. We won, but only if the Congress can be assured that in fact the Alcan pipeline will be built and built without delay. There is a very real possibility that the Alcan pipeline may not be built under the circumstances foreseen by the administration and as expressed by Dr. Schlesinger to this committee yesterday.

In the brief time I have today, let me outline some of my concerns which have led me to question the optimistic timetable for the Alcan pipeline expressed by Secretary Schlesinger.

First with regard to financing. There is serious question that this project can be built with the financing scheme presented in the Presidential report. The President has predicated his assessment for Alcan's financeability on the assumption that the State of Alaska and the producer companies of the North Slope will participate in equity ownership and debt guarantee of the pipeline.

I told Dr. Schlesinger this yesterday and I think it bears repeating today—to my knowledge, the State of Alaska has no intention at this point to participate in any financing of the Alcan line nor have the producers indicated their willingness to participate.

In fact a week prior to the President's decision, the Governor of the State of Alaska wrote the President stating the State had no intention of financially involving itself in the Alcan project. The Governor also said that even if he were to change his mind, it was unlikely the legislature would approve such a plan.

Similarly, none of the major producers of the North Slope natural gas have stepped forward and indicated a willingness to participate in either the equity ownership or a debt guarantee of Alcan as is indicated in the Presidential report.

I personally asked all of the producers of North Slope gas if they were willing to participate in financing the all-American project and in no instance did I receive any indication that they were willing to do so.

The report's financial analysis concludes that the project can be privately financed. However, when asked, Dr. Schlesinger testified that their conclusion was based on eight-eighths of the gas.

He conceded the administration had not seriously considered the State's options of keeping their one-eighth of the royalty gas within the State. The report may have erroneously concluded that there were sufficient incentives for the State to commit its one-eighth of the gas to the Alcan line.

I am told that the State's commissioner of revenues, who will testify before the committee later this week, believes that the inherent risks in the Alcan line, put with the opportunity for gas-based industries within the State, may result in the State's selling only a portion of its gas or none at all.

The residents of my State pay the highest price for the use of natural gas in the United States. I am sure that they cannot be faulted for demanding that the State exercise its options to use one-eighth of the gas for their own use rather than take payment for the royalty gas.

So, Mr. Chairman, in view of that possibility, I urge the committee to take exception to the President's report with respect to the finance-ability of the Alcan line under a seven-eighths transmission mode.

Mr. Chairman, we all understand that delay will increase the costs of service to the consumer. Financing aside, there are other reasons to believe that there will be substantial delay in the construction of the Alcan pipeline.

We cannot permit history to repeat itself. As everyone knows, we suffered from a 4-year delay because of court action and congressional approval with the trans-Alaska pipeline and it is my hope that this will not happen.

But, there are problems with regard to Canadian approval, native claims, and provincial conditions that may well result in untimely delay. Therefore, it is reasonable to assume that there will be cost overruns resulting from actions that the builders of this pipeline will have no control over.

Understandably then, the variable rate of return which this report states is the incentive to the builders to keep costs down are only one part of a very complicated problem. Without even questioning the adequacy of the variable rate of return concept, it is questionable whether the incentive to prevent delay will in fact have any impact on those who may cause the delay.

In fact, it might be said that the provinces themselves might profit from delay.

Let me amplify that a little bit. They have a tax base. As the tax base increases, the return to the province increases. There is nothing in this agreement at all to encourage the Provinces of Canda to keep the taxes down except the antidiscrimination provision.

If this is the largest project in those Provinces, the smaller Provinces could well add to their taxes, as long as the taxes were not discriminatory, the bulk of the taxes will be coming from a non-Canadian project and the Provincial income will increase with a rate of valuation of this project which is an incentive to cost overrun and not a disincentive.

At this point, it is of little benefit to question the filings of each of the applicants and the interpretation of the departments which concluded that there would be a 17 cents cost of service benefit should the Alcan be built.

But, the President has overlooked the inevitability of LNG facilities being built in Alaska. As you know, we have 15 highly potential oil and gas basins in Alaska on and off shore. Only two of them are producing now, and I would remind you that 70 percent of the outer Continental Shelf is off Alaska. The estimated potential recoverable gas offshore Alaska alone totals more than 188 trillion cubic feet.

These reserves will have to be transported by LNG. This is a subject that I personally pointed out to the President. It is reasonable to assume that the American consumer will bear the cost of the LNG facilities which have to be built to transport tidewater offshore gas from Alaska.

Gentlemen, if you examine this map, you will see one of the reasons why we were not over-enthusiastic about the Alcan line. The Gulf of Alaska Province, Cook Inlet, Kodiac Island Province, Bering Sea, all the way up to the Chukchi, all of those Provinces that have great potential for gas production are offshore or near shore.

We wanted to have the LNG tankers and LNG major plant built now associated with Prudhoe Bay gas which is a known reserve and have those tankers available to serve smaller LNG plants around the coastline of Alaska for export to the South 48 as the other reserves become producible.

That is not possible now. That is behind us as far as Prudhoe Bay is concerned. But I think it bears well to remind the American public that ultimately the consumers of the United States will pay for that LNG mode of transportation and ultimately they will pay for the LNG plants and it will result in a duplicate charge.

They will pay twice because once this pipeline is through it will not serve those offshore potential areas. As a matter of fact, once we have completed use of this pipeline, it will be owned by Canadians. The equity will not be owned by the United States and it will not be available for U.S. service, it will be available for transporting Canadian gas to Canadian customers.

The Alaska Natural Gas Transportation Act of 1976 provided for a limitation of judicial review. The President was authorized to submit a waiver of all laws which he felt need to be waived to expedite issuance of permits for a pipeline.

The President's decision requested waiver of only two provisions of Federal law. I suggest this committee and its competent staff will want to review all other applicable laws to determine if the President's request is all-inclusive if we are to avoid delay.

Canadian Federal/Provincial approval. I am surprised, Mr. Chairman, that according to Dr. Schlesinger and the President's report, the only commitment that the United States has from the Provinces is a "statement of agreement in principal" and an offer to "cooperate" under the terms of the Hydrocarbon Treaty ratified last month by the Senate.

I direct your attention to page 81 of the President's report in which the Province of British Columbia says that the extent of cooperation with any agreement must still be worked out. Dr. Schlesinger said yesterday that the letters of exchange have yet to be completed.

Because of strong Provincial autonomy in Canada, this executive agreement is founded on a very thin thread, far too thin and far too weak to assure compliance by the Provinces. One need only to look into history.

One such example is the Columbia River Treaty. Following signing of the treaty, British Columbia held up the project until it received nearly a quarter of a billion dollars for a nonrelated project—the Peace River Dam. It was a classic Provincial finesse and a valuable lesson to be learned by the Americans.

The concern we in the Congress should have is that the Provinces have a far greater degree of leverage in extracting concessions from Ottawa than any State has on the administration in Washington.

Regardless of the agreement between the United States and Canadian Governments, we must realize that it is not binding on the

Provinces. Ottawa cannot unilaterally preclude the Provincial legislatures from exercising their lawful rights to impose direct taxes on this pipeline. And the United States would have difficulty holding the Canadian Government liable for the Provincial right of the Provinces to levy whatever lawful direct taxes they wanted on portions of the line that cross their land.

Although I would be glad to discuss this at some length under questioning, there are statements by British Columbia to extract every penny possible from the pipeline. We in Alaska who go through Canada on our way home and spend a great deal of our personal time with our neighbors know some of these comments better than anyone else.

For example, former Premier and candidate David Barrett told an emergency debate in the British Columbia Legislature that it should impose a right-of-way charge of $842 million for crossing British Columbia territory and for the resulting "social upheaval" in the northern regions of the Province—an area of unsettled Native claims. None of those costs are included in the financial analysis of this pipeline.

Although the payment of Native claims is prohibited, according to Dr. Schlesinger, under the terms of the agreement the Province might levy such a charge as a right-of-way fee or a direct tax, such as a property tax—to pay for the settlement and implementation of Canadian Native claims, as it did to pay for another nonrelated project such as the Peace River Dam in the Columbia River Treaty.

Mr. Chairman, the possibility that another Columbia River Treaty snafu may develop is all too real. The only assurance the administration has from Canada and the Province is that they intend to "cooperate."

Perhaps, this committee should ask the provincial leaders themselves if the Provinces will submit to Congress statements concerning what they intend to extract from the pipeline consortium, and ultimately the American people.

Perhaps we should ask them what added charges are they going to put on the line and ask British Columbia whether it will pay the settlement and implementation of the Nishga Indians' claims from funds derived from the pipeline.

The sorry thing about this arrangement with our neighbors to the north is that it is in the form of an executive agreement. The largest project ever undertaken by private financing in the history of mankind is submitted not as a formal treaty or protocol for the advice and consent of the Senate as such international agreements are usually handled, but by an agreement between two chiefs of state.

Labor and Canadian content. Mr. Chairman, I want to briefly touch on another nettlesome problem that has not been solved but one which may cause a great deal of concern to the American people.

Noticeably absent from the agreement is any mention of "content"—that is the nationality of labor and material used in the construction of the line. Can we assume by omission that the Canadians intend to build their portion of the line lock, stock, and barrel?

Mr. Chairman, according to the NEB, they are indeed planning just that. According to the Canadian Government, the pipeline through

Canada will mean an expenditure of more than $7 billion in the Yukon and Alberta alone. Two Canadian steel corporations, Stelco and Interprovincial Steel have both been earmarked to produce the pipe for the 2,000 miles through Canada.

Yet, Mr. Chairman, the agreement barely addresses the question of Canadian content, other than on page 60 where it states simply that "each Government will endeavor to ensure that the supply of goods and services to the pipeline project will be on generally competitive basis." The question here is whether or not the competition ranges across the border opening the contracts to bidding in both nations.

Considering that the Alcan route means an additional deficit in the balance of payments of about $10 to $12 billion, American labor at least should have a fair share of those contracts awarded inside Canada.

For example, U.S. Steel is building a plant in Bay Town, Tex., with the capability of producing 48-inch pipe. Will this plant have an opportunity to bid on the contracts for the pipe? That is a question that is as yet unanswered, in my opinion, Mr. Chairman, and one that this committee ought to look into.

I am also concerned that contractors with extensive experience in building the trans-Alaska pipeline be allowed to participate in the construction of the pipeline that is to be paid for by American consumers ultimately.

I have attempted here to delineate some of the concerns I have and those which are problems to the completion of this line. That there are benefits to both nations from the Alaska line is unquestioned.

But I want to caution this committee and the Congress that although this agreement has been touted as an example of international goodwill and cooperation between the United States and Canada, it may very well have the opposite effect.

Indeed, unless we are absolutely certain that all the questions have been answered and all the problems solved prior to our approval of the President's decision, then, Mr. Chairman, I fear that we are faced with the prospect of having no pipeline at all.

I want to stress that we in Alaska want to work with Alcan to make certain that there is actually a pipeline from the North Slope to the South 48. We will do everything we can to make sure that Alcan is welcomed in our State. But, Mr. Chairman, I also hope that we are assured here in Washington that the line will be built.

As I state, I am very concerned about the possibility of delay—delay which the President himself in his letter of transmittal to the Congress said would "greatly increase the total cost of the pipeline".

I ask that, as I did yesterday, that the record remain open that we might submit detailed questions to the administration. But, gentlemen, let me again reiterate, we do not oppose the construction of the Alcan pipeline, there is no other alternative now.

On the other hand, if this Congress creates a record which is merely a rubber-stamp of the President's report without inquiring, as the act we passed last year contemplated that we would, into the basis of that recommendation and satisfying ourselves that the project will in fact be built, that it is in fact financeable and that the governments of our neighbor to the north have committed themselves to our time frame for construction, then we will have brought on the American public a delay which will make the 4-year delay of Alyeska pipeline seem very insignificant.

The delay in the St. Lawrence Seaway, gentlemen, from the date of the signing of the treaty to the initiation of construction was 22 years. The delay in terms of the Columbia River Treaty alone, a very small project compared to this, was well over 4 years.

I submit to you that in both instances, both the St. Lawrence Seaway and the Columbia River Treaty, the agreements between our two governments were more precise, more exact, and more designed to prevent delay in the original instance. This one is not and I think that the Congress itself must take upon itself the task of assuring that this pipeline will be built.

Again, I hope the record is clear that as far as Alaska is concerned, we are not taking the position that the Federal Government should not be involved in financing this pipeline, either through guarantees or direct participation.

I for one believe that without a Federal guarantee, it may never be built. Thank you very much.

I think I could answer the Senator from Wyoming that the Alaskan position is almost unanimous on natural gas for the reason that we desire certainty in the industry and we think that certainty will come when market factors are involved in supply and demand and it can be projected that Alaska's gas will in fact be in demand and the market will pay for it.

The uncertainty involved in the picture today is going to lead to the questions of financeability that the Senator from Indiana and Dr. Schlesinger and the President's decision and report have mentioned.

The unfortunate part of it is that the conclusion is that Alaska and the producers who stand to profit from development of the resource which is true, we are one-eighth owner and we will obtain the rights to use the gas or take the value of one-eighth of the gas, are looked to as a prospect for guaranteeing cost overruns.

It is a very interesting thing because the profit of the State and of the producers will decrease as the cost of transportation increases, assuming a controlled market or a free market.

But they want the State of Alaska producers to guarantee against cost overruns. We are the very people who stand to lose the most if in fact there are cost overruns and the idea is that we should guarantee against those cost overruns which in fact would bring about an incentive to make them occur.

There is no mechanism involved in the cost overrun to prevent them from occurring and that is one of the great problems about this State entering into this. The State of Alaska did offer $900 million if the other route was selected in the form of guaranteeing of the lowest form of the bonded indebtedness entered into by that pipeline company.

I will get into this map behind me in a moment to show you why we did that. It had nothing to do with either of these proposals but it had to do with the future potential of Alaska gas and what we view to be our interest in the full development of that gas potential and the cost of developing that full potential and why we think the other route would have been more suited to the full development of Alaska's potential.

Let me state with regard to these overruns, we don't believe that companies cause overruns. We think cost overruns are caused by governments, by inflation, by excessive regulation, by taxes, by discriminatory charges.

We don't feel that the mechanisms in the President's report to control cost overruns would be affected because they will be applied against the pipeline company. The company itself will do everything it can to keep the cost down because it will increase its profit margin if it does.

It is the Government of Canada that we fear in terms of cost overruns and I am certain that, as I mentioned yesterday, the United States stands to gain a great deal more as a government than the State of Alaska does in terms of taxes upon the pipeline company, income from the pipeline, income from the producers, the total income generated from the use of the resource that we are prepared to export and I hear nothing that talks about putting the credit of the United States at risk as far as cost overruns are concerned because the Government has refused to recognize that requirement.

I think, as I will go into later here in my statement, that we ought to keep the door open for Federal guarantees of the cost of this project in order to assure financeability. This is a government-to-government proposition we have entered into for the first time and, as I said, we feel that the cost overruns will come from the actions of Canadian Governments, either Federal or Provincial and not from Canadian private enterprise.

If there is any entity in a position to keep down the costs on this project, it is the Federal Government and it is the actions of the Federal Government vis-a-vis the governments of Canada that will in the final analysis protect the American consumer against excessive costs in Canada.

Senator FORD. I thank the Senator. I have a question or two and I think you have raised some serious concerns that this committee should face.

On page 5, Senator, you refer to a waiver of all laws to expedite issuance of permits. You say, "I suggest this committee and its competent staff will want to review all other applicable law to determine that the President's request is all-inclusive if we are to avoid delays."

Of course, you have experienced—if the stove is hot, you don't touch it again. Do you have any recommendations to the committee of the various areas that should be reviewed in order to avoid the delay you are so concerned about in your statement?

Senator STEVENS. We will be glad to submit to the committee a list of laws that other applicants suggested should be reviewed in connection with the project if they were to receive the approval.

Our experience indicated, with regard to the right-of-way law that a very technical deficiency in the right-of-way law led to a 4-year delay. We also know that under the National Environmental Protection Act, dissidents can raise objections and we have no way of controlling those who oppose ultimately the construction of any pipeline in our State.

They have the right also to go to court to challenge the construction of this line through the United States, either through Alaska or through the south 48 in our courts under our laws to challenge this line.

I submit that we have not included in this legislation that authorize the President to take this action, the type of judicial review limitation which was contained in the Alaska Oil Pipeline Act.

As a consequence, we can, I think, anticipate the probability that court action may be involved as far as this line is concerned. For political reasons, perhaps, the President might not have desired to request such waivers, but nothing prevents the Congress from insisting upon such waivers if it is, in fact, to accelerate the construction of this line.

I think that the proponents of Alcan ought to be the first to welcome a complete review and a precise statement as to the waivers of Federal law that will prevent unnecessary delay through vexations litigation that might be brought.

[Subsequent to the hearings, Senator Stevens submitted the following:]

UNITED STATES SENATE,
COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION,
Washington, D.C., October 11, 1977.

Hon. HENRY M. JACKSON,
Chairman, Committee on Energy and Natural Resources,
U.S. Senate, Washington, D.C.

DEAR SCOOP: Enclosed is a list of permits and legal requirements that would be applicable to the Trans-Alaska LNG proposal for the transportation of North Slope natural gas.

This is the list which I mentioned in my testimony to the committee on September 27 and which the committee asked me to provide for the record. As the El Paso project would involve both land and water links, not all of the permits listed here would be applicable to an all-land route. But, those requirements on this list which are applicable to the overland portions of the project are so numerous and so diverse that waiver of only two provisions of Federal law may not be adequate to insure timely completion of the Alcan project.

Thank you for this opportunity to provide this material to the committee.

With best wishes,

Cordially,

TED STEVENS,
U.S. Senator.

Enclosure.

Section 9—Permits and compliance with other regulations and codes

Table of Contents

Section	*Title*	*Page*
9.1	PERMITS	9.1–1
9.1.1	Authorities consulted	9.1–5
9.1.2	Permits and authorizations obtained to date	9.1–5
9.2	COMPLIANCE WITH HEALTH AND SAFETY REGULATIONS AND CODES	9.2–1
9.2.1	Authorities consulted	9.2–5
9.2.2	Procedures to be followed	9.2–5
9.3	COMPLIANCE WITH OTHER REGULATIONS AND CODES	9.3–1
9.3.1	Authorities consulted	9.3–2
9.3.2	Procedures to be followed	9.3–2
9.4	SPECIAL CASES	9.4–1
9.4.1	Liquefied natural gas facilities	9.4–1

9 PERMITS AND COMPLIANCE WITH OTHER REGULATIONS AND CODES

9.1 PERMITS

This section identifies those permits, licenses, certificates and approvals which may be required for implementation of the proposed Alaskan Project. If requirements additional to those presented herein are determined subsequent to the filing of this Report, Applicant will, of course, take whatever action is necessary to secure such requisite authorizations.

In itemizing these permits, licenses, certificates and approvals, Applicant does not necessarily concede the jurisdiction of any agency or governmental unit, or the validity or applicability of any of the statutes, codes or regulations here enumerated.

Federal permits

The Mineral Lands Leasing Act, 30 U.S.C. § 181, *et seq.*, requires approval of the Department of the Interior for temporary use of and the grant of rights-of-way across most federal lands.

The Mineral Lands Leasing Act was amended in 1976 and regulations pursuant to these amendments have not been promulgated. Regulations under the prior act are found at 43 C.F.R. Part 2800.

The Rivers and Harbors Act of 1899 authorizes the Corps of Engineers to approve and issue permits for the construction of any improvement to a harbor or navigable river. 33 U.S.C. § 417, § 472. Regulations are found generally at 33 C.F.R. § 209.120, *et seq.*

On December 23, 1970, the Chief Counsel, U.S. Coast Guard, concluded that a sufficient factual basis existed to require permits for bridges and pipeline crossings to be constructed over the following named waters of Alaska:

Lowe River
Tonsina River
Klutina River
Copper River
Tazlina River
Gulkana River
Tanana River
Salcha River
Piledriver Slough
Chena River and Tributaries
Chatanika River
Tolovana River
Hess Creek
Fish Creek
Bonanza Creek (North and South Forks)
Jim River
South Fork Koyukuk River
Middle Fork Koyukuk River
Sagavanirktok River

On January 28, 1974, based on additional information, the Chief Counsel further concluded that a sufficient factual basis existed to add the following named waters to the list of waters for which permits will be required:

Dietrich River
Hammon River
Slate Creek
Shaw Creek

The EPA, pursuant to §§ 402 and 405 of the Federal Water Pollution Control Act, 33 U.S.C. §§ 1342 and 1345 has authority to issue permits for wastepower discharges. Regulations are found at 33 C.F.R. § 209.120.

Federal licenses

The Federal Communications Act of 1934, 47 U.S.C. § 301, *et seq.*, requires licenses from the Federal Communications Commission, should the applicant's facility require extensive radio communications. Applicable regulations are found at 47 C.F.R. Chapter I.

The Vessel Bridge-to-Bridge Radiotelephone Act, 33 U.S.C. §§ 1201–1208 requires that all large vessels have radiotelephone equipment of a specifid capability. Regulations are found at 33 C.F.R. Part 26. Radio licenses are issued by th Federal Communications Commission pursuant to 47 C.F.R. Parts 81 and 83.

46 U.S.C. §§ 541–713 contains extensive codification of the obligations and duties owed between merchant seamen and the officers and owners of a vessel. The captain, all licensed officers, and 75 percent of the crew of U.S. vessels must be U.S. citizens, 46 U.S.C. § 221, 672(a). Restrictions and qualifications relating to competence and physical condition, including license requirements, are imposed by numerous sections in Title 46 and by Coast Guard regulations promulgated pursuant thereto—46 C.F.R. Parts 10–16. For example, pursuant to 46 U.S.C. § 391(a), tankermen must be specifically certified as being qualified to handle LNG.

46 U.S.C. §§ 11–63, 252, 264 states that no vessel may transport merchandise between points in the United States embraced within the coastwise laws unless it is owned by citizens of the United States, was built in the United States and has been documented under the laws of the United States. Documentations of such vessel must be either by registration or by enrollment and license. Both forms of documentation are administered by the Coast Guard. Applicable regulations exist at 19 C.F.R. § 4.80. Additional requirements for enrollment and license are set forth in 46 U.S.C. §§ 251–335 and 46 C.F.R. Part 67. In addition, 46 U.S.C. §§ 71–83(k) and 46 C.R.F. Part 69 concern the inspection, survey and measurement requirements for documentation.

Federal certificates

Section 7(c) of the Natural Gas Act, 15 U.S.C. § 717(f)(c), requires that a certificate of public convenience and necessity be issued by the Federal Power Commission prior to the construction or operation of any pipeline and related facility for the transportation of natural gas in interstate commerce. The regulations issued pursuant to the Natural Gas Act are found at 18 C.F.R. Chapter I.

The Coastal Zone Management Act, 16 U.S.C. §§ 1451–1464, encourages states to develop, in cooperation with federal and local governments, land and water use programs for coastal waters and adjacent shorelands. Pursuant to 33 C.F.R. § 209.120(g)(17), applicants for federal licenses and permits are required to have certification from the state that the Applicant's activity is consistent with the state's plan.

The Coastwise Load Line Act, 46 U.S.C. §§ 88–88(i), requires each large merchant vessel to have hull markings indicating the maximum depth to which the vessel may safely be loaded, and to abide by the markings. Applicable Coast Guard regulations for assignment of load lines are found at 46 C.F.R. § 2.85–1 and 46 C.F.R. Part 42. Load line certificates are issued by the American Bureau of Shipping. Additional certificates required include:

(*a*) Cargo Ship Safety Construction Certificates issued by the Coast Guard or the American Bureau of Shipping. 46 C.F.R. § 31.40–5;

(*b*) Cargo Ship Safety Equipment Certificates issued by the Coast Guard, 46 C.F.R., § 31.40–10;

(*c*) Cargo Ship Safety Radiotelephone Certificates issued by the Federal Communications Commission, 46 C.F.R. § 31.40–20, and

(*d*) Federal Maritime Commission Certificates of Financial Responsibility. § 311(p) of the Federal Water Pollution Control Act Amendments of 1972, 33 U.S.C. § 1321(p) and 46 C.F.R. Part 542.

Alaska permits

AS 16.10.010 requires a permit for interference with salmon spawning streams or areas.

AS 38.05.330 requires right-of-way easements or permits for secondary roads, ditches and pipelines not subject to AS 38.35.

S 46.03.020 and 46.03.740 require a permit to apply surface oil for dust control or road compacting.

AS 46.03.100 requires a waste disposal permit for discharges into state waters.

AS 46.03.720 requires a permit for the construction or operation of sewage treatment facilities.

AS 46.03.730 requires a permit from Department of Environmental Conservation for use of certain pesticides.

AS 46.15.030 requires a permit from Department of Natural Resources if substantial state waters are appropriated.

11 Alaska Administrative Code (AAC) 12.190 requires a permit for use of explosives.

11 AAC 58.200 requires a permit for roads, trails, ditches, pipelines or similar uses.

11 AAC 58.210 requires special land use permits.

11 AAC 72.050 requires water appropriation permits.

11 AAC 76.540 requires special material use permits.

11 AAC 62.810 requires tidelands right-of-way easements permits.

18 AAC 50.030 requires open burning permits.

18 AAC 50.090 requires a permit for operations in areas involving potential ice fog.

18 AAC 50.120 requires an operations permit for industrial processes involving certain types of air quality emissions.

18 AAC 60.020 requires solid waste management permits.
18 AAC 72.020 requires subsurface waste water discharge permits.
18 AAC 72.040 requires sludge disposal permits.
18 AAC 75.010 requires surface oiling permits.

Alaska certificates

AS 42.06.240 requires a certificate of public convenience and necessity from the Alaska Pipeline Commission, to the extent not preempted by the Natural Gas Act.

18 AAC 70.081 requires a certificate of reasonable assurance of compliance with Federal Water Pollution Act.

The Division of Marine and Coastal Zone Management requires a certificate of compliance with the Coastal Zone Management Act. (The regulations have not yet been promulgated.)

Local permits

Fairbanks Ordinance 49.20.025 requires a special permit for construction in any flood plain area.

Fairbanks Ordinance 45.05.060 requires a burning permit for any burning connected with a construction project.

In addition, the zoning requirements of two burroughs will have to be complied with. Fairbanks Ordinance 49.15.010 governs zoning requirements for the Fairbanks area. The other burrough is North Slope. Presently, the North Slope Burrough ordinances are undergoing revision. When the new ordinances are enacted, it is expected there will be zoning restrictions, as well as other requirements, pertaining to pipelines.

9.1.1 Authorities Consulted

The required list of permits, licenses, and certificates was drawn up by internal research and consultation with others. The basic research material was composed of applicable federal and state statutes and regulations and consultation with outside counsel.

In addition to internal research and consultation, in order to finalize formal application to secure the necessary permits for a surficial reconnaissance it was necessary to contact and consult with several federal and state agencies. The federal agencies were:

United States Department of the Interior
Bureau of Land Management
United States Forest Service, Anchorage
Alaska Command, Military

The Alaskan state agencies were:

Department of Natural Resources
Department of Highways, Central District
Department of Fish and Game

At Valdez, contact was made with the State of Alaska Department of Highways, Valdez District, and at Cordova, contact was made with the U.S. Forest Service Office.

9.1.2 Permits and Authorizations Obtained to Date

On July 9, 1973, Applicant filed applications with several federal and state agencies seeking permits authorizing the surficial reconnaissance of the proposed Alaskan Gas Pipeline route. This surveillance was to consist of two El Paso Natural Gas Company representatives, a construction specialist, a geologist, an environmental specialist, support personnel, and a party chief.

On July 19, 1973, Applicant received from the U.S. Bureau of Land Management a special land use permit authorizing a route reconnaissance for a proposed natural gas pipeline in the utility corridor. The Company had to post a $25,000 bond. The permit was for one year expiring on July 18, 1974. On September 21, 1973, Applicant sent a letter to the Bureau of Land Management informing the appropriate officials that Applicant had completed its reconnaissance of the area, thereby terminating its need for the permit. On August 8, 1974, Applicant received a letter from the Bureau of Land Management informing them that the permit had expired.

On July 19, 1973, Applicant received letter authorization from the U.S. Bureau of Land Management to proceed with the requested study in the Copper River

Valley. This letter was in response to Applicant's notice of request to study the surface geology in Section 17 D–2 lands.

On July 9, 1973, Applicant sent a letter to the United States Forest Service requesting permission to conduct aerial reconnaissance in the Chugach National Forest lands. On July 11, 1973, El Paso received letter authorization to conduct the requested route reconnaissance. This letter also authorized El Paso to land helicopters on the Chugach National Forest lands. The only restriction was that the pilots not disturb the wildlife. The letter contained no specific termination date, therefore, the authorization is still current.

On July 9, 1973, Applicant sent to the Alaska Department of Natural Resources, Division of Lands, a letter identical to the letter sent the U.S. National Forest Service. On July 11, 1973, Applicant received letter authorization to conduct an aerial reconnaissance over state lands. This authorization was good for one year, and terminated on July 11, 1974.

On July 9, 1973, Applicant sent an identical letter to the Alaska Department of Fish and Game. On July 12, 1973, Applicant received letter authorization to conduct aerial reconnaissance of the proposed gas pipeline route. This authorization contained no termination date; therefore, it is still current.

In addition, on July 9, 1973, Applicant sent letters to Mr. Max C. Brewer, Commissioner of the Department of Environmental Conservation, and Mr. Charles F. Herbert, Commissioner of the Department of Natural Resources. These letters advised them of the various agencies that Applicant had been contacting regarding the requested permits and authorizations to conduct the necessary route reconnaissance of the proposed natural gas pipeline.

9.2 COMPLIANCE WITH HEALTH AND SAFETY REGULATIONS AND CODES

This section includes a compilation of federal, regional, state, and local safety and health regulations and codes requiring compliance and pertaining to the construction, maintenance, and operation of the proposed Alaskan Project. Other health and safety standards and codes, such as underwriter codes and voluntary industry codes, are also included. Again, if additional requirements are determined subsequent to Applicant's filing, necessary measures to ensure compliance will be taken.

Federal regulations and codes

The Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. § 1671, *et seq.*, administered by the Secretary of Transportation, permits the Secretary to establish federal safety standards for the construction and maintenance of natural gas pipelines. The actual administration of the Act has been delegated to the office of Pipeline Safety. Subsequent regulations issued pursuant thereto are found at 49 C.F.R. Parts 191–192. (Two of the applicable sections are listed below.) In addition, provisions of the Trans-Alaska Pipeline Authorization Act of 1973 may vest certain safety-related authorities in the Secretary of the Interior.

(a) Title 49, C.F.R. 192 provides applicable standards for the transportation of natural gas and other gas by pipeline, and is based upon the minimum federal safety standards (DOT).

(b) Title 49, C.F.R. 192, Amendment 192–10, Docket No. CPS–14, provides applicable standards for liquefied natural gas systems.

The Occupational Safety and Health Act of 1970, 29 U.S.C. § 651, *et seq.*, administered by the Secretary of Labor, provides for the establishement of certain minimum federal safety and health standards. The regulations issued thereunder are found at 29 C.F.R. Chapter XVII.

(a) Title 29, C.F.R. Part 1910 provides the basic occupational safety and health standards for pipelines. (OSHA)

(b) Title 29, C.F.R. Part 1926 provides the safety and health regulations for pipeline construction. (OSHA)

(c) Title 29, C.F.R. Part 1910.23 provides the health and safety regulations for liquefied natural gas systems. (OSHA)

The Federal Water Pollution Control Act of 1972, 33 U.S.C. § 1251, *et seq.*, controls the disposition of any liquid waste from construction, operation, or maintenance of the Applicant's facility which may reach the natural waters of a state. Regulations issued thereunder are found at 40 C.F.R. Part 125.

The Noise Control Act of 1972, 42 U.S.C. § 4901, *et seq.*, administered by the Environmental Protection Agency, requires that noise emission sources comply with certain standards. The applicable regulations are found in 29 C.F.R. §§ 1910.95, 1926.52.

46 U.S.C. § 391(a) governs the transportation of flammable liquid cargoes in bulk. General requirements are found in 33 C.F.R. Parts 30–40. Each vessel subject to regulation under § 391(a) must be inspected before service and at least every two years thereafter. Coast Guard inspection procedures are found at 46 C.F.R. Part 2.

Under the Ports and Waterways Safety Act, 33 US.C. §§ 1221–1227, the Coast Guard may restrict access to vessels and waterfront areas, and otherwise act to enhance their security, especially if dangerous cargoes are being loaded or unloaded. See 33 C.F.R. Parts 6 and 125 for pertinent regulations. The Coast Guard may require the use of electronic or other devices, may control and restrict vessel movement in almost any manner, may establish cargo handling procedures, and may prescribe safety standards for vessels and certain shore structures.

33 U.S.C. § 471 authorizes the Coast Guard to establish anchorage grounds for vessels in U.S. harbors, rivers and bays and to issue regulations for safe navigation in the vicinity of these grounds. The appropriate regulations are found in 33 C.F.R. § 110.

Title 33, C.F.R. § 209.120(g) (7) provides that the Corps of Engineers is to regulate the construction of piers, docks, and other boat structures.

International Rules of the Road, 33 U.S.C. §§ 1051–1094, apply to vessel navigation on the high seas, and the Navigational Rules for Harbors, Rivers, and Inland Waters, 33 U.S.C. §§ 151–232, apply to vessel navigation within the inland waters of the U.S. The Coast Guard has jurisdiction to enforce both of these navigational rules, 14 U.S.C. § 2, and to prescribe to a limited extent, regulations interpreting and implementing certain of their provisions. For additional relevant statutes, see 33 U.S.C. §§ 171–183, 191–192, 1062–1074, 1075, 1076, 1090.

Title 33, C.F.R. 239, provides U.S. Coast Guard's regulations covering the security of vessels and waterfront facilities.

The Federal Aviation Act of 1958, 49 U.S.C. § 1350 requires consultation with the Administrator of the Federal Aviation Administration for the installation or improvement of airfields or landing areas along the Applicant's right-of-way. Pertinent regulations are found in the Federal Aviation Administration Advisory, Circular No. 70–2, July 23, 1973.

Alaska regulations and codes

AS 18.70.050 and regulations of the Department of Public Safety relate to fire prevention and control during construction.

7 Alaska Administrative Code 14.000 requires approval from the Department of Health and Social Services before entering into contracts for installation or operation of public water systems.

Other industry and underwriter health and safety codes

In addition to the preceding federal and state health and safety regulations and codes, the following standards pertaining to pipelines may apply:

American National Standards Institute (ANSI) B31.8 Gas Transmission and Distribution Piping,

American Petroleum Institute (API),

American Society for Testing Materials (ASTM),

Manufacturer's Standardization Society of the Valve and Fittings Industry (MSS), and

American Waterworks Association.

In addition to the above pipeline standards, the following industrial standards pertaining to LNG facilities will be adhered to:

ACI—315, "Manual of Standard Practice for Detailing Reinforced Concrete Structures,"

AGA—Gas Engineers Handbook—Purging,

AISC—Code of Standard Practice,

American Association of State Highway Officials (AASHO) Specification M145–66—Recommended Practice for Classification of Soils, Soil Aggregate Mixture for Highway Construction Purposes and Standard Specifications for Highway Bridges,

American Concrete Institute (ACI)—Concrete Construction Methods,

American Concrete Institute (ACI)—318, "Building Code Requirements for Reinforced Concrete,"

American Institute of Steel Construction (AISC)—"Specification for Design Fabrication and Erection of Structural Steel for Buildings," American Institute of Timber Construction—"Timber Construction Manual,"

American Welding Society—Standard D1.1—"Structural Welding Code,"

ANSI B31.1 Code for Pressure Piping.
B31.3 Petroleum Refining Piping.
B31.5 Refrigeration Piping.

API—RP2A—"Planning, Designing and Construction of Fixed Offshore Platforms,"

API Standard No. RP-500A—Classification of Areas for Electrical Installations at Petroleum Refineries,

API—RP520—"Design and Installation of Pressure Relieving Systems in Refineries,"

API Standard 2510A—"Design and Construction of LNG Installations at Petroleum Terminals, Natural Gas Processing Plants, Refineries, and Other Industrial Plants,"

ASCE, 1961 Transactions, Volume 126, Part 2, Paper No. 3269—Wind Forces on Structures,

ASME, Section VIII, Div. 1—Boiler and Pressure Vessel,
Diesel Engine Manufacturer's Association (DEMA),
Illumination Engineering Society (IES),
Institute of Electrical and Electronics Engineers (IEEE),
Insulated Power Cable Engineers Associations (IPCEA),
"International Oil Tanker and Terminal Safety Guide" Published by Institute of Petroleum, London, England.
NBFU—National Board of Firefighting Underwriters,
NEC—National Electric Code NFPA, No. 70,
NEMA—National Electrical Manufacturer's Association,
NFPA No. 30 "Flammable and Combustible Liquids Code,"
NFPA 59A "Liquefied Natural Gas at Utility Plants,"
NFPA No. 68 "Explosion Venting Guide,"
NFPA No. 77 "Static Electricity,"
NFPA No. 78 "Lightning Protection Code,"
NFPA No. 87 "Piers and Wharves,"
NFPA No. 321 "Classification of Flammable Liquids,"
NFPA Code 325M "Properties of Flammable Liquids,"
The Metal Grating Institute—Standard MG-1—"Metal Grating," and Uniform Building Code—Zone 3.

9.2.1 Authorities Consulted

The federal, regional, and state safety and health regulations listed above were determined using applicable federal and state statutes and regulations, and consultation with outside counsel.

9.2.2 Procedures to be Followed

Steps will be taken to insure that all personnel associated with the Project will be educated as to the appropriate rules and regulations and the procedures necessary for compliance.

9.3 COMPLIANCE WITH OTHER REGULATIONS AND CODES

The following comprise all other federal, regional, state, and local regulations and codes requiring compliance in the construction, maintenance, and operation of the proposed Alaskan Project.

Federal regulations and codes

30 U.S.C. § 601, *et seq.*, require, unless already covered by an express provision of a federal permit, a separate authorization from the Secretary of the Interior or Agriculture for the use of material from areas on or adjacent to rights-of-way. Regulations issued pursuant to this statute are found at 43 C.F.R., Part 3600.

The Fish and Wildlife Coordination Act, 15 U.S.C. § 661, *et seq.*, 16 U.S.C. § 472, 16 U.S.C. § 551, and 42 U.S.C. § 687 controls construction practices in U.S. Forest Service lands and National Forests.

The Rivers and Harbors Act of 1899, as amended, 33 U.S.C. § 401 *et seq*, requires permission from the U.S. Army Corps of Engineers for bridges, causeways, or other elevated structures over navigable waterways. In this regard, certain regulations are found at 33 C.F.R. Part 114. Similarly, the Transportation Act of 196, 49 U.S.C. § 1665, *et seq.*, may vest some control over the location of bridges over navigable waterways in the Department of Transportation, exercised through the Commandant, U.S. Coast Guard.

33 U.S.C. § 565 provides that Corps of Engineers' approval must be obtained before a private party may improve any of the navigable waters. For regulations, see 33 C.F.R., § 209.120(b)(6), (g)(2), and (g)(8).

Permission for the temporary occupation or use of public works, such as sea walls, jetties, levees, or other works built for improvement of navigable waters or control of floods must be obtained from the Corps of Engineers pursuant to 33 U.S.C. § 408. See 33 C.F.R. § 209.120(b)(5) for pertinent regulations.

46 U.SC § 18 states that every vessel described in the preceding paragraph must have a "home port" in the U.S., the name of which must appear on the vessel's bow and stern, 4 U.S.C. § 46; 46 C.F.R. § 67.13–1, and in the vessel's document of enrollment and license, 46 U.S.C. § 18; 46 C.F.R. § 67.19.

18 C.F.R., Ch. 1, Part 2, § 2.69, Guidelines to be Followed by Natural Gas Pipeline Companies in the Planning, Locating, Designing, and Maintenance of Rights-of-Way and for the Construction of Aboveground Facilities, requires an Applicant and its contractors to comply with certain delineated procedures for environmental enhancement during design, construction, and operation and maintenance of facilities within the jurisdiction of the FPC.

Alaska regulations and codes

AS 16.05.870 requires from the Department of Fish and Game for crossing, using, obstructing or diverting any river, stream or lake.

AS 38.25.020 requires right-of-way leases across state lands, including tidelands and submerged lands.

11 AAC 58.810 requires permission to proceed (from the Department of Fish and Game or the Corps of Engineers) with activities on leased land which would use, divert, obstruct, pollute or change the natural flow of bed of any river, lake or stream, or affect the navigability of any stream.

9.3.1 Authorities Consulted

The above list of other federal, regional, state, and local codes and regulations was prepared using applicable federal and state statutes and regulations and consultation with outside counsel.

9.3.2 Procedures to be Followed

Appropriate measures will be instituted to ensure that all personnel associated with the Project will be educated as to the applicability of the above rules and regulations and the procedures necessary for compliance.

9.4 SPECIAL CASES

9.4.1 Liquefied Natural Gas Facilities

For the applicable standards and requirements governing liquefied natural gas transporting and processing, see the previously cited federal and state codes, regulations, and voluntary industry standards. For the required technical details illustrating the various design features of the LNG Plant, marine terminal and carrier fleet, see Section 1 of this Report. See also Section 11 of this Report for a description of potential hazards associated with LNG storage and transport.

Senator FORD. Senator, you also make the statement on page 7 that perhaps this committee should ask the provincial leaders themselves that the Provinces submit statements to Congress stating what they intend to extract from the pipeline consortium.

This gets into a political arena and it could be, as you say, the ability to tax an outside source and we find that even in this country a good way of taxation. Somebody outside of your State is always easier to apply a State tax.

Taking that fact into consideration and the emotional and political arena that could develop, do you think that the provincial leaders themselves, if they come forward with a statement, that it would be binding under the autonomy that is granted to the Provinces in Canada?

Senator STEVENS. As to binding, I don't think one provincial government can bind another provincial government anymore than one Congress can bind the next Congress. But so far as being sufficient, it would be much better than we have now.

We merely have now a statement that they intend to negotiate with their Federal Government and intend to cooperate. I have to think the best way to maintain good relations with our neighbors, particularly our Canadian neighbors, is to be very precise and exercise some of the leverage that we, too, have on them.

The problem is that this agreement is a one-way street. The only thing in this agreement that benefits the United States is the right of transit across their country. We have granted the right of transit for Canadian oil across our land for quite sometime without extracting anywhere near the concessions in these agreements.

One of the concessions is that Alaskan gas will be served to Canadian communities at U.S. expense en route as the gas comes through northern Canada. We applaud the fact that our Canadian neighbors to the north, actually to our south, southwest—southeast, are going to get gas but we wonder whether it should be at U.S. expense.

We hope that our Alaskan small communities will similarly get the opportunity to have gas. We are told that the cost of takeoffs of this pipeline are substantial and there are some problems about taking off gas for each small community but on the Canadian side, we have made a commitment to take it off for each small community.

When you look at the problems involved in this relationship with Canada, it is a problem that requires certainty and defining our relationships and mutual obligations. There is no question about the obligation of the United States under that agreement or the obligation of the U.S. consumers.

There is serious question about what obligations the Canadian Governments have undertaken other than to prevent discriminatory taxation. Again, as I tell you, if you have a line worth $3 billion in your Province, the portion of this line going through one Province would be about $3 billion, and all other pipelines add up to about $250 million, discriminatory taxation is a weak protection because it would be to the advantage of the people of that Province to have their property taxes assessed against pipeline.

Under those circumstances, ten-elevenths of the revenue of the Province would come from outsiders. No one has really looked at the incentives that are in this agreement for the Canadian governments to in fact extract additional tolls and additional charges from the U.S. consumer, even though they are not discriminatory.

I don't think that we should permit this project to proceed, and again, I am saying so as one who no longer supports any other project. We need a project, we must have this one, and we must have it completed within a reasonable time and at a reasonable cost, both for the Nation and for the State of Alaska.

We have a great fear of delay, and we learned the lesson of delay. Mr. Chairman, I saw friend after friend after friend, small company, go bankrupt after the delay of 4 years in the oil pipeline. Are we to have a similar tooling up now of companies on both sides of the border ready to start construction of this project and have it delayed by Canadian native claims, litigation on either side of the border, refusal of one Province or another to grant a right-of-way?

There is nothing in this agreement that sets any timetable for initiation of construction. It sets a goal for initiation, but it does not say that the pipeline must be started in Canada or any particular portion of Canada by any particular date or that the Canadian Government will take similar action to what is taken by the Federal Government in this country in terms of waiving any national law or requesting any Province to expedite the approvals that are required under Canadian Provincial law.

I do believe that we've got our head in the sand on this project, and the euphoria of international cooperation and good will is going to be lost when it comes down to the nitty-gritty of dealing with local government people.

We should, this Congress should find some way. If nothing else, we should ask these Canadian leaders to provide us with resolutions of their Parliament which indicates a willingness to be bound by the Hydro-Carbon Treaty.

We don't have that yet. We have a statement from the chief executive that they will, subject to negotiations with Ottawa, be bound by the Hydro-Carbon Treaty. They are not yet bound by that treaty.

Senator FORD. You raise another very interesting point, too, Senator, that not only the problems you just related, that there is a good possibility that most of the purchases or a great portion of the purchases to build the pipeline will be expended in Canada.

You refer to that on page 8, I believe, where you say that $7 billion alone in the Yukon and Alberta and the two Canadian steel corporations have been earmarked to produce the pipe for 2,000 miles through Canada.

You also raise a legitimate question of a company here that has the ability to manufacture this pipe, will it be allowed to bid? I think we see here a resource that the United States has in your State subject to many applications of tax, right-of-way, and then not having the ability to manufacture the product that is necessary to build the line and we are financing the whole thing.

Senator STEVENS. We are exporting our financial capability to build this line through Canada. It seems to me that we ought to at least have had some open competition across the border concept. That is not the way the agreement reads. It might be interpreted that way, but that's not what it says.

I think, Mr. Chairman, when we have Youngstown closing down, when we have a projection of a declining economy on our side of the border and we have unemployment problems on our side of the border, to utilize this project on a basis of 80 to 90 percent Canadian content, as the NEB and proponents of the line indicate it might be with regard to the Canadian portion, is just wrong.

If we are to pay for this line, if we are to treat it as if it is a bi-government arrangement, there ought to be a fair division of the employment and manufacturing opportunities involved in its construction.

SENATOR FORD. You also referred to a statement by Dr. Schlesinger that they were counting eight-eighths, and you indicate that one-eighth could be retained by Alaska. What damage to the financial structure of the line would the retention of one-eighth by Alaska be?

Senator STEVENS. If the throughput is only seven-eighths, then only seven-eighths of the volume will bear the full cost of construction and operation and maintenance, and the unit cost has got to go up.

Senator FORD. The unit cost will go up one-eighth compared to the estimate being given to us now by Dr. Schlesinger.

Senator STEVENS. It may go up——

Senator HANSEN. It would go up one-seventh, wouldn't it?

Senator STEVENS. It may go up one-seventh, and it may go up more than that. The problem—it is not a threat, we are not talking about intrastate gas, we are talking about gas produced from lands owned by the State, a State that faces very high costs in all sectors of energy.

We have announced our intention from the very first to utilize this resource in our State if it is at all possible. We now believe it is possible, not only possible but probable and it is the stated intention of our State government, legislative and executive, that this royalty gas will be used in Alaska.

To have the Federal Government calculating the financeability and total financial structure of this pipeline on the basis that somehow or other we will be coerced into sending that gas out permanently, is just wrong.

I think that somehow or other we will be enticed because of some financial arrangements to do so, and there are no enticements that will lead us to change that State policy. It goes back to what the Senator from Indiana was talking about.

If we take the gas, we won't have the revenue. If we don't have the revenue, we can't guarantee any portion of that line based upon projected revenues. We are going to take the gas and use it for the enhancement of our own lifestyle and to improve the way of life of Alaskans that live in the Arctic and in the very rural areas of our State, as well as provide some permanent job opportunities in the interior in the hope of ultimately connecting this gas supply to the gas supply in Swanson River and Cook Inlet so that we can have a protection against disasters such as earthquakes or floods, and have a sharing of supplies throughout our State of this basic energy.

We are not asking for something that is not ours, we own one-eighth of this gas. We own the ground from which it will be produced and we retain the right to take the gas in kind. I think it is very unfortunate that the Federal Government has based its analysis of these projects on the basis that all of the gas will be exported, and it is misleading to the American consumer to think that all of the gas will be exported.

It is like saying to the Senator from Indiana that no matter how big the corn crop is, all of it will be shipped to Alaska. I would assume that if we attempted to legislate or decree that everything of any particular product produced in a State had to be exported, we would have a fight on our hands in any State.

I can assure you that there will be an immense fight from our State if we are denied the right to use our royalty gas.

Senator FORD. I have further questions but I think you have answered most of them and I will yield to the Senator from Wyoming, Senator Hansen.

Senator HANSEN. Thank you, Mr. Chairman. Is it your understanding, Senator Stevens, that the State is willing to participate in the conditioning plant on the North Slope?

Senator STEVENS. The State is unwilling to participate——

Senator HANSEN. Is willing to participate in the conditioning plant on the North Slope?

Senator STEVENS. This is one thing we are exploring and the whole key to this is this conditioning plant and I hope the committee will look at this. Producers of the oil say the gas conditioning plant is not part of oil production. The producers of the gas say the conditioning plant is not part of the gas production. The pipeline company says the conditioning plant is not part of the transmission system.

Yet it is an integral part of all three because unless there is a conditioning plant, the gas cannot be transported. If the gas cannot be transported, the oil associated with the gas it has produced cannot be produced. Gas cannot be transported unless it is in fact conditioned.

Here we have a $2½ or $3 billion plant sitting there that no one wants to be identified with until the purchasers of the gas are identified and in fact guarantee the cost. I have been urging the State for sometime to step in and use its leverage to assure that the gas conditioning plant is built in a timely fashion. I think that's an entirely different matter.

It is an asset entirely within our State and it is necessary for the transportation of the oil and the gas. It is something that we will seriously consider being involved in the financing of.

Senator HANSEN. Do you think it should be an add-on cost, would that be your thought?

Senator STEVENS. It ought to be an ex-wellhead cost. It has to do with transportation and processing and certainly has nothing to do with production.

Senator HANSEN. One final question. What does history tell us about the delays with respect to Canada approving treaties?

Senator STEVENS. The history, Senator, is that unless we are precise in our relationships with Canada, the Provinces will utilize their authority and leverage on the Federal Government in a manner that no one in this country can comprehend that understands States-Federal relationships.

They do not have a constitution, they have the British North American Act. They have in fact a federation of highly independent and powerful Provinces. The Provinces own the public lands. The right-of-way across British Columbia, is primarily on public lands owned by the Province.

Under these circumstances, instead of negotiating 100 percent with the Federal Government in Ottawa as we did, we have urged for a long time that they include the Provincial Governments and this was not done. We have yet to negotiate with the key Provincial Government, British Columbia, which has a history of demanding concessions beyond those which were demanded by the Federal Government in Canada.

I think history, as I point out in my statement, ought to lead us to conclude that there is a potential for delay here and that potential should have been tied down in this agreement in some manner or at the very least, our Government should have demanded that the Provincial Ottawa agreements be entered into before this agreement was signed.

That has not been done and I don't think we have any leverage now, vis-a-vis this line, in the Provinces.

Senator, we have other leverages. We have other leverages vis-a-vis our neighbors and they must be explored and they must be used. We cannot permit the situation to continue which exists in this line and that is that there is every incentive for the Provinces to bring about cost overruns and there is every incentive for this agreement for the builders to prevent them but the builders have no leverage on the Provinces. Only the U.S. Government has the leverage on Canada and its Provinces, in my opinion, and it should be used.

Thank you, gentlemen.

[The prepared statement of Senator Stevens follows:]

STATEMENT OF HON. TED STEVENS, A U.S. SENATOR FROM THE STATE OF ALASKA

Mr. Chairman, I thank you for the opportunity to testify before your committee today and I especially thank you for permitting me to sit with the Members of the Committee during these hearings. As you know, the selection of a route to ship natural gas from my state to the South 48 has been an issue that has been of vital concern to me and to the residents of my state for some time.

We are here to look into the President's decision on the selection of the Alcan proposal. I am sorry that the one alternative, the one option left to the U.S. in case of default by Alcan, has withdrawn its application. If for any reason the Alcan pipeline is not built or completed, I hope we can reconsider an LNG route from Tidewater Alaska to the West Coast.

In any case, Mr. Chairman, I am not here to discuss the all-American concept of transporting natural gas. We in Alaska take some comfort in the fact that the most favorable of the two Canadian routes was selected. The effort by Arctic Gas to ship Alaska's natural resources out of our state without benefit to the people of Alaska was defeated—primarily however, by Canadians. This is a fact we shall not forget.

We won but only if the Congress can be assured that in fact the Alcan pipeline will be built and built without delay. There is a very real possibility that the Alcan pipeline may not be built under the circumstances foreseen by the Administration as expressed by Dr. Schlesinger to this committee yesterday.

In the brief time I have today, let me outline some of my concerns which have led me to question the optimistic timetable for the Alcan Pipeline expressed by Secretary Schlesinger:

Financing

Mr. Chairman, there is serious question that this project can be built with the financing scheme presented in the Presidential Report. The President has predicated his assessment for Alcan's financeability on the assumption that the State of Alaska and the producer companies of the North Slope will participate in quity ownership and debt guarantee of the pipeline. I told Dr. Schlesinger this yesterday and I think it bears repeating today—to my knowledge, the State of Alaska has no intention at this point to participate in any financing of the Alcan line nor have the producers indicated their willingness to participate. In fact a week prior to the President's decision, the Governor of the State of Alaska wrote the President stating the state had no intention of financially involving itself in the Alcan project. The Governor also said that even if he were to change his mind, it was unlikely the legislature would approve such a plan.

Similarly, none of the major producers of the North Slope natural gas have stepped forward and indicated a willingness to participate in either the equity ownership or a debt guarantee of Alcan as is indicated in the Presidential Report.

I personally asked all of the producers of North Slope Gas if they were willing to participate in financing the all-American project and in no instance did I receive any indication that they were willing to do so.

The report's financial analysis concludes that the project can be privately financed. However, when asked, Dr. Schlesinger testified that their conclusion was based on eight-eighths of the gas. He conceded the Administration had not seriously considered the State's options of keeping their one-eighth of the royalty gas within the State. The report may have erroneously concluded that there were sufficient incentives for the State to commit its one-eighth of the gas to the Alcan line. I am told that the State's Commissioner of Revenues, who will testify before the Committee later this week, believes that the inherent risks in the Alcan line, put with the opportunity for gas-based industries within the State, may result in the State's selling only a portion of its gas or none at all.

The residents of my state pay the highest price for the use of natural gas in the United States. I am sure that they cannot be faulted for demanding that the State exercise its options to use one-eighth of the gas for their own use rather than take payment for the royalty gas. So, Mr. Chairman, in view of that possibility, I urge the Committee to take exception to the President's report with respect to the financeability of the Aclan line under a seven-eighths transmission mode,

Mr. Chairman, we all understand that delay will increase the costs of service to the consumer. Financing aside, there are other reasons to believe that there will be substantial delay in the construction of the Alcan pipeline. We cannot permit history to repeat itself. As everyone knows, we suffered from a 4-year delay because of court action and Congressional approval with the trans-Alaska pipeline and it is my hope that this will not happen. But, there are problems with regard to Canadian approval, native claims, and provincial conditions that may well result in untimely delay. Therefore, it is reasonable to assume that there will be cost overruns resulting from actions that the builders of this pipeline will have no control over. Understandably then, the variable rate of return which this report states is the incentive to the builders to keep costs down are only one part of a very complicated problem. Without even questioning the adequacy of the variable rate of return concept, it is questionable whether the incentive to prevent delay will in fact have any impact on those who may cause the delay. In fact, it might be said that the provinces themselves might profit from delay. At this point, it is of little benefit to question the filings of each of the applicants and the interpretation of the Departments which concluded that there would be a 17 cent cost of service benefit should the Alcan be built. But, the President has overlooked the inevitability of LNG facilities being built in Alaska. As you know, we have fifteen highly potential oil and gas basins in Alaska on and off shore. Seventy percent of the outer continental shelf is off Alaska. The estimated potential recoverable gas offshore Alaska alone totals more than 188 tcf. These reserves will have to be transported by LNG. It is reasonable to assume that the American consumer will bear the cost of the LNG facilities which have to be built to transport tidewater gas.

The Alaska Natural Gas Transportation Act of 1976 provided for a limitation of judicial review. The President was authorized to submit a waiver of all laws which he felt need to be waived to expedite issuance of permits for a pipeline. The President's decision requested waiver of only two provisions of Federal law. I suggest this Committee and its competent staff will want to review all other applicable laws to determine if the President's request is all inclusive if we are to avoid delay.

Canadian Federal/Provincial approval

I am surprised, Mr. Chairman, that according to Dr. Schlesinger and the President's report, the only commitment that the U.S. has from the provinces is a "statement of agreement in principal and an offer to 'cooperate' " under the terms of the Hydro Carbon Treaty ratified last month by the Senate. I direct your attention to page 81 of the President's report in which the Province of British Columbia says that the extent of cooperation with any agreement must still be worked out. Dr. Schlesinger said yesterday that the letters of exchange have yet to be completed.

Because of strong provincial autonomy in Canada, this executive agreement is founded on a very thin thread, far too thin and far too weak to assure compliance by the provinces. One need only to look into history.

One such example is the Columbia River Treaty. Following signing of the treaty, British Columbia held up the project until it received nearly a quarter of a billion dollars for a non-related project—the Peace River Dam. It was a classic provincial finesse and a valuable-lesson to be learned by the Americans.

The concern we in the Congress should have is that the provinces have a far greater degree of leverage in extracting concessions from Ottawa than any state has on the Administration in Washington. Regardless of the agreement between the U.S. and Canadian governments, we must realize that it is not binding on the provinces. Ottawa cannot unilaterally preclude the provincial legislatures from exercising their lawful rights to impose direct taxes on this pipeline. And the U.S. would have difficulty holding the Canadian government liable for the provincial right of the provinces to levy whatever lawful direct taxes they wanted on portions of the line that cross their land.

Although I would be glad to discuss this at some length under questioning, there are statements by B.C. to extract every penny possible from the pipeline;

For example, Former Premier and candidate David Barrett told an emergency debate in the B.C. Legislature that it should impose a right-of-way charge of $842 million for crossing B.C. territory and for the resulting "social upheaval" in the northern regions of the province—an area of unsettled native claims. Although the payment of native claims is prohibited, according to Dr. Schlesinger, under the terms of the agreement, the province might levy such a charge as a right-of-way fee or a direct tax, such as a property tax—to pay for the settlement and implementation of Canadian native claims, as it did to pay for another non-related project such as the Peace River Dam in the Columbia River Treaty.

Mr. Chairman, the possibility that another Columbia River Treaty snafu may develop is all too real. The only assurance the Administration has from Canada and the provinces is that they intend to "cooperate". Perhaps, this committee should ask the provincial leaders themselves if the provinces will submit to Congress statements concerning what they intend to extract from the pipeline consortium, and ultimately the American people. Perhaps we should ask them what added charges are they going to put on the line and ask B.C. whether it will pay the settlement and implementation of the Nishga Indians from funds derived from the pipeline.

The sorry thing about this arrangement with our neighbors to the North is that it is in the form of an executive agreement. The largest project ever undertaken by private financing in the history of mankind is submitted not as a formal treaty or protocol for the advice and consent of the Senate as such international agreements are usually handled, but by an agreement between two Chiefs of State.

Labor and Canadian content

Mr. Chairman, I want to briefly touch on another Nettle-some problem that has not been solved but one which may cause a great deal of concern to the American people.

Noticeably absent from the agreement is any mention of "content"—that is the nationality of labor and material used in the construction of the line. Can we assume by omission that the Canadians intend to build their portion of the line lock, stock and barrel? Mr. Chairman, according to the NEB, they are indeed planning just that. According to the Canadian Government, the pipeline through Canada will mean an expenditure of more than $7 billion in the Yukon and Alberta alone. Two Canadian steel corporations, Stelco and Interprovincial Steel, have both been earmarked to produce the pipe for the 2,000 miles through Canada.

Yet, Mr. Chairman, the agreement barely addresses the question of Canadian content, other than on page 60 where it states simply that "each government will endeavor to ensure that the supply of goods and services to the pipeline project will be on generally competitive basis." The question here is whether not the competition ranges across the border opening the contracts to bidding in both nations.

Considering that the Alcan route means an additional deficit in the balance of payments of abuot $10 to $12 billion, American labor at least should have a fair share of those contracts awarded inside Canada. For example, U.S. Steel is building a plant in Bay Town, Texas with the capability of producing 48 inch pipe. Will this plant have an opportunity to bid on the contracts for the pipe? That is a question that is as yet unanswered, in my opinion, Mr. Chairman.

I am also concerned that contractors with extensive experience in building the Trans-Alaskan Pipeline be allowed to participate in the construction of the pipeline that is to be paid for by American consumers ultimately.

I have attempted here to delineate some of the concerns I have and those which are problems to the completion of this line. That there are benefits to both nations from the Alcan line is unquestioned. But I want to caution this committee and the Congress that although this agreement has been touted as an example of international goodwill and cooperation between the United States and Canada, it may very well have the opposite effect. Indeed, unless we are absolutely certain that all the questions have been answered and all the problems solved prior to our approval of the President's decision, then Mr. Chairman, I fear that we are faced with the prospect of having no pipeline at all.

I want to stress that we in Alaska want to work with Alcan to make certain that there is actually a pipeline from the North Slope to the South 48. We will do everything we can to make sure that Alcan is welcomed in our state. But Mr. Chairman, I also hope that we are assured here in Washington that the line will be built.

As I state, I am very concerned about the possibility of delay—delay which the President himself in his letter of transmittal to the Congress said would "greatly increase the total cost of the pipeline."

Mr. Chairman, I ask that the record remain open for my submission of detailed questions to the Administration.

Thank you.

Senator FORD. Thank you very much, Senator.

Under the Rules of the Senate, the committee can stay in session. It has the unanimous consent and therefore we intend to come back. There is a vote on the Senate floor and they will be numerous today.

We hope to come back and start at approximately a quarter of 10. At that time, the Junior Senator from Alaska, Senator Mike Gravel, will be the witness. We will have two witnesses then from—one from Alcan Pipeline and the Alberta Gas Trunk Line Co.

We will recess until approximately a quarter of 10.

[Whereupon, a recess was taken.]

Mr. GARSIDE. Ladies and gentlemen, may I have your attention, please? Because of the situation on the floor, we will have to reschedule this hearing at a later date. I apologize to the witnesses who came from out of town, this was an unforeseeable situation and it is impossible to get Senators here to listen to important testimony.

So the Chairman has asked us to reschedule the hearing until hopefully the week after next. We will be in touch with the witnesses as soon as possible when the hearing is rescheduled. Thank you very much.

[Whereupon, at 10:15 a.m., the committee recessed, subject to the call of the Chair.]

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

TUESDAY, OCTOBER 11, 1977

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 8 a.m., in room 3110, Dirksen Office Building, Hon. Howard M. Metzenbaum presiding.

Present: Senators Metzenbaum, Hatfield, McClure, and Stevens.

Also present: Betsy Moler, counsel; and George Dowd, counsel.

OPENING STATEMENT OF HON. HOWARD M. METZENBAUM, A U.S. SENATOR FROM THE STATE OF OHIO

Senator METZENBAUM. Good morning. The Committee on Energy and Natural Resources is resuming its hearing today on the President's decision to designate the Alcan pipeline project for approval by the Congress pursuant to the Alaska Natural Gas Transportation Act.

Senator Stevens will sit with the committee again this morning to represent the people of his State and will participate in questioning the witnesses.

The committee's hearing on the President's decision began on September 26, 4 days after the decision was sent to the Congress. The September 27 hearing had to be cut short because of the Senate's consideration of the Natural Gas Policy Act. I am pleased to reconvene the hearings and want to thank the witnesses for their cooperation in rescheduling their testimony.

The President's decision and report to Congress on the Alaska Natural Gas Transportation System raises important questions about the viability of the project. While it states that the project can be privately financed, and specifically rejects the prospect of Federal assistance, it makes certain assumptions about the participation of the producers and the State of Alaska. I hope that the President's optimism about the financing is well-founded and that the witnesses will be able to clear up any remaining questions.

I hope the witnesses this morning will address themselves specifically in the manner in which the Alcan pipeline is to be financed.

Today's witnesses are the "winners" in the 3-year old proceedings on this decision. Although Alcan did not file an application before the FPC until July of 1976, the late entry into the competition did not prejudice the result. Alcan has proved its ability to respond to criticism and to changing circumstances. I congratulate the project's sponsors on their successes so far and look forward to hearing today's testimony.

We have Mr. John McMillian, chairman and chief executive officer of the Alcan Pipeline Co., Salt Lake City, Utah, as our first witness.

Good morning. Do you have a prepared statement?

STATEMENT OF JOHN G. McMILLIAN, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, ALCAN PIPELINE CO., SALT LAKE CITY, UTAH; ACCOMPANIED BY BOB BLAIR AND BOB PIERCE, ALBERTA GAS TRUNK LINE CO., LTD.; ED PHILLIPS, CHAIRMAN, WEST COAST TRANSMISSION; MARK MILLARD, VICE CHAIRMAN, LOEB, RHOADES & CO.; AND PAUL MILLER, FIRST BOSTON

Mr. McMILLIAN. Yes. We filed the prepared statement. I would first like to make a statement. I first want to introduce the people with me. I have Mr. Bob Blair, Chairman of Alberta Gas Trunk Line Co., Limited, and Foothills Pipelines (Yukon), Limited, Calgary, Alberta, who will make a brief statement.

We also have with him, Mr. Bob Pierce, with Alberta Gas Trunk Line and Ed Phillips, the chairman of West Coast Transmission which is Mr. Blair's full partner in Canada. We also have with us Mr. Mark Millard, who will join us here at the table. He is vice chairman of Loeb, Rhoades. We also have Paul Miller with First Boston. We also have in the audience Mr. Art Seder, chairman of American Natural Resources Co. and Michigan-Wisconsin Pipeline Co., one of the shipper group. We have Mr. Sy Orlofsky, senior vice president, Columbia Gas Service Corp. with us today and Harry L. LePape, president of Pacific Interstate Transmission Co., Los Angeles. We have Mr. R. Clyde Hargrove, the counsel to the shipper group which consists of the eight companies involved with the project and Cliff Davis, chairman of the Peoples Gas Co., National Pipeline of America.

Senator METZENBAUM. Thank you.

Mr. McMILLIAN. We are pleased to be here today to support the President's decision to name Alcan to bring Alaskan gas to the lower 48. We believe it is a right decision. It is an overland route. It will deliver gas to our market areas much faster and cheaper than the competing projects and will give more reliable service. We think it is also important that the project establishes a better working relationship with Canada which assures the continued export of approximately 2.7 billion cubic feet of gas we now export from Canada today, which is a great help and need to our country.

Senator METZENBAUM. How much gas did you say?

Mr. McMILLIAN. The amount of exports of gas that we have today from Canada are 2.7 billion cubic feet a day. By selection of the Alcan system, we provide the Canadians a route for their frontier gas which will help continue this export of gas to our markets, so this is in addition to the 2.4 billion cubic feet of gas a day we are going to receive from Prudhoe.

Senator METZENBAUM. How much additional gas will this make available to the States?

Mr. McMILLIAN. As far as additional gas, it is just the amount of gas we are going to receive from Prudhoe Bay in Alaska which is 2.4 billion.

Now, several companies, including my own, have export licenses today by which we export 2.7 billion cubic feet from Canada. One of the reasons and advantages for our project is that we give Canada access to their frontier gas that will allow these exports to continue. So this is not what you would call a new supply of gas but it is insuring the present supply of our current exports.

In addition to that, Canada has discussed and will give us, the right to some predelivery of some of their surplus Alberta gas in the early eighties, which will allow us to have predelivery of Alaska gas in effect, but this gas has to be paid back to Canada.

We would like to compliment Dr. Schlesinger and his staff. They had a difficult negotiation to conclude with the Canadians. It was done in a very timely manner. The Canadians worked with Dr. Schlesinger and his staff. Usually negotiations of this type take from 6 months to 2 years. They were concluded in a month's time and they are to be congratulated.

These are some of the points I want to bring out. In conclusion, I want to assure you Alcan will do everything that is reasonable and possible to insure the timely completion of this project for appropriate quality cost control and environmental protection.

This concludes my formal sttement and I will turn to Mr. Blair now, unless there are some questions, and let him make his statement.

[The prepared statement of Mr. McMillian follows:]

STATEMENT OF JOHN G. MCMILLIAN, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, ALCAN PIPELINE CO.

Mr. Chairman, I am John G. McMillian, Chairman and Chief Executive Officer of Alcan Pipeline Company. With me today are the chief executive officers of three of the Canadian companies who will be our partners in the construction and operation of the Alcan project: Kelly Gibson of Foothills (Yukon) Pipeline Limited, S. Robert Blair of Alberta Gas Trunk Line Limited, and Edwin Phillips of Westcoast Transmission Company Limited.

We are very pleased to appear here today to support the President's decision selecting Alcan as the system for transporting natural gas from Alaska's North Slope to the lower 48 states. The Alaska Natural Gas Transportation Act of 1976, which both of your Subcommittees considered last year, established a carefully structured selection procedure. The mandated process resulted in one of the most extensive and detailed inquiries that ever preceded a major decision, and clearly led, we think, to the right decision.

The correctness of the President's selection is evidenced by the findings of the federal agencies which studied the issue as well as by the strong support for Alcan from concerned and informed groups such as shippers, environmentalists, and state regulatory agencies. All of these agencies and groups have concluded that our overland pipeline system across Canada was preferable to a liquefied natural gas system and that an LNG system should only be selected if no acceptable overland transit was obtainable from Canada. The all around superiority of an overland pipeline to a pipeline/tanker system was well established in the lengthy hearing process with compelling proof that a complex multi-mode LNG system would be significantly less efficient, utilize technology untested on the scale required, create substantially greater environmental dangers and impacts as well as require the delivery of unprecedented volumes of energy to the far edge of our country's natural gas distribution network rather than directly to the markets where the gas is needed.

It thus became of critical importance to the selection of a system best suited to our country's needs to work out a mutually beneficial agreement with Canada for a pipeline to transport Alaska gas. Fortunately, Canada's own need for a pipeline from the Far North, described in the Canadian National Energy Board's decision of July 4, 1977, and the long history of cooperation between the United States and Canada made it possible for our two governments to reach an agreement on the Alcan project. The negotiators for each country had the long and close inter-relationship of the two countries in oil and gas matters as a firm foundation on which to build. For example, all oil shipped from western Canada to eastern Canada and large volumes of Canadian oil imports cross the United States by pipeline. Similarly, 40 percent of the gas shipped from Canada's western provinces to its eastern provinces cross the United States by pipeline. Another important aspect of the energy interdependence of our two countries is the Canadian natural gas exports to the United States. Currently, 2.7 billion cubic feet per day—5 percent of total United States' gas consumption—is imported into this country from Canada.

Alcan strongly supports the Agreement in Principle that has been carefully negotiated between the two countries. It exemplifies the historic tradition of cooperation between Canada and the United States wherein each country maintains its independence, but both recognize their interdependence. The Administration has described the details of this Agreement so I will not go over it but will merely reiterate that it very significantly benefits the interests of both countries and represents an unusual negotiating success resulting in improvements over the National Energy Board decision for both parties. This is extremely important since such a mutually beneficial agreement will encourage everyone involved to enthusiastically carry out its terms and expeditiously accomplish its objectives.

The 1976 Act found that the "expeditious construction of the Alaska natural gas transportation system is in the national interest." In view of this need for accelerated action, it is now appropriate for Congress to approve the Presidential decision promptly for the project decided upon has been proven to be in the best interest of our country. If congressional action is put off, construction of the system will be materially delayed and the short-term Alberta supplies which Canada will make available cannot be delivered as now planned for the 1979–80 heating season.

The Alcan project, which will use the Alyeska right-of-way, the Alaska Highway and other existing corridors to minimize environmental damage and to facilitate more predictable and reliable construction and operation, is superior to the alternative LNG system in almost every respect. Let me briefly state some of Alcan's important advantages:

1. *Economics.*—Alcan has a clear advantage in cost of service, which is the measure of the cost of transporting gas. The Administration has estimated that Alcan will have a twenty-year average cost of service of $1.03 to $1.05 per million Btu's in 1975 dollars compared to $1.19 to $1.21 per million Btu's for the LNG option. These estimates include substantial allowance for cost overruns. Alcan's own estimates of its cost of service excluding such theoretical cost overruns are significantly lower, at $.90 per MMBtu.

The Administration's cost overrun estimates appear to be of the same magnitude as the percentage difference between the final preconstruction cost estimates for Alyeska and Alyeska's actual total costs. We do not believe that we will confront cost overruns of the magnitude experienced by Alyeska since our situation differs significantly from that which Alyeska had to confront.

The oil line is located entirely in Alaska and was built almost entirely across virgin terrain. In contrast, the Alcan system can be divided into five segments: Alaska, the Yukon, the rest of Canadian construction, and the eastern and western legs in the lower 48. The Canadian construction and the construction in the lower 48 will be built under fixed price contracts. Construction in British Columbia, Alberta and Saskatchewan will be carried out by experienced pipeline companies, which will be building in their own "back yard." Thus, substantial cost overruns on these three segments are unlikely.

Although overruns are a greater possibility in Alaska and the Yukon, our Canadian partners have construction experience in the Yukon and, both there and in Alaska, we will be able to utilize existing highways and utility corridors, such as the Alyeska corridor. Further, the cost estimates for the Alaska section have been based on Alyeska experience and were not questioned during the Federal Power Commission proceeding. Thus, we believe that careful examination of our project shows that significant cost overruns can be avoided.

Alcan also has a higher Net National Economic Benefit (NNEB), which is a method of measuring the economic benefits and costs to the country from a given project. The Administration has calculated that Alcan will have an NNEB of $5.76 billion; over $1. billion greater than the alternative project. We believe that our NNEB will be even greater, but by any standard, Alcan provides the United States a significant net economic advantage.

2. *Early Deliverability.*—This factor is important in view of the existing natural gas shortage.

We estimate that the Alcan system can begin to deliver Alaska gas by January 1, 1983 if it is expeditiously approved, over a year before an LNG system could be operational. With prompt regulatory action and expeditious construction of the southern end of the Alcan system we should be able to begin deliveries of additional volumes of Canadian gas during the winter of 1979–80 which could be as much as 800 million cubic feet per day.

3. *Continued Canadian Gas Exports.*—The Canadian gas export of 2.7 billion cubic feet per day is approximately 5 percent of United States gas consumption. If Canada is to supply its own domestic markets from presently accessible reserves, it will be required to cut back or eliminate these exports to the United States in the 1980's unless Canada can then transport its frontier reserves. The most effective way for the United States to avoid such cutbacks is to facilitate Canadian access to thee presently inaccessible frontier reserves. Alcan will provide economic transportation for Canada's frontier reserves but an LNG system obviously would not. As a consequence, the 2.0 to 2.5 billion cubic feet per day of Alaska gas delivered by LNG tankers could be more than offset by the loss of 2.7 billion cubic feet per day of Canadian gas.

4. *Gas Distribution and Delivery.*—The Alcan system will deliver gas directly by pipeline to both the western and eastern United States. The President's decision provides for a western leg for the Alcan system to transport Alaska gas directly to the states in the Far West and an eastern leg for delivery of gas directly to the Midwest; from there it can be transhipped to the eastern part of the country. Thus, Alcan will permit equitable and efficient distribution of Alaska gas to all regions of the country.

An LNG system would deliver all of the Alaska gas to the Southern California area. From there it would have to be moved to the rest of the country by displacement, which is the exchange of gas at one location for an equivalent amount of gas at another location. Displacement on such a massive scale is not a satisfactory basis for long-term delivery of Alaska gas reserves.

5. *Environmental Factors.*—The Alcan project was determined to be environmentally preferable to all alternative projects. It assures minimal adverse environmental impacts by utilizing an all-pipeline system which largely follows existing utility and transportation corridors.

All agencies and distinterested parties in the United States and Canada which have reviewed the Alaska gas transportation proposals have recognized Alcan's environmental superiority. The Council on Environmental Quality, in its report to the President, found that Alcan "is the most environmentally acceptable proposal."

We will exert our best efforts to build Alcan as the most environmentally sound project possible. We have met on numerous occasions with the interested environmental groups and have informed them that we will involve them in the pipeline planning and design process at the earliest possible time. In this way, we hope to flag potential environmental problems so that they can be avoided to the fullest extent possible. We believe that this effort together with close cooperation with involved governmental agencies will materially assist our efforts to build a system that minimizes environmental disruption.

It should be noted that the Alcan system developed as a direct result of the National Environmental Policy Act and is testimony to its value. The Council on Environmental Quality stated in their July 1 report to the President:

"The Alcan proposal and the FPC Supplement (environmental impact statement) were direct outgrowths of this federal agency analysis of reasonable alternatives. This development is a tribute to NEPA and illustrates the value of the environmental impact statement process to federal decisionmaking."

6. *Fuel Efficiency.*—The Alcan system will utilize 7.9 percent of the Alaska gas for transportation purposes while an LNG system would require at least 10.9 percent of the Alaska gas for fuel in its pipeline and LNG systems plus fuel for its tankers. This improved fuel efficiency of Alcan on an annual basis is 30 billion cubic feet, sufficient to heat over 245,000 homes. Alcan's effective fuel use can be further substantially reduced by utilizing gas from Alberta for compressor fuel in Canada, a possibility we will be pursuing.

7. *Safety and Reliability.*—An all pipeline system is inherently more reliable than an LNG system, which is subject to a substantial probability of service

interruption. The Council on Environmental Quality concluded that the "analyses of LNG public safety risks on the record are inconclusive." By contract, natural gas pipelines have a long and well established record of being extremely safe.

8. *Financeability*.—The President's decision requires the Alcan project to be privately financed in its entirety. The United States and Canadian governments will not be called upon for financial guarantees. Nor will the consumer have to bear the hypothetical burden of the noncompletion of the project. Instead, other primary beneficiaries of the project will be called upon to provide the necessary financial backing. We believe that Alcan can obtain the necessary project financing from Canadian and United States sources. This pipeline will have a reserve life of at least 25 years which is greater than any other pipeline in this country. With these large proven volumes, the manageability of the technological and engineering requirements of our project and the great need for the energy supplies, there is little doubt that the pipeline will be successfully financed and built.

These are some of the major advantages which make Alcan the best choice for an Alaska natural gas transportation system and which merit prompt approval by the Congress of the President's decision.

In closing, I would like to briefly mention some issues connected with the actual building of the project. We are concerned that the system be built in the most efficient, expeditious and cost conscious manner that is possible. To accomplish this goal, we have reached several conclusions which I would like to share with you. First, we intend to profit from the Alyeska experience. Rational planning and careful sequencing of work can greatly reduce the risk of cost overruns and schedule delays. Further, as I mentioned earlier, we hope to work closely with environmental groups, in order to develop environmentally sound designs and plans at the outset. We will, of course, work closely with the numerous government agencies which will be involved in the authorizing and approval process and cooperate with the Federal inspector of construction, whose role of assuring the building of a sound system was established by the 1976 Act. We are also preparing to institute and diligently pursue a positive program of assuring minority business enterprises participation in provision of material and construction.

Alcan welcomes the coordinated federal oversight of project management and construction that has been proposed to avoid needless construction delays and cost increases for we strongly believe that this coordinated regulatory approach recommended in the Presidential decision is essential to minimize cost overruns and insure the lowest possible cost of service price to United States consumers. We point out that as experienced members of the regulated gas industry, we are comfortable working with close regulatory supervision and that the United States-Canadian agreement provides us with powerful incentives for effective project cost control. Furthermore, we believe that this required close government-industry cooperation will materially assist us in obtaining project financing.

In conclusion, let me assure you that Alcan will do everything reasonably possible to insure the timely completion of the project with appropriate construction quality, cost control and safety and environmental protection.

I will be happy to answer any questions you may have.

STATEMENT OF S. ROBERT BLAIR, PRESIDENT AND CHIEF EXECUTIVE OFFICER, ALBERTA GAS TRUNK LINE CO., LTD., AND FOOTHILLS PIPELINES (YUKON) LTD., CALGARY, ALBERTA, CANADA

Mr. BLAIR. There was a general opening statement prepared in behalf of the operating companies and perhaps rather than read it—it consists of five pages—I might remark a little bit more on the subject of our position or would you like me to read the statement?

Senator METZENBAUM. I think we understand the advantages and the need for a pipeline. We will insert your statement in the record. I think we are somewhat interested in who is Alcan. We know the names. We would like to know what this total project will cost. We would like to know what each of the partners is going to put into the project. We would like to know where the financing is going to come from, how it is going to come, and what assurances you have the producers will or will not participate in the project. There seems to be some confusion about that.

I think we would like to know what this business project is all about in order that we may evaluate it in its light of success as well as its impact on the American economic picture.

Mr. BLAIR. May I open up then. I will open up in respect to the project that is located in Canada. There are two main gas pipeline companies operating in western Canada.

I am the president and chief executive officer of one, the Alberta Gas Trunk Line Co. Seated directly behind me is Mr. Edwin Phillips, who is the president and chief executive officer of the other, which is West Coast Transmission Co., Ltd.

I am speaking for the moment for our Canadian companies jointly. They can join in any of these answers if you wish.

Our two companies operate gas transmission systems which are relatively large. Between us, we operate about 8,000 miles of pipelines. In respect to quantities of gas moved, my own company moves 1.9 trillion cubic feet a year, which would rank itself somewhere in the top two or three companies in North America measured by that standard.

We build quite considerable quantities of new pipeline each year. Our program this year is about 700 miles. West Coast builds on occasion some hundreds of miles per year and we finance these extensions of our gas transmission services regularly and principally in the Canadian capital and in terms of long-term debt in the United States market. Our financings run to several hundreds of millions of dollars a year between these two companies.

For this project which will require about three and three-quarters of a billion dollars of capital investment in Canada, a financing plan has been developed consistent with our current and past experience of the best manner to finance such installations and consists also of the projections for the Canadian and United States' capital markets in the years we are anticipating.

Our financial advisers in the investment community are the firms of Pitfield-McKay and Dominion Securities, which are two of the best firms in Canada for such advice and our bankers are the Imperial Bank of Commerce, the Bank of Nova Scotia, and the Bank of Montreal, which are three of the five largest banks in Canada, which would also rank considerably internationally in the scale of their operations.

I think in speaking to the financing, since emphasis is being put on that this morning, I would turn particularly to Robert Pierce, who is sitting on my left, and who is executive vice president of Alberta Gas Trunk Line Co., who also was the officer of a Canadian company, the most senior such officer in all of the testimony that has been put in for our Canadian companies in these various regulatory and inquiry proceedings.

I will ask him to speak with respect to financing. On his left is Paul Miller who is President of the First Boston Corp., who has managed by considerable margin the placement of securities, Canadian securities, in American markets in recent years.

Senator METZENBAUM. Mr. Blair, the financing will be in one whole project you are a partner in, the total Alcan Pipeline Co. Will the ownership of the pipeline company own the Canadian part as well as the United States part or will there be separate ownership?

Mr. BLAIR. We will have separate ownership. Within Canada, the ownership arrangement is this: one single company, the name of which is Foothills Pipelines (Yukon) Ltd., has been designated by the National Energy Board which it approved to control the ownership of the various segments of pipeline which are needed in Canada.

The proposal is it will control that ownership to a series of subsidiaries, subsidiary companies, which will operate in the different Provinces and Territories in which the pipeline is located in Canada, employing the local gas pipeline transmission, to build the pipeline, so we may optimize the efficiency of using the people and the structures that are in place there with a single overall ownership under that Federal company which will be a separate company from the Alcan Pipeline Co.

Perhaps the most efficient way for us to answer would be in terms of financing would be to put the microphone in front of Robert Pierce and ask him to coordinate the financing question between Paul Miller and myself.

[The prepared joint statement of Messrs. Blair, Gibson, and Phillips and the joint statement of Messrs. Lepage and Orlofsky follow:]

JOINT STATEMENT OF S. ROBERT BLAIR, PRESIDENT AND CHIEF EXECUTIVE OFFICER, ALBERT GAS TRUNK LINE CO., LTD., AND FOOTHILLS PIPELINES (YUKON) LTD.; KELLY H. GIBSON, CHAIRMAN OF THE BOARD, FOOTHILLS PIPELINES (YUKON) LTD.; AND EDWIN C. PHILLIPS, PRESIDENT AND CHIEF EXECUTIVE OFFICER, WESTCOAST TRANSMISSION CO. LTD.

My name is Robert Blair and I am President of The Alberta Gas Trunk Line Company Limited (AGTL) and Foothills Pipelines (Yukon) Ltd. (Foothills). With me today are Kelly Gibson, Chairman of Foothills, and Edwin Phillips, President of Westcoast Transmission Company Limited (Westcoast). On behalf of each of our companies, I would like to express our appreciation for the opportunity to appear before you today and provide our views on the pipeline system which has been recommended by President Carter and Prime Minister Trudeau for the transportation of gas reserves from Alaska and Canada's Mackenzie Delta.

As the Canadian sponsors of the Alaska Highway project, we are obviously delighted with the President's decision, as well as the Principles of Agreement which has been negotiated between our two countries. After years of study and intense hearings, it is rewarding to be on the threshold of a solution which will provide substantial benefits to both Canada and the United States, and continue our long tradtion of cooperation in matters of mutual economic interest.

John McMillian and others have described the basic advantages of our project to the United States, and we will not reiterate these points. Instead, we will provide you with our companies' views as to what Canada has to offer in this project and what it has to gain. At the conclusion of our prepared statement, my colleagues and I will be happy to respond to your questions.

PROFILE OF THE CANADIAN SPONSORS

Let me begin by briefly describing the role which each of our Canadian companies will play in the Alaska Highway Project. In addition, I would like to tell you something of our background and experience. As you will see, our companies are not newcomers when it comes to the construction and operation of gas pipeline in the far north.

The Canadian portions of the Project will be under the control of a single corporate entity, Foothills Pipe lines (Yukon) Ltd. Foothills (Yukon) is presently owned equally by two of Canada's largest gas transmission companies, AGTL and Westcoast. An agreement has been announced that the third major Canadian transmission company, TransCanada Pipelines Limited, will take a twenty percent position in the company at a future date.

One of the strong features of our Project is that in each main area of western Canada the pipeline will be constructed by the gas transmission company which has already performed major construction responsibilities locally. Thereby, the section in northern British Columbia, to be owned by Foothills Pipe Lines (North B.C.) Ltd., will be constructed by Westcoast; and similarly, the pipeline across Alberta, to be owned by Foothills Pipe Lines (Alta.) Ltd., will be constructed by AGTL and so on. This arrangement provides the ideal combination of ownership and regulatory control being integrated under the single parent company while for physical construction the management resources and field experience of the local operator will be applied in entirety. For the one area in which there is no established operator yet, the 500 miles through the south-western Yukon, we are establishing a complete construction management team.

These arrangements should have substantial advantage toward the most efficient project management and cost control.

Together, Westcoast and AGTL have constructed approximately 7500 miles of gathering lines and large diameter mainlines in western Canada. This construction has been accomplished in all types of weather and all types of terrain, including some discontinuous permafrost. Through it all, however, we have established a consistent record of completing projects on schedule and typically within five percent of the budget.

In terms of size, AGTL now ranks among the top two or three when North American pipelines are rated according to the volumes of gas they transport. Together, Westcoast and AGTL transport nearly 90 percent of the gas produced in Canada and handle virtually all of that gas which is exported to the United States. At the present time, we are responsible for transporting approximately 2½ billion cubic feet of gas per day which eventually is consumed in markets across the United States. This volume exceeds the amount of gas expected from Prudhoe Bay.

Both of our companies are actively involved in gas pipeline construction. In some years, we have added as much as 750 miles of pipeline to our system in western Canada. As a result, rather than rely upon outside consultants, we have built up our own engineering and construction management organizations so that we now have a most competent and experienced engineering units, actually the largest in Canada.

Also, of course, the addition of TransCanada Pipelines, the largest gas transmission operation in Canada, and Alberta Natural Gas Company will add further strength.

I emphasize the size and experience of these Canadian companies because, in my judgment, this will provide strength to the Project. Our Project construction will simply be an extension, albeit a large one, of the planning, financing, and installation work which we accomplish year after year with the present infrastructure. This is part of the base for our confidence that we can meet the schedules and capital cost budgets which have been published.

BENEFIT TO CANADA

In Canada this particular Project is seen, both by our industry and our Government, as rather special in that it results in commercial benefits to industries and companies in both the United States and Canada, and also in political benefits in both countries. This combination does not exist often and there is a really strong enthusiasm now inside Canada for securing those benefits in the Canadian interest. The National Energy Board in Canada has defined this particular Project as in the Canadian national interest; and, as has been well publicized, the Prime Minister of Canada has declared expressly that the Government finds that it will serve our national interest.

One of the benefits to Canada is that the Project will provide for a manageable and economical connection of gas reserves which have already been identified in the Mackenzie Delta and of the potential additional gas resources in the Beaufort Basin. Recognition of this should encourage continuing, gradual development of the gas discoveries which have already been made in those areas. Another area of substantial benefit in Canada is derived from the employment and manufacture that will go into the construction of the Project.

Also, this Project will produce a substantial flow of revenue through our companies to the public of Canada as taxes and also eventually as capital dividends for reinvestments and to our shareholders. Importantly, all of these benefits can be achieved with acceptable effects on environmental and social interests in Canada. The Canadian Government agencies, inquiries and independent societies and panels have concluded generally that the Alaska Highway route is preferable to any alternative and is environmentally acceptable. Similarly, our Government has concluded, after public inquiries, that our Project is acceptable in terms of social and local and national economic impacts.

ALBERTA SURPLUS GAS

At the present time, there are approximately 20 trillion cubic feet of proven, but unconnected, gas reserves in the conventional producing areas of Alberta. The National Energy Board, with our Government's approval, has suggested that some of this surplus could be made available to United States' consumers in the near term and ultimately repaid when Alaskan gas comes on stream.

Our companies fully endorse this exchange arrangement. In fact, one of AGTL's subsidiaries, Pan Alberta Gas Limited, has already entered into a five-year contract with Northwest Pipeline Corporation for the sale of up to 800 million cubic feet per day. By "prebuilding" certain facilities, this gas could be in full flow by the end of 1979, at least three years prior to the advent of Alaskan gas. Prebuilding the downstream project would also be positive in terms of overall Project management and procurement.

TESTIMONY OF MESSRS. H. L. LEPAPE, AND S. ORLOFSKY ON BEHALF OF U.S. GAS COMPANIES [1] SUPPORTING THE ALCAN PROJECT

As these subcommittees know, the group of companies for whom we appear were members of the Arctic Gas consortium for several years. Previously, Arctic Gas was one of the three applicants (and the first applicant) for an Alaskan North Slope gas transportation system. Today we appear in support of the Alcan Pipeline proposal which the President has recommended to the Congress for approval. It was our thought that these subcommittees would be interested in knowing why this group, who had for so long supported Arctic Gas, elected to support Alcan, and their intention for future participation in that project.

On July 4, 1977, the Canadian National Energy Board denied approval of Arctic Gas' Canadian components and issued approval to Alcan's Canadian components. Thereafter, these eight U.S. gas companies jointly undertook a new appraisal of the relative merits of the Alcan and El Paso projects. It was the unanimous view of these companies that they had a responsibility to their customers, and to the public at large, to advise them of their views as to the transportation system which would best serve the needs of the United States to effect delivery of the Prudhoe Bay gas.

The companies, of course, had the advantage of long participation in regulatory proceedings involving all projects proposed, and possessed an extensive body of knowledge and data concerning all details of the rival El Paso and Alcan projects. They had already conducted extensive investigations of those systems and had in place highly sophisticated computer programs to permit rapid evaluation of the economic performance of those systems. As a result of the reappraisal, the eight companies unanimously elected to support Alcan because it far better serves the needs of the gas consuming public than does the El Paso proposal.

Perhaps the primary reason for the decision in favor of Alcan was economic. Rather than simply relying on the figures compiled by the other applicants themselves, or by the agencies of any government, the eight companies reestimated the cost of service of each system on the basis of their own estimates of what

[1] Pacific Gas and Electric Company serving Northern California: Pacific Lighting Corporation subsidiaries serving Southern California; Northern Natural Gas Company serving the Plains areas; Natural Gas Pipeline Company of America, a subsidiary of Peoples Gas Company, serving Chicago and the Midwest; Michigan-Wisconsin Pipeline Company, a subsidiary of America Natural Resources Company, serving Detroit and the Midwest; Panhandle Eastern Pipeline Company serving throughout the Midwest; Texas Eastern Transmission Corporation serving the South, Appalachia and to New England; Columbia Gas Transmission Company, a subsidiary of the Columbia Gas System, serving from Ohio to the Eastern Seaboard.

they expected those costs to be. This reevaluation indicated significantly lower costs for the Alcan system than for the El Paso proposal. The probable margin of difference was in the order of $.45 per MMBTU delivered to markets in the lower 48 states on a 20-year national average in 1975 dollars.

A second critical factor was the importance of retaining Canadian gas exports to the United States at the current level of such exports, or at least at the maximum level possible. It is obvious that the prospect of continuing Canadian exports to the U.S. is directly related to a level of gas supply in Canada in excess of Canadian domestic requirements. All the studies available to us indicate that maintenance of such a supply over the long term is dependent upon the addition of so-called "frontier gas" to Canadian supplies. In our view, the only frontier gas presently identifiable which can be brought to market within the needed time frame is the Mackenzie Delta gas.

The Alcan system makes it possible to attach the Mackenzie Delta gas supplies for Canadian use within the near term and on a basis sufficiently economical to be feasible. The El Paso proposal offers no prospect of an economic connection of the Canadian frontier reserves. Approval of El Paso, therefore, would clearly jeopardize the continued maintenance of Canadian exports at present levels, and those levels are now in excess of the volume expected to be received from Prudhoe Bay. Therefore, El Paso's proposal for shipment of Alaskan gas without preservation of Canadian exports could result in a net loss rather than a net addition of gas to U.S. supplies. We deem this situation critical to the United States as a whole, and extremely critical to those areas of the country which rely directly on Canadian gas for large portions of their supply. Furthermore, Alcan's fuel requirements would be substantially less than those of El Paso. This, too, would provide a further supply margin in favor of the Alcan project.

Another matter of concern with the El Paso project is the problem of receipt and delivery of gas in the lower 48 states. The question of a regasification site in California appeared to us to be largely within the control of the state of California. Even after the siting problem in California is resolved, there are further problems associated with the delivery of that gas from California throughout the remainder of the lower 48 states. The El Paso proposal for construction of certain facilities in Texas and California, and thereafter for use of excess capacity in existing pipelines from Texas through the rest of the 48 states is subject to great uncertainty. While both Arctic Gas and El Paso were able to construct theoretical delivery methods for delivery of this gas to the mid-west and east by use of excess capacity within and from Texas, these theoretical studies necessarily were based on assumtions as to the volumes of gas which would otherwie be moving in such pipelines. It is impossible for anyone to verify today with any degree of accuracy what the actual excess capacity of those pipelines, if any, will prove to be some years hence when the Alaskan gas begins to flow. The recent public announcement of purchases of large quantities of gas from Mexico proves this point. The expected Mexican gas supply is of such a magnitude that it will completely absorb all the excess capacity now present in those existing lines in south Texas and along the Gulf Coast that El Paso had proposed to use for delivery of Alaskan gas. It would, therefore, be necessary for El Paso to build new facilities different from and in addition to those presently proposed by El Paso in order to move gas from Texas at least as far as Louisiana.

It is not possible at this time to determine precisely what facilities would be best suited to this purpose. But it is clear, observing the extensive distance from Texas to points within Louisiana, that large additional sums of money over and above those contemplated by El Paso would be necessary to effect this delivery. The eight companies strongly prefer the more direct form of delivery offered by the Alcan system with its eastern and western legs.

With the enactment of the Alaska Natural Gas Transportation Act of 1976, Congress wisely chose to insist on the certification and construction of the facilities necessary to assure contemporaneous, direct pipeline delivery of Alaskan North Slope gas both east and west of the Rocky Mountains. The Alcan project, with its eastern and western legs, complies with this legal requirement for contemporaneous direct delivery. Both eastern and western legs are integral parts of the Alcan proposal. The elimination of either leg would impair the efficiency of the total transportation system; without the western leg, for example, the resulting inefficiencies would increase transportation costs, adversely impact the environment and result in the loss to the U.S. consumer of over 480 trillion BTU of natural gas over 20 years; without the midwestern and eastern leg, the same problems posed by the El Paso proposal would be presented.

We are pleased that the President has recommended contemporaneous certification and construction of both the eastern and western legs of the Alcan project. If short term excess supplies of gas in Alberta are made available to U.S. customers on satisfactory terms and conditions, prebuilding of portions of the eastern and western delivery legs, if economically and financially feasible, could provide direct access to this short term supply.

After arriving at our unanimous determination to support the Alcan project, the eight companies approached Alcan to offer their support and cooperation. Despite the highly contested nature of the previous adversary proceedings in which we had been engaged with Alcan, we are pleased to state that we were most cordially received and welcomed by Alcan on a basis contemplating a partnership. Since that time, we have actively worked with Alcan in close liaison at multiple executive and technical levels. Through the creation of an executive committee, we have been kept fully advised of Alcan's activities and in turn have advised and counseled Alcan. We foresee no undue difficulty in perpetuating our joint participation with Alcan on a permanent basis as partners in the operation and ownership of the transportation facilities in Alaska. The facilities in the lower 48 states will be owned and operated by the various members of our group located in the geographical areas to be served. It is our intention to participate, to the extent we are prudently able to do so, in the equity financing of Alcan's Alaskan facilities as well as in the equity financing of lower 48 facilities. Obviously, terms and conditions adequate to attract equity investment must be allowed by the regulatory authorities in order to permit us to make such investments.

One final point: it is quite obvious that no facility to transport Prudhoe Bay gas to the lower 48 states can actually be financed and constructed by anyone until the Prudhoe Bay gas is sold to buyers in the lower 48 states. Financing is completely dependent upon final identification of the buyers and the volumes which will be required by each; certain refinements in lower 48 and Canadian facilities will be needed to accommodate precise volumes of gas to be delivered to precise delivery points, and these refinements must await firm identification of all of the purchasers and the volumes purchased. There are obviously limits to the amount of money which any of these companies can justifiably risk before they have obtained contracts for the purchase of gas, and before permanent financing has been committed. Each of these companies individually is not only willing, but anxious to negotiate for the purchase of Prudhoe Bay gas at the earliest opportunity. We trust that opportunity will be afforded to us promptly upon conclusion of Congressional action on the President's recommendation.

Thank you for your consideration. We welcome any questions members of the subcommittees may have.

Senator METZENBAUM. Do I understand Mr. Pierce will testify with respect to the financing in Canada, the Canadian portion?

Mr. BLAIR. That is correct.

Senator METZENBAUM. Then maybe we ought to go back to Mr. McMillian to see what we are going to do about the U.S. portion of the financing. I need to get an overview of what this economic picture looks like and what they are being called upon as a company to do and what Alcan itself is doing, what the producers are doing. I have never been quite able to understand this.

Mr. MCMILLIAN. To briefly summarize this, I think what you are asking has been summarized by the President's Report on page 108.

Senator METZENBAUM. Would you put the microphone closer, please?

Mr. MCMILLIAN. The financial structures, the financial requirements of the different companies are outlined on pages 108 and 109 of the President's Report. It is divided into five different groups on pages 108 and 109. The first group is Alcan Pipeline. That is over 700 miles of pipeline through Alaska. That amounts to about $3.5 billion. The companies that would be involved in this section of the line will all be American companies. There will be our company, and we have had several other companies indicate support for us and a willingness to join in the construction of this portion of the line.

I will name the names of these companies: American National Resources Co., Columbia Gas Transmission Co., Pacific Interstate Trans-Mission Co., Pacific Gas & Electric Co. of San Francisco, Peoples Gas Co., Panhandle Eastern Pipeline Co., Northern Natural Gas Co., and Texas Eastern Transmission Co., which are eight of the largest transmission companies in the United States.

The exact equity distribution of this portion of the system is yet to be determined, because the gas contracts have yet to be executed by the producers, and the amount of gas to be purchased by each transmission company will be a function of the amount of equity each one of these companies will have in this section of the line.

Senator METZENBAUM. How much equity money will be going in?

Mr. McMILLIAN. Seventy-five, 25 percent, approximately $180 million for the Alcan or Alaskan section of the line.

Senator METZENBAUM. Would you explain to us, when Senator Stevens—he indicated the producers have absolutely no intention of participating in the financing of the project. These companies you just mentioned, you would not consider them the producers?

Mr. McMILLIAN. No. These are the transmission companies regulated under the Natural Gas Act that have responsibility to transport this gas. He is talking about using companies, Exxon, Arco, Sohio, BP, those type of companies. Those producers have not testified before any committee in Congress. They are supposed to be before the House committee on Friday.

Now, we think—on that portion, I would like to introduce Mr. Millard, and let him make a brief statement as to how we plan to obtain these dollars and from what sources and how some of these things can be done. This is Mark Millard, of Loeb Rhoades.

Mr. MILLARD. I did not come with a written statement because I though my function would be primarily answering questions. But if I may contribute to clarifying the issues involved, I would like to sketch in a few words the overall structure of this financing.

Let me say first that it is project financing, which is a technical expressiot meant to mean that it is not the credit of existing entities which stands behind the debt of the new company but the business, the economic viability of the project itself.

Now, when it comes to the architecture of this financing, we have to use a number of technical terms. All estimates in this world of inflation, obviously, are of limited validity. Hence you have to define the figures with which you work. Our most usual estimate of the cost of the investment for this company which was used in most of the proceedings in this case, is a figure of $9.6 billion, which is essentially 1975 costs escalated at 5 percent with a small contingency reserve of also approximately 5 percent. These $9.6 billion are divided between United States and Canada in such a way that the Canadian section is approximately $3.9 billion, and the balance is United States. The source of funds is distributed in a different way. A substantial part of the investment in Canada will be financed in the United States, although for the two main lines the investment costs as between Canada and the United States is about equal.

As to the source of funds, the United States will contribute the lion's share; all but, if I remember correctly, $1½ billion will be raised in the U.S. market. The Canadian contribution is $800 million, which is $500 million in bank loans and $300 million of long-term debt. All of the balance comes from the United States.

The majority of the investment is made in the United States. As always in the development of Canadian facilities, the U.S. capital market will have to provide a large part of the needed funds.

Now, so far as equity is concerned, Mr. McMillian has already pointed out that the equity which will be subscribed by the Canadian pipeline companies and by the gas pipelines transporting the gas in the United States and will amount to 25 percent of the total.

Senator METZENBAUM. You are saying the pipeline companies, the common stock being sold, will that be bought by pipeline companies, paid for by them, or would it be by way of public offering?

Mr. MILLARD. The thinking has always been in terms of the pipeline companies buying all of the stock. However, as Mr. McMillian said, so many issues underlying and conditioning the final form of the financing, issues which belong in the purview of government, are still unresolved, that it would be, I think, premature to try to answer all questions in a completely definitive form with respect to detail. It is conceivable that some part of the equity will be sold to the public. But this was not a part of our plans.

Senator METZENBAUM. Are the pipeline companies in a position to provide over $2 billion of equity funds?

Mr. MILLARD. Yes, sir. I think the easiest way to look at it is to look separately at the Canadian side and the American side. The three companies active in Canada, the three parent companies—Mr. Blair's company, Mr. Phillips' company, and Trans-Canada—are certainly able to provide the $800 million. Since it is anticipated that the majority of the great gas transportation industry of the United States will participate as shipper-owners in the American property, it is equally easy to assume that they will be able to subscribe for the issue of $1.2 billion of common stock.

Senator METZENBAUM. Under what circumstances would there be a public stock issue?

Mr. MILLARD. Your question is speculative. I must answer in the same way.

Senator METZENBAUM. My question isn't speculative; maybe your answer will be.

Mr. MILLARD. I am sorry and you are right. At the time when financing is finalized, which is the condition making a public sale possible, we would welcome the sale of a part of the stock to the public. Essentially this is a public service company, and I think its nature can be emphasized if the public has a stake in it.

Senator METZENBAUM. Have the companies made any economic projections with respect to the operation of the Alcan pipeline?

Mr. MILLARD. Yes, sir.

Senator METZENBAUM. Would those be made available to the committee?

Mr. MILLARD. Yes, sir. I will arrange it. As you know there has been a great deal of paper in these proceedings. We have ample documentation on all of these questions. I will arrange for it to be delivered to you.

Senator METZENBAUM. I think the committee will appreciate getting your 5, 10, and 20 year economic projections with respect to the Alcan pipeline.

[Due to the voluminous nature of the material submitted only the cover letter and summary charts are reproduced here. The rest of the materials are retained in committee files:]

ALCAN PIPELINE CO.,
Washington, D.C., October 21, 1977.

Hon HENRY M. JACKSON,
Chairman, Energy and Natural Resources Committee, U.S. Senate, Dirksen Senate Office Building, Washington, D.C.

DEAR SENATOR JACKSON: Pursuant to Senator Metzenbaum's request, in the Energy and Natural Resources Committee hearings, October 11, 1977, of Mr. Mark Millard concerning financial projections for the Alcan Project, we are submitting copies of pro forma financial statements, cost of service and resulting unit cost per million Btu. The information contains 20-year cost of service information for all segments of the Alcan system based on the assumptions underlying the negotiations between the Canadian and U.S. governments and certain select assumptions defined by the White House Staff for use in preparing the comparative studies. You will note that a 5 percent escalation factor was assumed as directed by the White House Staff. You will note that the unit cost per million Btu contained in this study varies from that shown in the President's message to Congress. This results primarily from the White House Staff assuming a cost overrun level not inherent in Alcan's studies.

If we can be of any assistance in interpreting any of the information or answering questions about the study, we would be happy to do so.

Sincerely,

DARRELL B. MACKAY,
Vice President.

ALCAN PROJECT—NEGOTIATED CASE—CASE NO. 7a: NATIONAL AVERAGE ANNUAL UNIT OF COST SERVICE

[Dollars per MMBTU]

	Escalated [1]	Discounted [2]		Escalated [1]	Discounted [2]
1983	$2.29	$1.59	1994	$1.79	$0.73
1984	2.21	1.46	1995	1.77	.68
1985	2.24	1.41	1996	1.75	.64
1986	2.17	1.30	1997	1.74	.61
1987	2.11	1.20	1998	1.74	.58
1988	2.06	1.12	1999	1.74	.55
1989	2.00	1.03	2000	1.73	.52
1990	1.94	.96	2001	1.75	.51
1991	1.89	.89	2002	1.73	.47
1992	1.85	.83			
1993	1.82	.78	20-yr average	1.92	.89

[1] Costs (including fuel) escalated 5 percent per year from mid-1975 in computation of cost of service.
[2] Unit cost of service figures discounted in mid-1975 at 5 percent compounded annually.

ALCAN PROJECT NEGOTIATED AGREEMENT VERSION OF COST OF SERVICE

	Alcan Pipeline Co.	Foothills-Yukon section	Foothills Dawson/Whitehorse link	Westcoast-northern section	AGTL (Canada)	Alberta Natural Gas	Foothills-Saskatchewan section	Lower 48 facilities	Subtotal	Fuel costs	Total cost of service	Volumes in MMBTUS	Unit cost of service (per MMBTU)
1983	$768.1	$343.3	------------	$252.2	$235.8	$16.1	$40.8	$395.3	$2,051.6	$90.6	$2,142.2	935.495	$2.290
1984	739.9	330.1	------------	240.9	224.7	15.3	39.0	387.8	1,977.7	93.9	2,071.6	936.116	2.213
1985	710.8	277.7	$116.8	185.5	188.5	14.7	37.5	382.0	1,913.5	133.7	2,047.2	914.654	2.238
1986	676.7	272.8	112.1	180.9	183.1	14.4	36.6	376.0	1,852.6	138.0	1,990.6	916.004	2.173
1987	635.7	269.7	108.6	177.6	179.5	14.1	36.1	366.1	1,787.4	145.5	1,932.9	915.858	2.110
1988	598.2	267.5	106.5	175.0	176.4	13.8	35.6	361.9	1,734.9	151.2	1,886.1	916.698	2.057
1989	562.9	265.5	105.3	172.5	173.7	13.6	34.9	347.8	1,676.2	157.1	1,833.3	917.355	1.998
1990	530.3	262.5	104.3	169.2	170.1	13.4	34.4	335.3	1,619.5	163.7	1,783.2	918.012	1.942
1991	499.7	259.6	103.2	166.3	166.5	13.0	33.6	323.9	1,565.8	172.3	1,738.1	917.647	1.894
1992	472.0	256.7	101.7	162.9	162.9	12.7	32.9	314.3	1,516.1	179.6	1,695.7	918.267	1.847
1993	450.6	254.4	100.5	160.1	159.8	12.5	32.4	314.0	1,484.3	188.2	1,672.5	918.596	1.821
1994	430.0	252.6	98.9	157.4	156.8	12.2	31.8	306.5	1,446.2	196.9	1,643.1	918.887	1.788
1995	411.0	251.4	97.9	155.0	154.1	12.0	31.3	307.6	1,420.3	205.8	1,626.1	919.034	1.769
1996	398.1	250.6	96.9	153.0	151.6	11.8	30.9	304.0	1,396.9	215.2	1,612.1	919.581	1.753
1997	386.9	249.9	96.2	150.8	149.1	11.6	30.5	303.3	1,378.3	224.7	1,603.0	920.019	1.742
1998	378.2	249.7	95.6	149.0	146.8	11.3	30.1	303.6	1,364.3	233.7	1,589.9	920.567	1.736
1999	373.1	250.1	95.0	147.5	145.0	11.3	29.8	305.3	1,357.1	246.0	1,603.1	920.530	1.741
2000	367.3	243.6	94.6	141.1	138.1	10.6	28.3	307.9	1,331.5	258.4	1,589.9	920.493	1.727
2001	356.1	252.0	94.5	144.9	141.6	10.9	29.3	309.7	1,339.0	274.0	1,613.0	919.727	1.754
2002	336.9	249.4	91.2	140.7	137.2	10.5	28.5	305.9	1,300.3	288.5	1,588.8	919.362	1.782

ALCAN PROJECT NEGOTIATED VERSION—DIRECT CONSTRUCTION COSTS/CAPITAL COSTS

[5 percent escalated dollars in millions]

	1978	1979	1980	1981	1982	1983	1984	1985 and after	Total direct construction costs	AFUDC	Total capital costs
Alcan Pipeline Co.			$922.4	$1,141.8	$680.6				$2,744.8	$590.0	$3,334.8
Foothills—Yukon:											
(a) North of Whitehorse	$8.1	$70.2	179.6	221.1	30.2				509.2	143.0	652.2
(b) South of Whitehorse	9.1	78.4	214.8	267.6	50.0	$74.6	$12.5		707.0	183.2	890.2
(c) Dawson/Whitehorse link				18.4	126.0	200.0	72.5		416.9	92.4	509.3
Westcoast—North:											
(a) North of N-2		39.5	86.6	214.1	280.0		114.0		734.2	111.5	845.7
(b) South of N-2		31.2	68.5	163.0	80.9		22.2		365.8	74.8	440.6
AGT (Canada):											
(a) 48 in				451.0	230.0		68.7		749.7	102.3	852.0
(b) 42 in	.4			79.8	113.8	61.1	15.3		270.4	34.3	304.7
(c) 36 in	.2			59.4	42.5				102.1	13.8	115.9
Foothills—Saskatchewan											
Westcoast—Southern				50.9	13.9				64.8	10.7	75.5
Subtotal to Lower 48	17.8	219.3	1,471.9	2,667.1	1,647.9	335.7	305.2		6,664.9	1,356.0	8,020.9
Northern border			37.9	448.9	808.2				1,295.0	131.6	1,426.6
PGT			74.5	171.0	69.7				315.2	52.1	367.3
P.G. & E.				52.2	284.3			$173.2	509.7	36.6	546.3
Total project	17.8	219.3	1,584.3	3,339.2	2,810.1	335.7	305.2	173.2	8,784.8	1,576.3	10,361.1
Memo: Delta-Dawson lateral		9.0	4.5	63.8	209.3	391.2	186.8		864.6	155.6	1,020.2

Senator HATFIELD. Would you explain again very slowly for me how you are projecting the method of handling your debt guarantee when you are computing 1975 dollars in value of, say, 1983 and 1984 and so forth?

Mr. MILLARD. Senator Hatfield, you said debt guarantee. That implies an obligation by a third party. We do not plan on obligations of third parties to support this project. We believe this project under certain conditions of which we think there are present in this case, can stand on its own feet.

In other words, we believe we can face the long-term debt and the bank debt which the financing of this project will assume without outside guarantees, just based on the arrangements which these transportation companies will make with the producers who will deliver the gas to them and the pipeline transportation and distribution companies.

Senator HATFIELD. When you talk about the third parties obligation, could I carry that then to the western leg? Is the western leg predicated on any dedication of the States' royalties or any such third party role?

Mr. MILLARD. No, sir, I think of all of the segments of this financing, the financing of the western leg may be the easiest. The two companies which will dominate the western leg, the two great gas companies of California, have enough credit to stand behind everything which is needed for the financing of the western leg.

Senator HATFIELD. And any impact on the price structure on that leg as differentiating from, say, price structuring for the deliveries.

Mr. MILLARD. Senator Hatfield, I must admit I do not know enough of the details about California gas economics to be specific in answering your question. Every new supply of gas at a price different from the average cost of the gas in the present supply must have some effect on prices. But I am not aware of anything which makes the western leg in this respect different from the rest of the system.

Senator HATFIELD. Speaking of supply, supply alone, of course, is not the factor you must consider, you must consider delivery as well.

Mr. MILLARD. Yes; these companies are regulated by a very vigorous public service commission.

Senator MCCLURE. Do you have contracts with the producers for the delivery of gas?

Mr. MILLARD. No.

Senator MCCLURE. Do you have projected delivery costs to the customer?

Mr. MILLARD. Senator McClure, we have projected in great detail the cost of transportation, which is the part for which we are responsible.

Senator MCCLURE. I understand that.

Mr. MILLARD. But we have not been called upon to do anything, even express opinions, about the wellhead price. I do not have to remind anybody of the great debate which is going on in this matter and, of course, the only thing which we can do in thinking about the delivered price of the gas is to make wide assumptions within the scale of the differing opinions on the subject.

Senator MCCLURE. Your assumption must be either it is regulated and therefore not a matter of concern to the transmission company, or that the market will pay whatever the price is regardless of whether or not it is regulated.

Mr. MILLARD. This is exactly correct.

Senator MCCLURE. That causes a number of people some concern and I think would cause you some concern as to whether or not this is a viable project, if as a matter of fact the delivered price of the gas to the ultimate consumer gets too high then your project is no longer feasible. If as a matter of fact it is lower, then it becomes more feasible and with no external guarantees, I would think that would have a great bearing upon the financeability of the project.

Mr. MILLARD. There is no question your statement is correct, sir. However, if it addresses itself to the general probability that reason in one definition or another will prevail, I would like to say the amount of gas on which these three companies sit is much too momentous in terms of the overall amount of gas to be supplied to assume that no solution will be found.

Senator MCCLURE. I recognize that. There are two elements of risk that have been injected here. One is the price to the ultimate consumer and the other is the lack of guarantee. Whenever the element of risk enters, the cost of financing goes up. With those two elements of risk present, it seems to me we can anticipate the higher of the possible ranges of cost and therefore a larger bill to the consumer.

Mr. MILLARD. Maybe you will permit me to answer this question in concrete terms. No price of gas suggested by responsible people for the Prudhoe Bay natural resource resulted in a delivered price which is higher than the prices which will have to be paid for the import of LNG from such far away places as Indonesia and Malaysia which is now actively being prepared. I don't believe—and this is my individual opinion—that natural gas from Indonesia and Malaysia should set the level of domestic gas prices, I think any kind of reasonable assumption about the sum total of this project's prices and transportation costs still falls within the framework which is practical for the U.S. economy at this point.

Senator MCCLURE. It is suggested in the statement there will be some substitution of Canadian gas, or at least some substitution is possible. As a matter of fact, one of the justifications is if this arrangement is approved and under way, some of the Canadian gas can be shipped to the United States for future substitution of Alaskan gas. At what price would that Canadian gas be furnished to the U.S. market?

Mr. MCMILLIAN. The current export price now is slightly over $2, $2.12 to $2.16. We would expect those gas volumes, those predelivery gas volumes would be at the current or then-current export price of Canadian gas as experienced in the other contracts.

Senator MCCLURE. Would the future replacement of Canadian gas with Alaskan gas be on a volume basis or a price basis?

Mr. MCMILLIAN. That has yet to be negotiated but I would assume it would be on a volume basis. That is the easiest accounting method to use.

Senator MCCLURE. I would think it might assure the lowest possible price for the current deliveries and that, I assume, has some interest to the members of this committee.

Mr. MCMILLIAN. Yes, sir. To get to your wellhead pricing problem again, which is a problem, and that is the reason gas contracts with producers have not been signed, the FPC has not established a wellhead price, or, if we assume the price mentioned in the House energy bill of $1.45 plus 10 cents escalation, we are looking at $1.55 for the wellhead price of gas.

The question there is: at the wellhead or tailgate plan. We are looking at the processing charge in the field. In reading this report here and in listening to some other governmental people who have talked to us, it should range from zero to 70 percent and the processing charge and the fees to get this in condition to go in our pipeline, and it is a matter of who pays that processing charge, whether it is paid by the producer or the transportation system. You see some actual transportation costs used in economic comparisons in the President's report. Also in the President's report is a year-by-year analysis of the costs.

I believe the Chairman asked that these be presented, and we will.

Depending on who pays the processing charge and what functions producers have in the financial package, you are looking at probably $3.75 or $4 gas at that time.

Senator McClure. The delivered price?

Mr. McMillian. Yes.

Senator McClure. You indicated you expected the Canadian gas would be at what was then the current export market level. Do you have any agreement to that effect?

Mr. McMillian. These prices are established by the National Energy Board in relation to several factors, world price of crude oil, the competing forms of energy in our market. But they establish that price. We are talking about the total price of bringing Alaskan gas down through our systems to our markets, in that time, 1983, you will be looking at approximately $20 a barrel oil. We think it will be very competitive.

Senator McClure. I was looking at that near-term delivery of Canadian gas.

Mr. McMillian. Yes, sir. We have a contract with some of the Canadian companies where we are now in the process of going through the regulatory procedures in Alberta and Ottawa for 200 million cubic feet a day. That is our previous delivery volume we discussed. We anticipate that will be at the $2-plus market export price—that Canada sells her gas to us for.

Senator Hatfield. I have one question. I would like to go back to Mr. Millard. Mr. Millard, it is my understanding your decision contemplates it will be necessary for the producers to extend their line of credit to the banks for the debt guarantees for which Alcan would reimburse them with some sort of fee system for the service. It is further my understanding that the producers so far have been unwilling to make this kind of agreement. Is that correct?

Mr. Millard. Senator Hatfield, not entirely. We have had no conversations with the producers on this matter, but we do not contemplate the producers should guarantee any thing. We, being very much aware of the size and novelty of this project, of course, are also very much aware of the fact that there are very many uncertainties with respect to events that will take place 2, 3, 4 years from now, as the financing goes along.

One of the most important aspects of this unpredictability of all aspects of this financing is the possibility of over-runs in cost. We have not believed the producers should play a basic initial role in this project in relation to its financing, but we believe it will be necessary to provide fallbacks in the event in which the money provided for in the initial financing should not be sufficient to finish the project.

We believe the producers would be logical participants in additional financial efforts to complete. The stake for the producers in this thing, as I said before, is very large. I believe the operating profits of the three companies from the sale of gas which, in fact, are incremental profits, because most of the Prudhoe Bay costs has been expended and debited to the production of oil, would be on the order of a billion dollars a year. So they have a reason and in fairness a real interest to participate in line with what this means to them.

Senator HATFIELD. You are saying it was not contemplated they would be expected to extend their line of credit to this?

Mr. MILLARD. Absolutely not.

Senator HATFIELD. One last question. You talk about cost overruns as being the determinate factor. The Report indicates, I believe, some possibility of 32 percent overrun. Yet Mr. McMillian this morning indicates that in his testimony that, I assume is the Report based on the Alaska experience, that was experienced as high, you indicate the costs were unduly high and you gave a few reasons why you thought you could keep them at a minimum. Now Mr. Millard raises the cost overrun factor.

I feel a little uneasy, frankly, about the Report language and reading your testimony this morning. Do you have any way to allay some of my fears on that?

Mr. MCMILLIAN. I will try, Senator. There is a problem. As you know, Alyeska had one of the greatest cost overruns of any project.

Senator HATFIELD. You haven't dealt with the military very much.

Mr. MCMILLIAN. We are not criticizing Alyeska which had a first time project under hazardous conditions and they did build a system and it is operating, but I think we have learned a lot by the Alyeska experience. There were faults of management, faults of labor, faults of the governmental coordination. But I think we have learned enough from that to make this project work smoothly.

We have been fortunate enough to take the actual Alyeska cost experience and build up from increments of their actual unit production costs. We have derived our estimates from the actual Alyeska experience. There are still a lot of outside factors that can influence major cost overruns. One is a type of inflation that put everything out of kilter and affected all projects. The second, the coordination we will have with our Government, regulatory agencies, we know certain specific standards we have to meet, stipulations with DOI, DOT, we know the Alyeska situation when they had troubles getting this effort organized in any workable manner. We hope the Federal inspector mentioned in this report will help expedite that.

These factors can fall in place if we work together with the Government and with these other parties. I think we can keep within our cost estimates. A lot depends on these factors. The other thing, Senator Hatfield, is we have to look at our Canadian partners who have been constructing in their area, in their backyard, for many, many years. They have had an actual construction experience under similar conditions, in similar territories, and they have been within budget and within their cost estimates for many years. So we feel confident their cost analyses are a good basis.

In some of these factors they took the overrun, the Presidential report applied some of these factors and these numbers. That is what I was addressing my answer to.

Senator METZENBAUM. One question I can't get through my head, where are you with respect to the producers in your negotiations?

Mr. McMILLIAN. We are standing on their door waiting to enter and mention negotiations. The first step has to be the establishment of a wellhead price or a tailgate gas price for the processing plants, but it has to be established by the FPC. Until we know what that would be, for us to sit down and go through these negotiations——

Senator METZENBAUM. Have you discussed the matter at all with the producers?

Mr. McMILLIAN. I think every transmission company I have named involved in the United States has had at least several talks with all of the major companies. They all say they are waiting to see what the wellhead price will be.

Senator METZENBAUM. There is a report a professor of petroleum geology at the University of Southern California has done for the State of Alaska. He concluded the production of natural gas from the Prudhoe fields could bring about a decrease in oil production of up to 4 billion barrels of oil, of up to 44 percent of the Prudhoe reserves. I know nothing at all about his credibility. He is going to testify tomorrow.

You are before Congress asking for approval of the decision that is before the Congress, and my question is—what will you do if the producers turn their backs on the entire subject? As Senator Hatfield has pointed out, there is a clear indication in the decision that the producers are expected to be called upon. He just pointed this out to me. The producers and the State of Alaska are directly major beneficiaries of this project. The decision says they should participate in the financing either directly or in the form of debt guarantees.

I have difficulty in understanding this whole situation. That statement says they are going to be called upon for debt guarantees. Mr. Millard says they are not really being called upon for that exactly. Certainly, you cannot have any pipeline operation without an availability of product, and government is moving but there have been no direct conversations as I understand it between Alcan and the producers. I have difficulty understanding that situation.

Mr. McMILLIAN. There has been a lot of contact with U.S. producers. Let me answer your questions one by one.

First, the professor that is going to testify is going to say there is about a 4 billion barrel loss. I don't know the professor. But I know this. I know we made extensive studies, including one by Core Laboratories, an outstanding engineering firm of the United States; and the State of Alaska used the Van Poollen study which is another outstanding engineering firm in Denver. Our studies were about the same, in that by taking reasonable volumes of gas out of this reservoir and by having a water pressure maintenance program, that we believe, there will be no appreciable loss of oil due to gas production.

This professor could not have had the knowledge of the depth of the study we had and the State of Alaska had. Also we know our reservoir performance studies closely agree with the major oil companies that have spent considerable time and effort in this.

I think whoever this professor may be, whoever he may be, he is wrong if he says so—we will come up here and prove him wrong in that statement.

Senator METZENBAUM. I don't know if he is right or wrong, but it relates to my basic question, and that is why you have not opened the discussions with the oil companies.

Mr. McMILLIAN. We have discussed, we have tried to discuss with them. You look at the finished price of this gas, if you did not have any energy bill—you went on the standard basis today that you have—and at the time of this field of drill you would be looking at 24 cent gas. If you go to the U.S. area pricing today, it would be $1.45, $1.50, in that range. If you took the President's bill, it would be $1.75. So the variations that producers receive from this gas would vary, so the producers are saying, wait a minute, we don't want to make a contract today that might prejudice us by a penny higher price at a later date.

They are waiting for this price to be established by the FPC before they enter into a contract. I think everybody has talked to them. Everybody wants to deal with them. But they are saying we are going to set this price up so we will see what we are going to get. As for them keeping that gas, I don't think they can afford to do it.

In the first place, it is going to cost them around $350 million a year to reinject this gas back in the reservoir. They are going to burn up 4 to 6 percent of the gas volume in energy to do that, to continue that and for them to do this over a period of time would be a considerable economic loss to them. Rather than receiving $1 billion a year for sales like they could, they would be spending $350 million to put it back in the ground.

Senator METZENBAUM. That is what you say as the buyer. What have they said as the prospective seller? Have they said to you they will sell you the gas?

Mr. McMILLIAN. They have indicated they want to sell us the gas. They are willing to work with us in designing the processing plant, but they want to defer the definitions of where they want to stand in the entire picture. When we are talking about producer guarantees, participation in debt, I will let Mr. Millard explain this better, but I think we are not asking them to guarantee something. They can participate in a layer of debt where their debt becomes part of the overall structure, where they repay this debt back. It is not just an obligation where they pay out something and not receive something in kind.

Senator METZENBAUM. Are you assuming the producers will develop the gas processing plant at their own expense?

Mr. McMILLIAN. That depends on the incentive the FPC or Dr. Schlesinger gives them for the price of their gas. Nobody can make them do anything like that. They can only make them wish they had done it.

I think to receive $1.45 wellhead or $1.45 tailgate or whether they go to another pricing mechanism, it could be to the oil companies' advantage to build these gas plants. If I were one of the producers, I think I would try to optimize my dollar recovery from that field.

Senator METZENBAUM. How much additional money would you need in order to build a gas processing plant?

Mr. McMILLIAN. About $2 billion.

Senator METZENBAUM. Two billion more?

Mr. McMILLIAN. Yes.

Senator METZENBAUM. Has that contingency been provided for?

Mr. McMILLIAN. Not in the costs you have before you, the transportation costs. When I mentioned the costs to you of zero to 70 percent on processing costs, that is amortizing, this cost and processing costs, and I also mentioned to you the $1.45, either at the wellhead or the tailgate of the plan, it is according to the FPC's discretion.

Senator McCLURE. If I understand it correctly, the Department of Justice has indicated the producers can have no equity position in the pipeline.

Mr. McMILLIAN. We don't expect them to. But it doesn't say anything about not having any debt into it or layered debt.

Senator McCLURE. They might have indicated they might have a debt guarantee but I don't think they have said anything about layer debt.

Mr. McMILLIAN. I think we are getting messed up on the technical terms. I will let Mr. Millard speak to that.

Mr. MILLARD. I believe the findings of the Department of Justice say while there is no reason why the producing companies could not guarantee debt or own debt securities, the report to Congress clearly excludes as far as Government policy is concerned any ownership of the producing companies in the equity of the transportation companies.

Senator McCLURE. But you don't think it prevents them from owning debt securities?

Mr. MILLARD. It specifically says they would be allowed or it would be in accord with Government policy if they would own debt securities.

Senator McCLURE. Would you, Mr. McMillian, object from your standpoint, to the producers having an equity position or is that simply a reflection of acceptance of Government policy?

Mr. McMILLIAN. I think basically we don't think they should have an equity position. We are in the transportation company business. We are regulated, we have different incentives. I think we are better off without them as active participants in our business. It is two different lines of thinking. Financially we are structured much smaller than the oil companies. We think they ought to do their thing. We don't mind the debt position but we don't think it should be an equity position.

Senator McCLURE. You would like their money but not their control.

Mr. McMILLIAN. That is one way of putting it.

Senator HATFIELD. Could I make an observation? I could not help but thinking as I listened to this, the magnitude of this project, Mr. McMillian, that historically I guess you could say this is the largest private undertaking since Canal Internationale was formed in Paris in the 1870's. But also I am mindful questions were not asked then that should have been asked.

I am hopeful you understand our concern. This comes at a time when some of us are immersing ourselves in the history of the canal experience, which was such a large private endeavor and which had to be broadened to salvage it for defense for ourselves.

I must say I have ambivalent feelings. I have great admiration for your vision and undertaking. I have strong reservations about what one can expect from this kind of undertaking based on the data we have had thus far. I do appreciate, Mr. Chairman, the opportunity to inject these questions at this time to satisfy our curiosity and our obligation to interrogate and understand clearly what the commitments are and what the assessment of success will be. I want to congratulate you for putting together a very remarkable session in a very short time.

I have to ask these questions not to cast doubt but to become better acquainted with the overall picture.

Mr. McMillian. Thank you sir. We appreciate the questions.

Senator Metzenbaum. I think you were going to get into this question of when debt guarantees are not debt guarantees as far as the producers are concerned. I am not sure that has been clarified.

Mr. Millard. Senator Metzenbaum, when the great oil companies will find it convenient to sit down and talk to us about it, we would like to propose to them that they would stand ready to participate in overrun financing in a manor to be determined.

What that means in the most general terms is if, for instance, the basic financing will be arranged in a framework of a $10 billion project and it turns out the project will cost $12 billion, that at that point the oil companies will be ready to purchase additional bonds in part or in whole which will be needed, which would have to be sold in order to provide the higher cost of the line.

It is a riskless proposition. This line will be built under the very close scrutiny of Government agencies. We hope based on many pages of this report, that it will be predetermined which part of the cost is acceptable from the regulatory point of view.

In other words, what we say the oil companies should do is to be coinvestors in the public utility framework, at peace with the regulatory authorities, and therefore, in a riskless fashion.

Senator Metzenbaum. You are saying they ought to be investors. The Department of Justice is saying they should not be investors.

Mr. Millard. If I may clarify that, the Department of Justice does not want them to own stock in the company. The Department of Justice has no objection to their owning bonds.

Senator Metzenbaum. You don't consider that as an investment?

Mr. Millard. No. The Department of Justice and the Department of Energy are clear on that.

Senator Metzenbaum. Mr. Millard, educate me, if you will, please. First of all, there is a question of going into these negotiations as to whether the producers will be willing to enter into agreements at all. I don't gather from the testimony there is any absolute assurance along that line except to indicate they are being led to talk with you——

Mr. Millard. That is entirely correct.

Senator Metzenbaum. Now you go into negotiations and you say we want to buy your gas and we want to pay so much per million cubic feet. That is one set of negotiations that you have to assume somehow relates to world market prices. It has some limits on it because the Federal Energy Regulatory Commission is going to allow a fair rate of return to you, but that does not mean they are going to let you overpay for gas.

Now, along the line you are going to say incidentally, one of the last items in our negotiations, is what will happen in the event the project gets in trouble and has a cost overrun of $3 billion. We would like you to put up the $3 billion. We know that you will have to provide some kind of incentive over and above the normal interest factor.

What kind of incentives would the producers demand, or what do you have in mind for the producers at that point, assuming a gas price at the wellhead has been negotiated, and assuming the companies are not going to accept a flat rate of return for their dollars that they can use them more effectively than that? What is the line of approach that you see at that point? I am certain you have thought about it.

Mr. MILLARD. The producers have invested approximately $8 billion in a system of oil transportation owned by them in order to bring to market oil in which their operating profit can be estimated to be somewhere between $2 and $3 billion. Their operating profit, using the proposals which have been made for the price of Alaska gas, would be on the order of $1 billion.

Senator METZENBAUM. Over and above the $2 to $3 billion?

Mr. MILLARD. Over and above the $2 to $3 billion.

Senator METZENBAUM. What you are saying here is they would then have a return of $3 to $4 billion a year on the $8 billion investment if they sell their gas?

Mr. MILLARD. I did not use the same aggregates, but what I wanted to really say was it would not be an unfavorable proportion of additional return to original investment judging by their own standards if they were asked to supply in bonds—and risklessly—$2 to $3 billions in order to get an additional return of $1 billion a year.

Senator METZENBAUM. To put it another way, they could increase their profits anywhere from 33⅓ percent over their normal return?

Mr. MILLARD. In a riskless fashion, making an investment which will be essentially riskless.

Senator METZENBAUM. Mr. McMillian, the variable rate of return which will be holding down cost overruns, leaves the job of establishing that return up to the new Energy Commission. How high would that rate of return have to be for you to complete the project?

Mr. McMILLIAN. I think this is essentially the point. We want to do everything we can to build this system as economically as we can.

We also have a point, if our rate of return, if one of our partners or supporters, as mentioned yesterday, would have to be sensitive about this rate of return, if our rate of return is too high, then we have a market question. We get lynched in the marketplace. As you mentioned here, several factors, gas has to be marketable, it has to be sellable in the market areas.

We think—there is some discussion now on this variable rate of return, how effective it would be. As far as my company and any of these companies think, incentive could be built in there that would give us ranges that would be very heplful. To give you the exact ranges of what it would be, how high, how low, I think we have not really addressed that question. We will have to sit down at the FPC.

Senator METZENBAUM. I am sure you have made some business projections. What do you anticipate that rate of return to be?

Mr. McMILLIAN. The rate of return is 16 percent in Canada, 15 percent in the United States, with a 10-percent debt charge.

Senator METZENBAUM. Is that after amortization on the debt?

Mr. McMILLIAN. Yes, sir.

Senator METZENBAUM. How much are you figuring on the amortization? What are you figuring as the debt rate, and what are you figuring as the debt service charge?

Mr. McMILLIAN. We figure all of our cost estimates are based on 10 percent debt.

Senator METZENBAUM. What I am asking is, when you say 10 percent debt, you are talking about the 10-percent rate as far as the debt charges are concerned, or are you talking about the 10-percent amortization rate?

Mr. McMILLIAN. Ten percent rate on the 20-year depreciation schedule.

Senator METZENBAUM. What kind of amortization rate would that require?

Mr. McMILLIAN. Twenty years.

Senator METZENBAUM. I guess I am not making my question clear. If you pay a 10-percent interest rate, then you have to pay back the money within 20 years. That then requires an amortization rate of 11½ or 12 or 12½ or 12.2 or something like that, I am not sure.

What I am asking is, what are you figuring it to be? I gather the 15-percent return on equity over and above the debt service charges which would include the 10-percent interest rate plus the amortization of the debt?

Mr. MILLARD. May I answer?

Senator METZENBAUM. I am sorry if I am confusing you.

Mr. MILLARD. Maybe that is in our domain. All of our projections were made, Mr. McMillian said, on the basis of the 10-percent interest, of a 20-year amortization of the debt, or depreciation charge of over 25 years and not with a constant debt service.

In other words, in every year we amortize one-twentieth, generally speaking, and we pay interest on the debt outstanding in that year.

Senator METZENBAUM. So you are saying the rate of return would be 15 percent plus 5 percent which is on the 20-year basis for the retirement of the debt; thus, 10 percent interest charges. At the end of 20 years, you would then, assuming the pipeline was still operable and there was still gas flowing, your return at that point, absent any other considerations, would then be 20 percent per annum, is that correct?

Mr. MILLARD. Senator, we are in a well-established regulatory framework in this thing. We charge the customer based on a rate base which represents the investment and th cost of service. The main elements of the cost of service, about which you are inquiring, are not the amortization rate but the depreciation rate.

The depreciation rate is based on a 25-year life. There is further interest on the amount outstanding in any 1 year. We are facing the phenomenon of a vanishing rate base.

Senator METZENBAUM. Will Alcan accept the risk of an interruption of service on the pipeline or would that risk be borne by the consumer?

Mr. McMILLIAN. Once the line was in operation and once the gas were flowing, if we have a prolonged interruption for some reason, which is highly unusual in our business, a portion of that interruption or that cost would go to the consumer.

Senator METZENBAUM. I did not get that.

Mr. McMILLIAN. I said if we had a prolonged interruption, which is highly unlikely in our business, we don't usually experience that, but if we had that interruption once service has been commenced, then that charge would go to the consumer.

Senator METZENBAUM. The consumers would pay it, is that what you are saying?

Mr. McMILLIAN. Yes, sir.

Senator McCLURE. The President's proposal and report to the Congress made some extensive reference to the possibility of preconstruction of the eastern and western leg and predicated upon that the possibility of earlier delivery of the so-called Canada bubble, the excess total short-term supply. Is it essential there be preconstruction to increase the deliveries of Canadian gas?

Mr. McMILLIAN. No, sir, it is not necessary.

Senator McCLURE. But it would be necessary to ask preconstruction to reach the volume of predelivery contemplated in the President's report?

Mr. McMILLIAN. Yes, sir. We are negotiating with the Canadians for 800 million a day. Under those volumes there would be some preconstruction of the eastern and western legs we would have to do before this gas could be delivered.

Senator McCLURE. I would assume the volumes of delivery under any such arrangement would depend upon the negotiation of contracts of sales of those volumes.

Mr. McMILLIAN. Yes, sir. There are several phases we have to go through to do this. First, the Alberta regulatory agencies, the governmental agencies, and second, the Ottawa decision and the FPC, it is equivalent procedures.

Senator McCLURE. The statements you have filed here today seem to be in concert with the President's recommendations on that point, am I correct?

Mr. McMILLIAN. Yes, sir.

Senator McCLURE. So the statements you make on page 6 about early deliverability and under point four on page 7 with regard to the western leg, the dates of delivery and the construction of the western leg are as contemplated in the President's decision in his transmission to Congress?

Mr. McMILLIAN. Yes, sir. We feel there is a need for a western leg, there is going to be a western leg. We very strongly believe that.

Senator McCLURE. Again, the details of that western leg, volumes and delivery, would depend upon the financing, the contracting, and the regulatory approval to which you have made reference.

Mr. McMILLIAN. And the amount of gas the California companies and ourselves are able to contract with the producers or other parties for delivery to the Western part of the United States.

Senator McCLURE. Let me try something as an idea then and see if you agree with me on it. In regard to the willingness and the likelihood of the financing, the participation in financing by the producers, if I guess correctly and if I understand you correctly, the expected delivered cost of this gas to consumers is likely to be the Btu equivalency of the lowest possible alternative supply. It is probably not going to be less than that?

Mr. McMillian. No, sir. It would be in that range. It could be higher.

Senator McClure. If that is true, the higher the risk of financing and therefore the higher the risk premium in financing, the lower the possibility of the wellhead price to the producer? In other words, just so many dollars available, if it goes into financing because of higher risk there is less available to the producer?

Mr. McMillian. I think that is relatively correct.

Senator McClure. It would seem to me if that is correct the price is really covered by external events rather than internal events. The producer has a powerful incentive to help reduce the risk inherent in the financing.

Mr. McMillian. We feel that way, sir.

Senator McClure. Thank you very much.

Senator Metzenbaum. Mr. Blair, I have some questions for you. The agreement between the United States and Canada that provides a ceiling on the imposition of Yukon taxes states that any advance payment of tax by the pipeline will be treated as a loan to the government to be paid back with interest in future tax revenues but in no event will the loan affect the cost of service to the U.S. consumers.

How will that be worked out in practice?

Mr. Blair. In practice, we, as the operating company, would borrow the money required and advance it to the Government agencies that have been designated as requiring capital to pay for certain additional services that would be required because of the installation of pipeline. We would develop with the Government a formula for the cost of that money, issue payments, and the carrying costs of money being credited to our municipal tax account or its equivalent of municipal taxes to our taxes for the right to use land in subsequent years.

Senator Metzenbaum. There will be a cost of the money used during that period. Won't the American consumers ultimately have to be paying the cost of that money?

Mr. Pierce. No, Senator. The amount that will be advanced will carry the cost of money and when the crediting procedure comes into effect, there will be an interest charged on that.

Senator Metzenbaum. There will be an allowance made by the Yukon government?

Mr. Pierce. For the interest on that money. So, for instance, if the amount were $180 million interest would be accrued on that amount and when it came time to credit it against taxes, it would be the $180 million plus interest amortized over the period of the lifetime of it.

Senator Metzenbaum. Is the cost of construction in Canada, per mile or per foot, substantially lower than that which it is in the United States?

Mr. Blair. Senator, there is a good deal of variation in construction costs across Canada as between regions of Canada as there is between different regions of the United States. Generally, in the western part of the continent, pipeline construction costs are less on a unit basis than they are in the usually more intensively settled eastern parts of the continent.

There is a general experience that pipeline construction costs, installation costs, in Canada are a degree less than in corresponding parts of the United States. Our construction rates are generally somewhat lower although they vary in both countries, of course, from place to place.

In productivity of pipeline construction, our record happens to be high. It is one of the occupations in which Canadians have become well experienced and skilled in. We had tremendous amount of pipeline construction in Canada during the 1950's, in the period from 1949 through about 1961 there was an unusual amount of pipeline installation which gave us the experience in building the largest diameters and some of the longest pipelines in the world.

Some of the trades that have become particularly proficient in building pipelines—productivity is high and over the years our costs of steel pipe have tended to be somewhat lower than those in the United States on a unit basis. As a result sometimes our cost of debt capital are similar or higher.

It is fair to say overall the Canadian experience in pipeline installation is somewhat more economic than that of corresponding areas in the United States.

Senator METZENBAUM. The Alaska Natural Gas Pipeline Act provides the Federal inspector with a statutory basis so he may examine company records and documents in order to carry out his duties. Three of the companies involved in this project, I think there are three, there may be more, Foothills (Yukon) Pipeline, Ltd., Alberta Gas Trunk Line Co., and West Coast Transmission Co., are not subject to the laws of the United States.

There may be others. Would those companies make available to the Federal inspector such documents he deems essential in order to carry out his responsibilities to our Government?

Mr. BLAIR. Senator, I guess the best way to address that would be through the Canadian Federal regulatory authorities. They have prescribed, for this purpose, that all of the pipeline in Canada is to be under the control of the single company, Foothills Pipe Lines (Yukon) Ltd., and it will be under regulatory control of the National Energy Board.

In Canada we are very accustomed to an examination of our accounts and all of that information would be readily available to the Canadian authorities and I suppose all of that would be available to the U.S. authorities. I don't hesitate to say the capability would be there but a Canadian company reporting on its own costs, is something I don't know about for sure.

Senator METZENBAUM. I would say for myself, I cannot speak for any other Member of the Senate, if this decision is to receive approval, I would want assurances in writing from the various Canadian participants that those company records and documents which would have to be available by American companies would also be available to the inspector, regardless of the procedure. I would ask you, Mr. Blair and Mr. McMillian if you would facilitate that procedure—or at least that answer. I gather from your answer there is a willingness to make the information available. It is a question of the mechanics and procedures.

Three years from now that will have been forgotten. That is the reason I think some advice to this committee on that subject would be, at least from this Senator's standpoint, extremely important.

Are there three or more Canadian companies involved?

Mr. BLAIR. There are several Canadian companies involved. However, the entire Canadian project will be under the ownership and control of a single company, Foothills Pipe Lines (Yukon) Ltd. But besides it will be also involved, West Coast Transmission, Alberta Gas Trunk Line, Trans-Canada Pipeline, and others.

Can I emphasize, Senator, please, my caution in the last answer was only directed toward protocol.

Senator METZENBAUM. I fully understand your answer. I do not mean to make an issue of it. On the other hand, since you could not have anticipated my question, I think if I had been in your position I would have answered in the same manner. But having answered it in that manner, I would indicate to you, I would like for Alcan and its representatives and its staff to advise us of the availability of that information in the future and in writing.

There will be a Board that oversees this, composed of the Secretary of Energy, the Secretary of Transportation, the EPA Administrator, and the Council on Environmental Quality chairman and the Chief of the Corps of Engineers. So it will not be a fishing expedition but a very responsible kind of inquiry.

[Subsequent to the hearing the following information was submitted for the record:]

FOOTHILLS PIPE LINES (YUKON) LTD.,
Calgary, Alberta, October 14, 1977.

Senator HENRY M. JACKSON,
Chairman, Energy and Natural Resources Committee, Senate Office Building, Washington, D.C.

DEAR SENATOR JACKSON: During the course of my testimony before the Senate Committee on Energy and Natural Resources on October 11, 1977, Senator Metzenbaum asked whether the Canadian sponsors of the Alcan Project would be willing to make their books, records and other pertinent documents available to the Federal Energy Regulatory Commission or the Federal Inspector which will be appointed by the President.

Let me begin by stating that Foothills and its subsidiaries will be subject to the complete jurisdiction of the Canadian National Energy Board. That Board will be charged with the responsibility of insuring that all tariffs, charges, and conditions of service for the Canadian segments are entirely just, reasonable, and lawful. Any party opposing our proposed tariff arrangements will have the right to appear before the Board and seek appropriate recourse.

As responsible utilities, Foothills and its subsidiaries have no inclination to object to public examination of their books, records, and accounts in connection with the Alcan Project. We do believe that such examination should be directed through the National Energy Board which has jurisdiction over the Canadian segments of the system.

If the FERC or the Federal Inspector desires to obtain particular information concerning Foothills or its subsidiaries, we suggest that such request be addressed first to the National Energy Board. In our view, this is a procedure which is anticipated by Section 9 of the Agreement between the United States and Canada:

> *9. Regulatory authorities: Consultation*
>
> The respective regulatory authorities of the two Governments will consult from time to time on relevant matters arising under this Agreement, particularly on the matters referred to in paragraphs 4, 5 and 6, relating to tariffs for the transportation of gas through the Pipeline.

If the National Energy Board also decides that it is appropriate for our companies to provide material directly to U.S. authorities on occasion, we would cooperate fully. In making this commitment, our companies recognize the importance of intergovernmental coordination in the construction and operation of an Alaskan gas transportation system.

I trust that this adequately responds to Senator Metzenbaum's inquiry.

Sincerely,

S. R. BLAIR.

Senator METZENBAUM. Mr. McMillian, recently Governor Brown was in Alaska to negotiate the purchase of Alaska's oil and gas, which as I understand it, amounts to one-eighth of the total Prudhoe Bay supply. Supposing the State of California and the State of Alaska were able to come to agreement. How would the Alcan group react if one or both of these States were to take a one-eighth ownership interest in the Alcan pipeline?

Mr. MCMILLIAN. My first reaction would be mad because we did not get some of this royalty gas ourselves.

I think as far as a responsible State having ownership, in the project, I am certain if they had that volume of gas they would have that ownership and system, if they did have that gas contracted for, there would not be anything we could do so therefore we would welcome them to have the ownership. I don't know whether that will happen or not.

Senator METZENBAUM. How do you view the entire question of the Alaska royalty gas and their usage of it. Alaska is indicating they might be willing to sell it on terms where they can take it back if they want to use it at home and the Alaska Natural Gas Transportation Act gives the State that right.

Would such arrangements jeopardize the Alcan project's viability?

Mr. MCMILLIAN. It depends on the contract and the volumes of gas and where they were delivered. Basically I know Alaska wants to optimize the use of its royalty gas to their maximum benefit, which is good. But if a variable of 12½ percent of the gas and ⅛th of the gas was unknown when that gas would be produced or where it would be transported on the initial design of the system, it would add a different degree of complexity, not only due to the design of our system but due to the facts, but for the volume of gas we are talking about. We really feel like the way Alaska could optimize this gas would be in sale and dollar revenue to the State, because they do have excess gas at the tidewater. That would be much cheaper gas to use for industry and other businesses.

It is a matter of how this is structured and when it is brought in. But, yes, if it was withheld or there is some uncertainty about how this gas would go to a market, it would make the financing of the system more difficult.

Senator METZENBAUM. Mr. Blair, how would the Foothills Pipe Lines (Yukon) group react to such a proposal if one of the States of the United States owned one-eighth of the pipeline in Canada? Would the Canadian Government allow such an interest and would the corporate partners be agreeable to such participation?

Mr. BLAIR. We really have not had a reason to address that, Senator. The corporate partners are capable of furnishing the equity required in the Canadian portion of the system and we have not had any reason to suppose equity investment from the United States would be sought.

There is a strong disposition in Canada toward a very high degree of Canadian ownership of gas pipelines. We have featured our ability to divide the equity in Canada. We certainly don't seek investments from a State of the United States, nor do we suppose it would be appropriate or serve any particular basis for them to be included on that basis in Canada.

Senator METZENBAUM. Let me come back to another question. What is the equity value of the Canadian companies involved in this project?

Mr. BLAIR. I can develop that figure, Senator.

Senator METZENBAUM. Roughly.

Mr. BLAIR. Up toward $1 billion in the aggregate.

Senator METZENBAUM. Would you then tell me how the Canadian common stock commitment would be met, which is $855 million, which is obviously an unbelievably high proportion of the total net worth of the companies?

Mr. BLAIR. Senator, Mr. Pierce has worked in this area more than I have, and I would like to pass the microphone to him, please.

Mr. PIERCE. The Canadian equity proponent would be provided, it is expected, over a period of 4 years. It is expected each of the companies who are ongoing property companies now will provide it in the normal course of the financing they carry themselves. Our company last year had something like $160 million in the Canadian public equity market.

A lot of the companies involved, the main companies being West Coast Transmission——

Senator METZENBAUM. What were the earnings of your company?

Mr. PIERCE. Last year? About $40 million, taxpaid.

Senator METZENBAUM. Are you suggesting you can go back to the marketplace each year for 4 years and raise substantial equity capital, particularly for a project of this kind which does not have an earnings backup but only has earnings projections?

Mr. PIERCE. Senator, we won't be matching necessarily equity dollar for equity dollar. We have the ability to go to the debt market as well as the common equity market.

Senator METZENBAUM. For the purchase of common stock?

Mr. PIERCE. Yes.

Senator METZENBAUM. What is the total amount of money raised annually in the Canadian equity and debt market, the investment market?

Mr. PIERCE. Might I just check that? My advisers tell me the corporate debt market, corporate bonds in Canada run about $3 million a year; the equity market fluctuates in Canada.

Senator METZENBAUM. From where to where?

Mr. PIERCE. Some years, I am advised, the equity rates in the public market might be in the neighborhood of $200 million; in other years as much as $500 million.

Senator METZENBAUM. This would require the raising of $1 billion, would it not? More than $1 billion.

Mr. PIERCE. I think it is $880 million.

Senator METZENBAUM. $855 million in the common stock, $445 million in long-term debt, $542 million from Canadian banks. That is without any cost overruns.

Mr. PIERCE. Right, Senator. I think you indicated earlier both the Canadian banks have assets in excess of $100 million, and our money over that period of time would be no problem there. On the corporate debt side, the $3 billion, which is normally raised in corporate debt market, in Canada, that would be no problem.

Insofar as the borrowings of our company are concerned, I would think including a 20-percent overrun, for Westcoast, we would each be looking somewhere in the neighborhood of $400 million. We would anticipate raising that over a 5-year period and would have a combination of the use of the issuance of common stock from our company's preferred stock, from our companies, or ordinary borrowing from the debenture market or the first mortgage market.

Senator METZENBAUM. All of this assumes the economy is going all right, going well. If it does not, and there are times in Canada as well as in the United States and in other parts of the world that you cannot go to the market for money, what contingency, backup plan, do you have?

Mr. PIERCE. We have bank loans in our company to the extent of $400 million which would carry us over a period of time. I might say this: The Canadian capital market has never been quite as bullish as the American capital market, but our company has never had any difficulty raising funds in the public market in the years we have needed to raise the issue.

Senator METZENBAUM. You have never needed to raise this amount of money.

Mr. PIERCE. We have raised as much as this over a 4- or 5-year period.

Senator METZENBAUM. My question is, you have a backup and that is only to go to a bank, is that what you are saying?

Mr. PIERCE. $400 million of contingency with the banks. That is more than the amount of equity we are required to subscribe.

Senator METZENBAUM. I didn't hear you.

Mr. PIERCE. The $400 million contingency fund we have arranged for with the banks is more than the equity we are required to subscribe.

Senator METZENBAUM. The $400 million contingency with the banks you have arranged, is that specifically for this purpose or other purposes?

Mr. PIERCE. For this purpose.

Senator METZENBAUM. How about for the other competing firms, do you know?

Mr. PIERCE. Generally, the other provisions apply; the other main company is Westcoast Transmission, it is basically in the same position.

Senator METZENBAUM. Are you all about the same size?

Mr. PIERCE. Trans-Canada Pipelines would be about the largest company. We and Westcoast would be basically second.

Senator METZENBAUM. You don't anticipate the need to come into the American investment market in order to raise any of the dollars you are talking about?

Mr. PIERCE. Senator, we expect very much to be in the American market with respect to debt. Excuse me, Alberta Gas Trunk Line per se does not intend per se to go to the American market, although it could. The Foothills project itself will be seeking to borrow funds in the U.S. market.

Senator METZENBAUM. That is the projection as submitted to us. That is already contemplated to be American long-term debt. Is that what you are saying?

Mr. PIERCE. That is it, Senator.

Senator METZENBAUM. Mr. Miller, do you have anything you would like to add on this subject?

Mr. MILLER. Senator, I might volunteer if I may, this project will, as Senator McClure pointed out, depend on economics. If it is an economic project that produces economic gas to U.S. consumers. We are at a stage where such elementary matters such as size of the pipe and gage of the pipe are known. We should apologize. I am particularly embarrassed not to be specific about plans. We know from aggregates, from experience, from the strength of all of the entities, that are receiving benefits from this project, provided it is economic, that it can be financed.

Senator METZENBAUM. Mr. Miller, what are the problems, what are the areas of concern that you would advise any investment banking house, any regular banking house, or any common stock investor, concerning his investing his dollars at this point with this project?

Mr. MILLER. I guess I would pick three elements. One is any investor looking at the project would want to be assured it would be completed and produce a transportation system which has gas going in one end and coming out the other end with customers to buy it.

I would tell them to look very strongly at the regulatory and intergovernmental relationships. That we're watching the project as one of the biggest risks, not as one of the biggest protections.

Finally, they would be looking at either the tailgate, the plant tailgate price and the resultant economics of gas to the consumer, and that makes sense on a Btu basis, then the project will work.

Senator METZENBAUM. There are a lot of "if's" at this point. What about the fourth "if," if the producers would be willing to sell?

Mr. MILLER. I think that is part of it. You put yourself in the position of a producer. They are private enterprises that own assets. If they are going to be required to sell the gas at 24 cents or whatever price was used, they won't sell it and there won't be a pipeline.

Senator METZENBAUM. If they are persuaded by this geologist who says as a consequence of the gas being taken from the wells, that there will be a loss of four billion barrels of oil. If they happen to be persuaded there may be some merit to that point, then there would be no gas, the gas would not become available.

Mr. MILLER. They own it. If they were so persuaded, which I find unlikely, they would not sell the gas for transmission.

Senator METZENBAUM. As a business advisor in this matter, I gather you are an investment banking consultant for the Canadian companies?

Mr. MILLER. That is correct, sir.

Senator METZENBAUM. Do you not find it somewhat unusual that there have not been any assurances given at this point from the producers that the gas will be available and subject only to negotiation of price?

Mr. MILLER. Frankly, no, sir, I do not. All I can do is put myself in the position of a producer which is a rather ridiculous position to put myself in, but I will do it. If I had the uncertainties associated with the discussions going on here in Washington about what my assets were going to be permitted to be worth. I would not have a discussion on what I would sell for or whether I would sell.

Senator METZENBAUM. Is First Boston primary investment bankers for any of the producers in Alaska, Exxon, Arco, Phillips——

Mr. MILLER. There are three principal producers. We are not—I will use your word "primary"—we are not primary investment bankers. We have done transactions for Arco. We were one of the managers of the BP stock offering in the United States. We have a certain kind of relation with Exxon. We are not what I think what you would mean by calling us a primary investment banker for any of those three companies. We would be delighted to become so.

Senator METZENBAUM. Which investment banking house negotiated the Sohio–BP transaction?

Mr. MILLER. Which transaction?

Senator METZENBAUM. The merger.

Mr. MILLER. Morgan-Stanley has been associated with Sohio and BP. I don't want to attribute to them the negotiation of it without any better knowledge of it as to who did what.

Mr. MILLARD. I believe it was Morgan Guaranty.

Mr. MILLER. I would not be surprised if that were correct. It was not the First Boston Corporation, I do know that.

Senator METZENBAUM. Loeb Rhoades, do you have a particular banking relationship with Sohio, BP or——

Mr. MILLARD. We have no conflicts of any kind in representing Alcan in its future relationship to the producers.

Senator METZENBAUM. Have you been——

Mr. MILLARD. Only in the most general way, not direct line.

Senator METZENBAUM. How about Amerada-Hess, Texaco, Phillips?

Mr. MILLARD. I used to be, years ago, a director of Amerada-Hess. We have been co-manager of issues for Amerada-Hess but have not had any managerial relationship for the other companies.

Mr. MILLER. Perhaps I should volunteer we are the principal investment banker for Phillips. You asked Mr. Millard about Phillips.

Senator METZENBAUM. Gentlemen, our committee appreciates your being with us this morning. We would appreciate some further advice from the Canadian companies concerning the question I posed to you. You will hear from Betsy Moler of the committee staff. I hope the committee sees fit to ask you to return. If the committee asks you to return you would make yourselves available for that purpose?

Other than that, if you have no futher comments the committee stands adjourned—excuse me, Senator Stevens, I apologize. I regret I must leave for another meeting, would you mind presiding?

Senator STEVENS. Not at all.

We are anxious to develop a record with regard to this project, gentlemen, and I wonder if any of you would comment upon the concept of Canadian content with regard to the line both in Canada and in Alaska? Has that been determined as to what Canada policy will be with regard to materials or contractor activity in Canada or non-Canadians?

Mr. BLAIR. Yes, it has been. The company that builds the pipeline, and which company we control, will endeavor to purchase goods and materials, equipment, and services from domestic suppliers which is a practice that we follow in our form of business from year to year and which has been shown over the years to produce sufficient and completively produced pipeline components.

Senator STEVENS [presiding]. There is a reference, Mr. Blair, in the statement attached to the President's recommendation that commits each government to the principle that supply of goods and services will be on generally competitive terms. Is that to be interpreted as competitive within each country as compared to being openly competitive between, say, contractors for the United States as well as Canada with regard to the Canadian section?

Mr. BLAIR. I am not sure if there is any difference, Senator. I suppose that would be competitive within each country, but I suppose also the result would be the same as if there were complete competition between both countries.

We recognize a real need to do business year after year and to have the competitive firms that will bid against each other and give us reasonable costs and services. I think both countries are interested in keeping that supply line open.

I certainly do not avoid your question. To come to it a more direct way, I would say our expectation is that we can obtain sufficient competitive bids from our Canadian firms and the supply of bids for contracts and services so we can build the line economically and so the total cost will be—will not compare unfavorably with the United States.

Senator STEVENS. I am not being critical. I have a memory of coming into Kenai on a competitive basis and at the time the Kenai field was developed I distinctly recall when the Atko units were the first units bought by the Alaska oil pipeline, Alyeska, and some of the feelings that ensued thereafter.

I know the Canadian people must have similar feelings but I wonder whether the competition of our companies to Canadian firms is going to be available, whether this Canadian content we read in the NEB statement—the NEB statement as I understand it, is 80 percent of the line in Canada must be Canadian content. We are trying to understand whether that means American firms will not be permitted to compete and whether that statement that is in the President's report means its competition within each country as opposed to competition openly.

Mr. BLAIR. I think the assumption has been in Canada the U.S. firms supplying the pipes to the project would supply to the U.S. part of the project and the Canadian firms would supply the equivalent to the Canadian part.

Senator STEVENS. Who is going to supply the money on the Canadian markets, Mr. Blair?

Mr. BLAIR. The capital markets in Canada and the United States.

Senator STEVENS. We have some problem with that, I am sure you know. I have great respect for you and for your firm. We have some problem with the fact that when the Alaska projects were developed, it was Canadian firms that came in and did a considerable portion of the work. Now that the Canadian side is going to open up with the Alaskan firms having experience coming out of the Alaska pipeline stage are not going to be able to compete. I understand that is a national policy. You are not making that, Mr. Blair.

I think some of my friends in Alaska are standing by thinking they are going to have opportunities in Canada, which I do not perceive they are going to have.

Mr. BLAIR. Senator, I know there have been quite a number of cases of protest in Canada that Canadian firms had difficulty from project to project in becoming qualified to bid on work in the United States. I suppose the policies will be as the governments of the two sovereign jurisdictions establish from time to time.

I do think we are entitled to make the one point. The policy of Canadian purchasing need not be associated with any assumption it is going to produce a more expensive project.

I do believe in our productivity, our acquisition costs over the years. We can show there is reason to expect Canadian portion of this line and the U.S. portion can be measured on equal basis.

Senator STEVENS. Knowing your background, I am sure you will do your best to see that is the case. But can you tell me, does the Canadian steel industry have the capacity now to produce all of the steel required for the pipeline on the Canadian side?

Mr. BLAIR. Thank you for your comments, first. We will want to maintain your confidence very much.

Yes, the Canadian pipeline, the pipe-steel industry does have the capacity to furnish all of the pipe required for the project. Also we have tested there is sufficient capacity to continue to supply the ongoing supplies of pipe in Canada for other projects and anticipated in which our own company and Westcoast Transmission and other companies will be involved. We have checked that very carefully to make sure that pipe will be sold.

Senator STEVENS. There has been some indication that Canadian pipe suppliers ought to be expanded at the time when our steel mills are shutting down, our financing of this pipeline through Canada, with the expansion of the Canadian capacity, that does not seem to be the case from what you say. That would not be your opinion?

Mr. BLAIR. The Canadian steel industry is presently undergoing an expansion and the result of the expansion will be to make it fully capable to supply all of the steel for manufacture of the pipeline. Little or no pipe rolling capacity is required of the project.

There may be some increase in pipe rolling capacity for competitive reasons between companies. I know of one company that has indicated advancement in one mill, but that is not required in terms of the aggregate national pipe rolling capacity in Canada.

Senator STEVENS. Part of the agreement is Alaska gas would be provided to the small communities on the Canadian side of the border. I believe there is a specific cost mentioned in the agreement that gas would be replaced as it goes down through your fields and will be sort of a swap as I understand it, handled by your company internally in Canada.

Would you tell me who would pay the capital costs for the installation required, a take-off from the pipe and distribution among small companies

Would it be your company?

Mr. BLAIR. No, Senator. We have undertaken to install with our own company the high pressure lines from the main line to the town gate and to include that cost in the capital and take that into account in the cost of the pipeline. It is a very, very minor cost actually, I think $2½ million is allowed for the eight communities perceived as large enough to be interested in gas supplies. We are talking of a small fraction of 1 percent of the total capital cost of the plant.

Senator STEVENS. I commend you for thinking about those small communities. Will it require just one take-off from a line to serve them or a series of take-offs?

Mr. BLAIR. A series of take-offs which will be at the point of the main line closest to each settlement. This is similar to the way we operate in the Provinces, that has been part of the ethic of cross-country gas pipeline management in Canada, that the people along the way get gas service as well as the people in the large population centers the pipeline eventually goes to.

Senator STEVENS. The cost of the take-off, the local community pays for distribution within their community but not for the capital costs of the take-off?

Mr. BLAIR. That is correct. As this has been laid out from Yukon, those local consumers would pay on a share basis of the high pressure line. It all rolls into the sum total. They are a relatively small component.

Senator STEVENS. Mr. McMillian, will you make the same arrangement with the small communities in Alaska?

Mr. MCMILLIAN. Yes, sir, I am sure we will. We are willing to do that. We will look forward to it.

Senator STEVENS. Will the capital costs pay for the total cost of the project or will we pay for the take-off and the line to the city gates?

Mr. MCMILLIAN. Usually the take-offs are borne by the transportation system, the distribution system is usually a separate corporate structure but the take-off point will be part of it, sir.

Senator STEVENS. I could get a list of all of the small communities involved. They are quite a distance apart as you know. What I want to know is whether the small communities in Alaska are going to have the same treatment as the small communities in Canada? I applaud Canada for what they have done. Mr. Blair has done it, from my knowledge, in his system in Alberta already.

It is something our gas industry has not done. If the community wants to takeoff here, the cost of the takeoff and the line to go to the community and provide its own community-wide distribution system; this is a contrary concept. The pipeline system pays the whole cost of takeoff and the cost of delivering to the city border, community border. Are we going to follow that policy in Alaska?

Mr. MCMILLIAN. I don't think we have approached that problem. I know we have on the takeoff point, the line to that community, I don't think those lines have been brought into overall costs, of analyses or evaluations.

I think all of these different points have yet to be defined.

Senator STEVENS. Then my knowledge of that portion of Canada, some of them are, as we would say, a "fur piece" from that line, yet we are going to build a line over there, and again, I applaud you. But I want to be sure these small communities on our side of the line are going to get the same treatment from this pipeline.

Mr. MCMILLIAN. Senator Stevens, to go back to your question about delivery to these points, traditionally these are taken up on a one by one basis with the FPC and the FPC handles them on an individual basis. But as far as our initial design to permit communities in Alaska, those costs have not been taken into consideration.

Senator STEVENS. I understand. But what I am saying our FPC has not followed that policy, as I understand it, and Anchorage wanted to ask the line be built up from Kenai and the communities in between had to pay their own take-offs.

I would hope we would try to find some way to make certain these small communities, most of them are I think, with one exception, are native communities, quite similar to those on the Canadian side of the line as a matter of fact and I think they should be treated the same way. I would be happy to work with you to see that that is the case.

I hope our new Department of Energy will insist it is the case. They now have some authority to change the policies and practices of the FPC. I hope this is one they approve.

Mr. McMillian, I examined the situation with regard to the Federal law waiver that you have indicated to the President's task force and our Department of Energy that you need. Have you now made any changes or are you seeking any additional waivers of Federal laws pursuant to the Alaska Natural Gas Transportation Act?

I am not trying to embarrass you. I am trying to urge you to ask for them if you need them. Have you examined them to see if you need them? We have set into the record a complete set of waivers. Your former competitor thought it would seek if it had been chosen by the President, and yours was nil as I understand it.

I would like you to urge the President to exercise that authority if it is at all required to get this line built.

Mr. MCMILLIAN. Senator Stevens, we have examined all of the present problems of the law and we think our system can be built under the existing laws. There is one waiver I think asked for in the President's message, but we have no additional waivers to ask.

Senator STEVENS. The agreement contemplates construction will commence on the dates set in Canada and in Alaska. Do we have any assurance of when it will be completed, any deadline for completion of this project?

Mr. MCMILLIAN. Our estimate is it will be completed the first of 1983. Those are our estimates. We believe we can meet that schedule. As far as having any guarantee as to those dates, it would depend on a lot of factors, but we feel there is enough leeway in our construction time schedules, to allow us to meet that deadline.

Senator STEVENS. The Senator from Ohio asked you about the Alaska royalty gas and I had previously asked Mr. Schlesinger to give us an analysis of this proposal that is before us on the basis that only 7/8ths of the gas would actually leave Alaska. I am sure you are familiar then with the proposals before our State which would utilize 100 percent of the royalty gas in Alaska for petrochemical and pharmaceutical concerns. I assume you are familiar with those?

Mr. MCMILLIAN. Not all of those, Senator.

Senator STEVENS. We are taking a lesson from Mr. Blair. There is an added concept involved and being pursued very intensely by the State. Have you yourself examined the contents of this system without that gas. The Alaska gas may not leave Alaska.

Mr. MCMILLIAN. We have not redesigned our system.

Senator STEVENS. I didn't say redesign it. Have you reexamined the economics of it?

Mr. McMILLIAN. Not until we know the exact volumes that will be produced from the field. We are estimating 2.4 billion and, of course, we think we have about 400 million down in Alberta that can be exported. You talk about gas there——

Senator STEVENS. The State of California seems to think it is going to come up and take the gas Anchorage is already using. If I understand their plan, they will take all of the gas from the Cook Inlet and not leave any for Anchorage. Again, we might take a lesson from Mr. Blair on that. I don't think that will happen, and I don't see any excess gas in the Cook Inlet under the circumstances now before us with the California gas utilities. But in terms of this project from the point of view of its financeability and feasibility, I think we would like to know what impact the State's decision to use its royalty gas in Alaska would have? Incidentally, to say, parenthetically, there are still a lot of people who don't understand it is gas produced from State lands and owned by the State under a very unique constitution whereby we have declared oil and gas is owned publicly and is not subject to private ownership. It is entirely a public decision and not a private decision as to what happens to that oil and gas and I am confident what that decision is going to be and I think most people in Alaska are. But I don't know if the companies involved have accepted that fact yet.

Can that be stated? Are we going to keep our oil and gas in Alaska?

Mr. McMILLIAN. I can understand your trying to do this and your State's efforts and goals, but the economic reality of doing some of the things we hope to do, we are going to have to reach to do them. I think for the price of this gas to be processed, to be put into petrochemicals to compete in the world market, would be very difficult with some of your big Middle East plants coming on today where gas is considered zero value.

I frankly—we think a large part of the gas will be sold or else used for some smaller type of businesses, smaller type of iron ore processing, things like that. That would be really beneficial to put in a world type of petrochemical complex.

Senator STEVENS. I am sure you are familiar with the cost of energy there now?

Mr. McMILLIAN. Yes, sir.

Senator STEVENS. The Eskimos are the only people who have gas in the North Country. There is no gas in the North Pole, and I think they are going to react the same way Mr. Blair is speaking to, if that gas goes by. I am suggesting to you the assumption must be the gas is going to be used in Alaska. If the United States changes its position and helps us build new hydroelectric dams, which we only have one of in the State of Alaska, and helps us use some of our other power resources, and helps develop some of those resources, we might think seriously about exporting the gas. But we see no reason to set there and pay the highest price for energy in the country and let our gas go out of the State.

With due respect, as Mr. Blair knows we have had a considerable number of people down in Alberta finding out how they did it, and we do our best to improve on the model.

Let me ask one last question. I have a letter sent to Mr. Coleman by our Commissioner of Revenue, Mr. Gallagher, that goes into the question of this gas-conditioning plant.

This is a subject that bothers Alaska considerably. He was told and I was also told the best estimate for the completion time for the gas-conditioning plant was 4 years and 10 months once the authority to proceed with final design commitments have been awarded, but did not include the time for preliminary studies for the definitive design process nor any questions concerning regulatory hearings.

As a matter of fact, he thinks it is the State's position that the process could easily take 6 years. We have, I am sure you know, considerable economic volume. He says this plant will produce 3.51 tons of sulfur, 100 parts per million of hydrogen sulfide, both of which come under the Clean Air Act and the national ambient standards that it produces 1800 parts per million of benzene, which OSHA controls.

This is the keystone arch of the system, yet we don't see anyone that even looks like they are ready to design a plant. Will this plant be part of the gas pipeline system?

Mr. McMILLIAN. No, sir, it will not. I think the producers during the FPC hearings have always indicated they would be willing to build and operate the plant; I think the time factors mentioned in Mr. Gallagher's letter are unrealistic. I don't think they are right.

Senator STEVENS. They are the same time factors that come from the producing companies.

Mr. McMILLIAN. I don't think they are right. We made a study ourselves. A plant can be built within 3½ years. I think they are going up like strawmen, negotiating for a higher gas price.

Senator STEVENS. I have discussed it with the chairman of this committee to find out who is going to initiate this. It is my understanding the position taken before the FPC was the plant would be started when the gas purchasers would be identified. This is normal gasfield practice. In this situation, I don't see we are going to get the purchasers identified for another year unless I am wrong; they also say they want your project approved by both Governments and the financing completed. Would you tell me what your time frame would be? What would be your feeling as to when you will have approvals from the Canadian Government, both National and Provincial, and have the financing in line?

No one is going to enter into a contract to buy the gas until they see that is the case.

Mr. McMILLIAN. I don't believe that is so, Senator. I believe it would be pretty irresponsible for the companies to do that.

Senator STEVENS. Assuming that is their position, I agree with you; I think someone ought to start right now; I would like to see the State build one.

Mr. McMILLIAN. I think assuming they take that position, that choice would be taken out of their hands, and I don't think they are that foolish.

Senator STEVENS. No one has the right to sell their gas?

Mr. McMILLIAN. If there is a game plan like you are talking about, there might be party that will take them away from it. Congress has a lot of power. What Congress gives, Congress can take away.

Senator STEVENS. That is something Congress can't do, take a company's right to make a contract and make it for them, not if I understand the fifth amendment, not as I understand the contract clause.

Mr. McMillian. You are assuming these companies are irresponsible. They are not. They want to sell this gas. They will negotiate in good faith with us. They are not going to delay us, Senator. We are going to work with them in good faith. To imply otherwise, Senator, I think is unfair.

Senator Stevens. Do you know anything to the contrary? I am told they are going to enter into gas contracts with the ultimate purchasers; you are not, you are going to assume you are going to sell this gas to the ultimate purchasers.

Mr. McMillian. No, sir.

Senator Stevens. It is the producer that is going to sell it.

Mr. McMillian. Yes.

Senator Stevens. How can they determine the risks to sell it unless there is a pipeline and what the pipeline is going to look like and what the costs are going to look like for transportation.

Mr. McMillian. Senator, they tell us the only factor they want to see before they enter into contract, all of these pieces have to fit together. We can run around like the Little Red Hen waiting for the sky to hit us on the head, but I don't think we have to do that. There are things that have worked in this industry for many years. They have always fit together and people have worked together.

Once the gas price has been established by the FPC, and the producers know what they are going to reasonably receive, I think the responsible companies will enter into a contract for this gas. They don't have to wait for a domino effect for each one of the series of things to happen.

There will be certain conditions. If something happens—like in all contracts, you have to judge for that. But I think——

Senator Stevens. I hope you are right. That is not what we are hearing. That is not what we heard at the FPC hearings. And, that is not what we heard at the NEB hearings either. We heard the contracts are going to be entered into when there was a determination of the pipeline and the approvals of the governments had been obtained and the financing had been obtained. If you are telling me there is some way to get these contracts entered into before that, I would be—and Congress can in some way get involved—we will be glad to talk to your lawyers. We would like to help you. Above all, I would like to see that gas conditioning plant started.

I understand everyone has said the same thing, it will be started when the purchasers are identified. Do you know of anything to the contrary on that?

Mr. McMillian. I think the gas contract, if all of the design factors and all of the planning for building this processing plant are not underway, I would be highly surprised. I think it would be very irresponsible of the parties.

Senator Stevens. I am going to suggest to the committee then we get the producing companies in here. I have not been informed and neither has the State——

Mr. McMillian. It might be a good idea.

Senator Stevens [continuing]. That it is underway. I hope there is not a delay factor here that will be disturbing to you, to your company, or to my State as royalty owner.

Mr. McMillian. And to the Nation as a whole. This is too important an energy source for a game plan. I don't think responsible companies would act irresponsibly.

Senator Stevens. It is not just one conditioning plant, by the way. We are informed there is also a need for initial gas separation centers throughout the field. There is one major gas conditioning facility and we are talking about a cost that is $1.8 billion, minimum, in 1975 figures. So we are talking about $2½ billion by the time it gets started. At least somebody has to underwrite that. I have urged the State to step in and do it. That is one thing our State could do and would be very advantageous to everyone concerned.

Mr. McMillian. I am not sure that could be done without initiating an FPC procedure to do it.

Senator Stevens. Do you think it is up to the committee? And I hope the committee will ask the producer-owners and give us a schedule of the producing facilities, and again I would urge you, if you find any of these laws that ought to be waived because of the circumstances involved, I would urge you to take the initiative and bring it to our attention.

I think Congress is more than willing to recommend to the President that he initiate action to expedite action for construction of this pipeline.

I appreciate your courtesy. The committee stands in recess until tomorrow morning.

[Whereupon, at 10:40 a.m., the committee recessed, to reconvene at 8:30 a.m., Wednesday, October 12, 1977.]

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

WEDNESDAY, OCTOBER 12, 1977

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 8:30 a.m., in room 3110. Dirksen Office Building, Hon. James Abourezk presiding.

Present: Senators Abourezk, Jackson, Durkin, Bartlett, Gravel, and Stevens.

Also present: Betsy Moler, counsel; and George Dowd, counsel.

OPENING STATEMENT OF HON. JAMES ABOUREZK, A U.S. SENATOR FROM THE STATE OF SOUTH DAKOTA

Senator ABOUREZK. The committee will come to order.

Senators Gravel and Stevens will join us at the committee table, and will question the witnesses, in the interest of their State.

The first two witnesses will appear as a panel, Stephen Bosworth and Roger Altman. Are they here? I wonder if, for the benefit of the reporter, you would introduce yourselves in order so that she might know who is sitting where.

Mr. BOSWORTH. I am Stephen Bosworth, Deputy Assistant Secretary of State. On my right is Mr. Phillip Trimble, Acting Deputy Legal Adviser of the Department of State.

Mr. ALTMAN. I am Roger Altman, Assistant Secretary for Domestic Finance of the Treasury.

Senator ABOUREZK. I would like to welcome you to the Energy Committee. You are welcome to begin testifying. Please do.

Mr. BOSWORTH. Mr. Chairman, I have a brief statement which I will be happy to make available to the committee for the record.

Senator STEVENS. Could you pull the mike up, please, so that we can hear you?

Mr. BOSWORTH. I have a brief statement which I will be happy to make available for the record. If you agree, I would propose to summarize that statement briefly now.

Senator ABOUREZK. So ordered. Your complete statement will be included in the record at the end of your testimony.

98-069—77——10

STATEMENT OF HON. STEPHEN W. BOSWORTH, DEPUTY ASSISTANT SECRETARY OF STATE FOR INTERNATIONAL RESOURCES AND FOOD POLICY, DEPARTMENT OF STATE, ACCOMPANIED BY PHILLIP TRIMBLE, ACTING DEPUTY LEGAL ADVISOR

Mr. BOSWORTH. I am pleased to be here to appear in support of the President's decision in favor of the Alcan project for the transportation of Alaskan natural gas. In my testimony today I will discuss some of the considerations on which the decision is based including the relationship of the United States-Canada Transit Pipeline Treaty to the Alcan project; and the main points of the agreement between the United States and Canada on principles applicable to a northern natural gas pipeline; as well as the impact of the decision on United States/Canadian relations.

I believe, Mr. Chairman, that Secretary Schlesinger has provided the committee with a full description of the economic factors which led the President to select the Alcan project, and I will not repeat those at this time.

As we have observed in recent years, the energy systems of the United States and Canada are closely related. The United States obtains about 1 trillion cubic feet per year of natural gas from Canada, about 5 percent of our total annual supply. During last year's energy crisis, Canada provided on an emergency basis large, additional supplies of natural gas.

Oil imports from Canada, while substantially reduced from the level reached earlier, remain important to U.S. refineries in the Northern tier States. U.S. coal exports to Canada, exchanges of electricity along the border, and the transit of Canadian hydrocarbon pipelines through the United States are further elements of the important United States-Canada energy relationship.

In the legislation which authorized construction of the trans-Alaska oil pipeline, the Congress authorized and requested the President to enter into negotiations with the Government of Canada to determine the willingness of that government to permit construction of pipelines across Canada for the transportation of natural gas and oil from Alaska to the lower 48 States, and the terms and conditions under which such pipelines could be built.

In response to this mandate from the Congress, and an expression of interest by the Canadians in developing such an agreement, negotiations began in 1974.

At the outset, the Canadians made it clear that they were not prepared to discuss, or approve, a specific pipeline project. The negotiations centered on an agreement to provide general, reciprocal assurances applicable to all existing and future pipelines transiting the United States or Canada.

The United States-Canada Transit Pipeline Treaty, to which the Senate gave its advice and consent on August 3, and which has since been ratified by both countries, provides the following principal assurances: noninterference with the flow of hydrocarbons in transit; nondiscriminatory taxation; and in bond treatment of hydrocarbons in transit.

The Alcan project will benefit from these assurances. Protection against interference and in bond treatment are unambiguous concepts and present no problems of interpretation when applied to the Alcan project.

However, the assurances of nondiscriminatory taxation require that a standard be chosen against which to measure possible discrimination. The treaty provides that "similar pipelines" within the jurisdiction of a taxing public authority will serve as the standard of comparison.

The Canadian portion of the Alcan pipeline will be subject to the taxing authority of four distinct public authorities in Canada: The Yukon Territory, the Province of British Columbia, the Province of Alberta, and the Province of Saskatchewan.

In the three provinces, pipelines exist which provide a standard of comparison under the treaty. For example, Westcoast Transmission, Alberta Gas Trunk Line, and Trans-Canada are pipelines which can be used for comparison.

The treaty provides for binding arbitration should a dispute arise. In addition, the United States would have recourse against the Federal Government of Canada under international law in the event of a violation of the terms of the treaty.

As stated earlier, the treaty's nondiscrimination protection relies upon the existence of a standard of comparison. Since no pipeline similar to the Alcan line now exists in the Yukon Territory, there is not now an appropriate standard of comparison for purposes of tax treatment.

If the Canadians build—as they presently intend—the Dempster Lateral from the Mackenzie Delta to Whitehorse to connect with the Alcan line, this pipeline will be "similar" for purposes of the treaty and will provide a standard of comparison for tax purposes.

However, to guard against the contingency of the Lateral not being built or being long delayed, the Agreement on Principles Applicable to a Northern Natural Gas Pipeline provides for an alternative tax regime applicable to the Alcan line in the Yukon until the Dempster Lateral is constructed.

This regime specifies the maximum levels of taxation which may be imposed in the Yukon during the construction of the line.

Concern has also been expressed, Mr. Chairman, that the cost of settling Native land claims in the areas traversed by the pipeline carrying Alaskan gas might have to be borne by the pipeline and indirectly by the U.S. consumer. This issue was specifically addressed during the negotiation of the agreement.

Paragraphs 11 and 12 of the agreement identify the types of charges which may be imposed on the pipeline by Canadian public authorities. Payment for the settlement of Native claims is not among these, and the Government of Canada has confirmed our understanding that any cost of settlement of Native claims will not be borne by the Alcan project.

In addition, there has been some concern also that selection of a trans-Canadian route might expose the United States to a greater risk of costly delays in construction than the alternative projects. Therefore, in the course of negotiating the Agreement on Principles, we asked for and obtained commitments by the Canadian officials to specific dates for authorization of commencement to construction

The Canadians have done so. The agreement specifies that both Governments will take measures to insure the prompt issuance of all authorizations with a view to allowing main pipelaying in the Yukon to begin on January 1, 1981.

This would, of course, include insuring that the settlement of Native claims does not delay construction. Other construction in Canada will be allowed to begin on a schedule which will enable initial operation of the pipeline on January 1, 1983.

Construction of the pipeline is likely to disrupt the normal development of northern communities along the pipeline right-of-way, as was the case in Alaska during construction of the trans-Alaska oil pipeline.

However, the agreement specifies that indirect socioeconomic costs in the Yukon associated with construction of the pipeline ". . . will not be reflected in the cost of service to U.S. shippers other than through the Yukon property tax."

We understand that the government of the Yukon will borrow money, on commercial terms, from the pipeline companies involved in building the pipeline in the Yukon in order to meet the indirect socioeconomic costs associated with the pipeline construction. The borrowed funds will be repaid from tax revenues.

I have not, Mr. Chairman, mentioned all of the provisions of the agreement. The agreement also covers pipeline routing, cost-sharing, implementing legislation. and consultative procedures.

I would like to say a few words, Mr. Chairman, concerning the impact on United States and Canada relations.

The United States and Canada have a long tradition of cooperation on mutually beneficial projects. Examples include the Distant Early Warning System, the Alaskan Highway, the Saint Lawrence Seaway, the Auto Agreement, and the transportation of Canadian hydrocarbons across the United States.

Our decision to work together on the Alcan pipeline furthers and strengthens this tradition of cooperation. In our view the pipeline agreement exemplifies the type of project where bilateral cooperation is most clearly called for—projects which lead to benefits which could not be obtained by either country were we to address separately the problems concerned.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Bosworth follows:]

STATEMENT OF HON. STEPHEN W. BOSWORTH, DEPUTY ASSISTANT SECRETARY OF STATE FOR INTERNATIONAL RESOURCES AND FOOD POLICY, DEPARTMENT OF STATE

I am pleased to appear before your Committee in support of the President's decision in favor of the Alcan project for the transportation of Alaskan gas through Canada to the lower 48 states. I am accompanied by Phillip Trimble, Acting Deputy Legal Advisor of the Department of State.

In my testimony today in support of the President's decision, I will discuss:

—some of the considerations upon which the decision is based.

—the relationship of the U.S.-Canada Transit Pipeline Treaty to the Alcan project.

—the main points of the Agreement between the U.S. and Canada on Principles Applicable to a Northern Natural Gas Pipeline.

—the impact of the decision on U.S./Canadian relations.

Advantages of the Alcan Project

Secretary Schlesinger has provided the Committee with a full description of the economic factors which led the President to select the Alcan Project. The Project will deliver gas from Alaska to the lower 48 States at an estimated cost of service of $1.04 per thousand cubic feet of gas; 15 cents lower than the estimated cost of service of the alternative systems. Over the life of the pipeline, the lower cost of service on the Alcan system will save US consumers on the order of $6 billion.

As we have observed in recent years, the energy systems of the US and Canada are closely related. The US currently obtains about one trillion cubic feet per annum of natural gas from Canada, which represents about 5 per cent of our total annual supply. During last winter's energy crisis, Canada provided on an emergency basis large, additional supplies of natural gas to US communities hard hit by natural gas shortages. Oil imports from Canada, while substantially reduced from the level reached earlier, remain important to US refineries in the Northern Tier states. US coal exports to Canada exchanges of electricity along the border and the transit of Canadian hydrocarbon pipelines through the US are further elements of the important US-Canada energy relationship. The joint gas transportation project will add a major new dimension to that relationship.

Moreover, by offering a potential transportation system for Canadian gas from northern areas of Canada, the construction of the Alcan Line will provide a strong stimulus to exploration and development activities in that area. Each Government has a strong interest in assuring the maximum availability of energy in our respective countries. This joint gas transportation project thus clearly meet the common interest.

US-Canada Transit Pipeline Treaty

In the legislation which authorized construction of the trans-Alaska oil pipeline, the Congress authorized and requested the President to enter into negotiations with the Government of Canada to determine the willingness of that Government to permit construction of pipelines across Canada for the transportation of natural gas and oil from Alaska to the lower 48 states, and the terms and conditions under which such pipelines could be built. In response to this mandate from the Congress, and an expression of interest by the Canadians in developing such an agreement, negotiations began in 1974.

At the outset, the Canadians made it clear that they were not prepared to discuss, or approve, a specific pipeline project. The negotiations centered on an agreement to provide general, reciprocal assurances applicable to all existing and future pipelines transiting the US or Canada. The US-Canada Transit Pipeline Treaty, to which the Senate gave its advice and consent on August 3, and which has since been ratified by both countries, provides the following principal assurances:

—non-interference with the flow of hydrocarbons in transit;
—non-discriminatory taxation;
—in bond treatment of hydrocarbons in transit.

The Alcan Project will rely upon these assurances. Protection against interference and in bond treatment are unambiguous concepts and present no problems of interpretation when applied to the Alcan Project.

However, the assurances of non-discriminatory taxation require that a standard be chosen against which to measure possible discrimination. The Treaty provides that "similar pipelines" within the jurisdiction of a taxing public authority will serve as the standard of comparison.

The Canadian portion of the Alcan pipeline will be subject to the taxing authority of four distinct public authorities; the Yukon Territory, the Province of British Columbia, the Province of Alberta, and the Province of Saskatachewan. In the three provinces, pipelines exist which provide a standard of comparison under the Treaty. For example, West Coast Transmission, Alberta Gas Trunk Line, and Trans Canada are pipelines which can be used for comparison. The Treaty provides that the governments of these Provinces may levy only those taxes upon the Alcan Pipeline which are also levied upon the similar pipeline within their jurisdiction. Furthermore, all three Provinces have assured the Federal Government of Canada that they will observe the principles of non-interference and non-discriminatory tax treatment contained in the Transit Pipeline Treaty. These assurances are annexed to the Alcan Agreement on Principles recently concluded with Canada and are included among the documents the President has provided to the Congress in support of his decision.

The Treaty provides for binding arbitration should a dispute arise. In addition, the US would have recourse against the Federal Government of Canada under international law in the event of a violation of the terms of the Treaty.

Apart from the legal remedies available under the terms of the Treaty and international law, there is also a strong tradition of cooperation which exists between the US and Canada. In previous joint projects, such as the Saint Lawrence Seaway and the Alaskan Highway, the Government of Canada has met its commitments and honored the terms of its agreements. For our part, we have not interferred with, nor discriminated against the important pipelines which carry Canadian gas and oil across U.S. territory. We believe that this tradition of cooperation, recognition of shared interests, and respect for lawful agreements will continue in the case of the Alcan Pipeline.

Yukon taxation

As stated earlier, the Treaty's non-discrimination protection relies upon the existence of a standard of comparison. Since no pipeline similar to the Alcan line now exists in the Yukon Territory, there is not now an appropriate standard of comparison for purposes of tax treatment. If the Canadians build—as they presently intend—the Dempster Lateral from the Mackenzie Delta to Whitehorse to connect with the Alcan line, this pipeline will be "similar for purposes of the Treaty and will provide a standard of comparison for tax purposes. However, to guard against the contingency of the Lateral not being built or being long-delayed, the Agrement on Principles Applicable to a Northern Natural Gas Pipeline provides for an alternative tax regime applicable to the Alcan line in the Yukon until the Dempster Lateral is constructed. This regime specifies the maximum levels of taxation which may be imposed in the Yukon during the construction of the Line. The regime also establishes a $30 million ceiling on taxation of the Line after completion. This amount is subject to adjustment annually from 1983 to reflect the rate of inflation in Canada, or to correspond to increases in Alaskan taxes on the portion of the Line in Alaska. After the first five years of expected operation of the line, the tax ceiling may also be adjusted to correspond proportionately to increases in the levels of Yukon taxes or grants from sources other than taxes on the pipeline. This alternative tax regime would of course be superseded if the Dempster Line is built because the Alcan line would then enjoy the assurances on taxation provided by the Transit Pipeline Treaty.

Native claims

Concern has been expressed that the cost of settling native land claims in the areas traversed by the pipeline carrying Alaskan gas might have to be borne by the Pipeline and indirectly by the US consumer. This issue was specifically addressed during the negotiation of the Agreement. Paragraphs 11 and 12 of the Agreement identify the types of charges which may be imposed on the Pipeline by Canadian public authorities. Payment for the settlement of native claims is not among these, and the Government of Canada has confirmed our understanding that any cost of settlement of native claims will not be borne by the Alcan Project. Canadian Deputy Prime Minister Allan J. MacEachen, speaking at the signing ceremony held in Ottawa on September 20, said; "(native claims) exist independently from the Pipeline and will not give rise to any charges on the pipeline project. Their settlement is a purely Canadian responsibility."

Construction timetable

There has been some concern also that selection of a trans-Canadian route might expose the US to a greater risk of costly delays in construction than the alternative projects. Therefore, in the course of negotiating the Agreement on Principles, we asked the Canadian officials to commit to specific dates for authorization of commencement to construction. The Canadians have done so. The Agreement specifies that both Governments will take measures to ensure the prompt issuance of all authorizations with a view to allowing main pipe-laying in the Yukon to begin on January 1, 1981. This would, of course, include ensuring that the settlement of native claims does not delay construction. Other construction in Canada will be allowed to begin on a schedule which will enable initial operation of the Pipeline on January 1, 1983.

The cost-sharing formula for the Dempster Lateral contained in the Agreement also provides strong incentives for the Canadians to minimize the cost of building the Canadian section of the Alcan main pipeline. Inasmuch as construction delays are inhereutly costly, the incentive formula gives the Government of Canada good reasons to prevent construction delays.

Indirect socio-economic costs

Construction of the Pipeline is likely to disrupt the normal development of northern communities along the pipeline right-of-way, as was the case in Alaska during construction of the Trans-Alaska oil pipeline.

However, the Agreement makes clear that indirect socioeconomic costs in the Yukon associated with construction of the pipeline ". . . will not be reflected in the cost of service to United States shippers other than through the Yukon property tax." We understand that the Government of the Yukon will borrow money, on commercial terms, from the pipeline companies involved in building the Pipeline in the Yukon in order to meet the indirect socio-economic costs associated with the Pipeline construction. The borrowed funds will be repaid from tax revenues. Therefore, the loan of money to the Yukon Territory by the pipeline companies will have no impact on the cost of delivering Alaskan gas to US consumers other than through the agreed levels of taxation.

I have not mentioned all of the provisions of the Agreement. The Agreement also covers pipeline routing, cost-sharing, implementing legislation, and consultative procedures. I will be happy to discuss those areas further if the members of the Committee have questions.

Impact of the Alcan project on United States-Canadian relations

The United States and Canada have a long tradition of cooperation on mutually beneficial projects. Examples include the Distant Early Warning System, the Alaskan Highway, the Saint Lawrence Seaway, the Auto Agreement, and the transportation of Canadian hydrocarbons across the United States. Our decision to work together on the Alcan Pipeline furthers and strengthens this tradition of cooperation. In our view the pipeline Agreement exemplifies the type of project where bilateral cooperation is most clearly called for—projects which lead to benefits which could not be obtained by either country were we to address separately the problems concerned.

The pipeline will be one of the largest construction projects even undertaken in North America. Its successful completion will engage the skills and productive capacity of both countries and will provide important economic benefits to both countries. It will enable the two countries to provide substantially more gas to consumers at a lower cost than if either of us were to act independently. At the same time, agreement on the Alcan pipeline enlarges the opportunities for further cooperation with Canada in the energy field, and strengthens possibilities for continued expansion of mutually beneficial collaboration between the two countries on a broader range of issues of common concern.

Senator Abourezk. Any other statements from members of the panel before we have questions?

Mr. Altman. Thank you, Mr. Chairman. I also have a prepared statement, much of which I will offer to submit for the record, and I will try to briefly summarize.

Senator Abourezk. Your prepared statement will be included in the record following your testimony, Mr. Altman. We would like you to summarize.

STATEMENT OF HON. ROGER ALTMAN, ASSISTANT SECRETARY FOR DOMESTIC FINANCE, DEPARTMENT OF THE TREASURY

Mr. Altman. As I think you know, the Treasury Department has participated in the Alaskan gas decision process from its initial stages. Among other activities, the Department led an interagency task force, which on July 1, 1977, delivered a public report to the President on financing a transportation system.

As, of course, you know and Mr. Bosworth has reiterated, the President has designated the Alcan system to transport Alaskan gas across Canada. His report discussing the reasons for that decision was forwarded to Congress, and it includes a detailed discussion of the financing issues. Let me again by summarizing the discussion of financing contained in that report.

It observes that the "Alcan project will be one of the largest—if not the largest—privately financed international business ventures of all time."

Obviously, the amount of financing required for such an undertaking is enormous, and raising it is a complex task. Indeed, certain financing issues still remain unresolved.

My central conclusion, however, is that the Alcan project can be privately financed, assuming equitable participation of those parties who will benefit directly from its construction.

The Treasury Department has consistently argued that an Alaska natural gas transportation system could be privately financed given a proper Federal regulatory climate. The President's decision, with the accompanying terms and conditions, would eliminate much of the potential uncertainty of Federal regulation and insure that such regulation will be conducive to both an efficient project and a private financing.

To be specific, the President has recommended a modified form of incremental pricing for Alaskan gas to assure marketability to consumers. He has recommended the creation of an Alaska Natural Gas Office directed by an appointed Federal inspector to coordinate the government's involvement in construction of the project and to insure the project proceeds efficiently.

He has prepared an agreement with the Government of Canada which largely eliminates binational regulatory problems. The President has recommended establishing a rate of return on equity which discourages cost overruns.

He has discouraged the use of new and controversial tariff arrangements which would be subject to time-consuming litigation with uncertain results. Finally, the President has recommended that the field price to the producers of Alaskan gas be established in accordance with his national energy plan, thus eliminating a lengthy price proceeding before the Federal Energy Regulatory Commission and subsequent litigation.

By adopting these recommendations, the Carter administration expects to resolve much of the uncertainty which earlier characterized the Federal regulatory environment for this project. This should eliminate what had been perceived to be a major risk of the project.

In effect, the President's recommendations go far to encourage an economically viable Alaskan gas project, which is the key to a private financing.

One of the issues mentioned above, the form of the tariff paid by gas consumers, is particularly central to financing the project privately. The project applicants originally requested a novel form of tariff referred to as the "all events, full cost of service" tariff, which would have reimbursed the project company for its costs, including the return on and of equity, under any and all possible circumstances, including noncompletion. It was argued by the proponents of that tariff that such a tariff was necessary to induce sufficient private lending for this project.

Alcan's financial advisers have recently concluded that such a tariff will not be necessary. Alcan is prepared, instead, to finance its project with a more conventional tariff commencing only after the project has been completed.

Such a tariff would assure that the project's debt would be serviced upon completion and should satisfy lenders that principal and interest payments on the project's debt will be met.

Essentially, our anticipation of an economically viable project, coupled with this assurance of debt service, leads me to believe that the Alcan project can be financed in the private sector.

Let me emphasize, Mr. Chairman, there are a series of financial questions that are not finalized. The project should be viewed, then, as tentative because these issues include the final determination of the field price, the completion of sales contracts for gas, and the final determination of the rate of return that will be allowed on the equity of the project.

A small group of the largest U.S. insurance companies will provide the bulk of the U.S. debt capital required. Accordingly, their perceptions of the risks involved in financing this project will be critical.

At this initial stage, we cannot be sure how these key lenders will assess the risks or even which risks they will perceive as dominate; for example, the risks of marketability and noncompletion. It will take more than a year before we will know with certainty whether the financing can be arranged.

One important aspect of our conclusion on the private financing is that the parties who benefit from the project can and should participate in its financing. The major and direct beneficiaries of this project are natural gas transmission corporations, the producers of North Slope natural gas, and the State of Alaska.

Their participation will increase the overall private financeability by reducing the amounts which must be raised on the strength of the project's credit alone. I will discuss each of these parts briefly.

As you know, natural gas transmission and distribution corporations comprise the Alcan consortium, and they must provide the necessary equity for the project as well as the equity portion of any cost overrun financing. The strength of this sponsoring consortium, therefore, is a key element of the financing.

Our analysis shows that the firms currently involved in the Alcan project have the capacity to provide these required equity investments. Furthermore, we expect that the consortum will continue to expand and eventually will include a large portion of the entire natural gas transportation industry.

In addition, the Alcan project has the advantage of the substantial equity investment of Canadian transmission corporations, which will total at least $800 million.

The owners and producers of Alaskan natural gas are major U.S. energy companies. This group is primarily composed of Exxon, Atlantic Richfield, and the Standard Oil Co. of Ohio. These companies will benefit substantially from the sale of their natural gas reserves, and obviously require a transportation system to sell them.

These three companies had total assets of $51 billion in 1976 and net income in excess of $3 billion. They clearly have the capacity to participate in the financing of a transportation system, especially as full returns from their North Slope oil and related pipeline investments are realized.

These companies have demonstrated varying degrees of interest and have not yet agreed to participate in the project. It seems in their interest, however, and they should be encouraged to do so.

We think that financial participation by the producing companies can be structured so as to avoid anticompetitive practices, a continuing concern of the Department of Justice. This issue is specifically addressed in the report which has been forwarded to you with President Carter's decision.

Lastly, Mr. Chairman, the State of Alaska will realize substantial revenue in the form of royalty payments and taxes from the sale of North Slope gas. The State will also benefit from use of the pipeline for natural gas distribution and resulting commercial development within the State itself.

The State of Alaska can use a portion of its revenues from the sale of Alaskan oil to assist in the financing of this project. Originally, the State offered to assist in the financing of the El Paso project by guaranteeing $900 million of project debt. Similar State-of-Alaska support for the Alcan project is considered advantageous and is encouraged.

Let me conclude, Mr. Chairman, by discussing the issue of possible Federal financing asistance. We have intensely evaluated this question, because earlier in the process a number of parties claimed that direct Federal financing assistance was necessary in the form of loan guarantees or direct loans. It was argued at that time that this was necessary because of the uncertain regulatory environment which then existed and that only on the basis of such Federal assistance would lenders be assured of repayment in the event that the project was not economically viable.

In particular, Mr. Chairman, the arctic gas consortium, which has withdrawn, claimed that financing assistance by both the Canadian and U.S. Governments was required for financing their project.

In addition, the El Paso proposal incorporated approximately $1.5 billion in loan guarantees under the existing Maritime Administration shipbuilding program. On the other hand, no Federal financial assistance has been requested for the Alcan project.

Alcan's investment banking advisers do not believe that Federal financing assistance is necessary for the Alcan project. The administration shares this conclusion.

In addition, the administration believes that Federal assistance to this project would be undesirable for several reasons which we regard as very important.

One. Federal financial support substitutes the Government for private lenders in the critical risk assesment function normally performed by the private lenders.

Two. Financial assistance also reduces incentive for efficient management of the project.

Three. Serious questions of equity would result from the transfer of project risks to taxpayers, many of whom are not gas consumers or will not receive additional gas supplies as a result of the Alaskan project.

Four. A subsidy in the form of lower interest rates yields an artificially low price for the gas.

Five. Other large energy projects might not be undertaken without similar Federal assistance.

The Government of Canada also opposes Canadian governmental financial assistance to a binational project.

Mr. Chairman, I will simply conclude by reiterating our central conclusion which is that this project can be financed, that the Treasury Department's assessment of the capacity of the gas companies to supply the equity, and of the basic economics of the project to support the project debt leads to that conclusion of private financeability.

Let me emphasize that this is an unprecedented project in terms of the size and complexity, the related financing task is unprecedented. No one can be certain that this will proceed in a conventional private basis, but all of the regulatory decisions proposed by the President are aimed—primarily aimed at an efficient project.

We are confident of the ultimate financing on a conventional private basis. Thank you, sir.

Senator ABOUREZK. Thank you. Are there any other statements before we get to questioning?

All right. Senator Stevens would like to ask some questions.

Senator STEVENS. Mr. Bosworth, you indicate that the timetable is such—I want to make sure that I get your correct statement—that you asked the Canadian officials to commit the specific dates for authorization and commencement, and the Canadians have done so. I am reading from page 48 of the decision report to Congress.

It indicates that, paraphrasing, both Governments will take measures to assure the prompt issuance of all permits required for expedition of construction and commencement with a view to commencing construction according to the following timetable.

Do you feel that is a binding, specific date for the commencement of construction?

Mr. BOSWORTH. We feel it is a binding, specific commitment by the Canadian Government, Senator, that they will have taken all of the administrative requirements necessary to insure that the private companies can commence construction.

Senator STEVENS. Could you tell me just where they bound themselves to do anything by any specific time? We have got just one pipeline. Let's understand this. I want to do everything I can to get it built, but I don't see that the State Department ought to be coming up here telling us that the Canadians have agreed to specific dates for authorization in commencement of construction when they haven't done it.

Mr. BOSWORTH. Well, Senator, in section 7 of the agreement between the United States and Canada on principles in paragraph 2, expeditious construction and timetable, subparagraph A, it says that both Governments will take measurements to assure the prompt issuance of all necessary permits, licenses, certificates, right-of-way, leases, and other authorizations with a view of commencing, et cetera.

We would consider that to be a firm commitment by the Canadian Government that they will, in fact, do that, so that the private companies who are doing the actual construction will be able to have the proper framework of authorization available so that they can commence construction on those specific dates.

Senator STEVENS. Well, I assume that someone has taken into account—I will ask Mr. Altman this later—the fact that no borrower is going to loan money to start working in Alaska until they have completion of the permit and all of the approvals necessary to complete work in Canada. Don't you agree with that?

Mr. BOSWORTH. I would think that any lender to the pipeline companies for construction is going to want to have assurance that, in fact, all sections of the pipeline will be built on schedule. Yes, sir.

Senator STEVENS. I would assume they would have—they would want to have the permits from Canada that would allow the construction from Canada, at least, before they started this pipeline. I mean we have control over our side of the border, but we don't have any control over their side of the border.

My question is, why does the timetable that is set forth in section 2A put the agreements from Canada after those from Alaska? I mean, theoretically, the pipeline company will have all its permits to start on January 1, 1980, to Alaska, but it will not have its permits to start in the Yukon until January 1, 1981.

If you interpret that agreement the way I do, what kind of an agreement is it with a foreign country that says that we are going to have—that is an expeditious timetable.

Mr. BOSWORTH. I think, Senator, that the purpose and objective of this was to assure that all sections of the pipeline would be built and available for service by January 1, 1983.

Now, the specific chronology of the timetable is a question, perhaps, which would be better answered by the companies concerned.

Senator STEVENS. It may be early, and maybe I am not articulating my question.

My question is in terms of dealing with mechanics, why didn't you get an assurance that all permits and approvals that have to be issued by Canada for this line to go through Canada would be issued by a certain date?

Mr. BOSWORTH. I believe that we have that, Senator.

Senator STEVENS. You don't either. It says, "with a view toward commencing construction." There is no agreement here that by a specific date Canada is going to give approval to everything that is necessary to go through their country.

If there is, I would like you to point it out to me.

Mr. TRIMBLE. Senator, I think the dates refer to the respective dates that construction would commence.

Senator STEVENS. I understand that. But where is the date by which they are going to issue all approvals that are necessary to deal with Canada?

Mr. TRIMBLE. We have not gotten a specific date by which Canada would have to issue all of its permits, but we do have a firm and binding commitment that they will issue all the necessary permits.

Senator STEVENS. So, in effect, we have the same St. Lawrence Seaway Agreement again. I am sure you are familiar with the St. Lawrence Seaway Agreement. And I know Mr. Bosworth's statement about the correct cooperation from our Canadian, southern neighbors on that project.

It was signed in 1932. I am sure you are familiar with that. And construction was started in 1954. Now, do you hold that up to the world as an international agreement of great cooperation?

Mr. BOSWORTH. Senator, there was a long delay between the signing of the agreement and the commencement of construction.

Senator STEVENS. Are you familiar with how that happened?

Mr. BOSWORTH. I think there was room for honest men to disagree as to why; the Canadians, I think, would maintain that there was a certain delay on the U.S. side.

Senator STEVENS. What about the Columbia River Treaty? I notice that you left that one out. We neglected in a negotiation with Canada to tie that down.

Did you tie down this negotiation, the approval of the Provincial Government of British Columbia, the use of the public lands that are owned by British Columbia?

Mr. BOSWORTH. Yes.

Senator STEVENS. Where in the agreement is that tied down?

Mr. TRIMBLE. I assume you are referring to the issuance of rights-of-way for the pipeline?

Senator STEVENS. I am. They own the public lands through which this pipeline is going to go. That is why they held up the Columbia River Treaty until we agreed 3 years later to build the Peace River Dam at our expense.

Now, where in this agreement do you have anything wherein the British Columbia Government says they will allow the right-of-way at a reasonable charge and they will grant that right-of-way by any specific date?

Mr. TRIMBLE. The British Columbia Government is not a party to the agreement. The Canadian Federal Government is, and they are responsible for the applications undertaken in the agreement.

Senator STEVENS. They were responsible in the Columbia River Treaty. I was here then. I was part of the Government at the time. They were responsible. They assumed the solemn responsibility that that project would go ahead, and for 3 years the British Columbia Government held it up.

If I am right, you are relying on the letter that is on page 81, the British Columbia Government's statement which says specific details as undertaken will be subject—the subject of the Federal provision agreement to be negotiated at an earliest date as possible. Such agreement should guarantee the British Columbia position expressed in the telegram of August 31 as protected.

Do you have that telegram of August 31?

Mr. BOSWORTH. No, Senator. We do not. The Canadian Government has taken the position that that telegram of August 31 deals with matters which are solely the responsibility of the two Governments concerned and are not relevant to the implementation of this agreement.

Senator STEVENS. So we don't have an agreement with British Columbia?

Mr. TRIMBLE. Senator, we are relying primarily not on that letter to which you refer, but on the provisions of section 2 which provide, among other things, that charges for rights-of-way must be just and reasonable, and this is an assurance, in our view, adequate to prevent the government of British Columbia from imposing unreasonable charges for the issuance of rights-of-way for the pipeline through their territory.

Senator STEVENS. Well, I don't think my Canadian neighbors to the south are going to be unreasonable. I just don't think they are going to act by any specific date. And I don't think you have got any specific date in here that they will have to act by. And I don't know what the pound of flesh you are going to get this done, but I know them pretty well. They are going to get one.

I don't think you people who have negotiated this agreement did a very good job for Alcan or for the United States in not tieing down British Columbia in view of the history of British Columbia.

Mr. BOSWORTH. Senator, we have a commitment from the Federal Government of Canada that all the authorizations, rights-of-way will be issued in order that the construction in the Yukon and in the Provinces can commence by certain dates. That does not specify the date by which the authorizations must be issued. But they must be issued before the dates of construction.

We would consider that to be an undertaking by the Canadian Federal Government.

In addition, the Canadian Federal Government has assured us that they have the requisite understandings and agreements necessary from the Canadian Provincial governments.

Senator STEVENS. My friends in the Canadian Parliament told me, and I have told those of you who are negotiating this agreement, that it would be necessary for the Provinces, the Provincial Governments, to ratify that treaty. And we didn't require that, did we?

Mr. BOSWORTH. No, sir. The Canadian Federal Government says it is not necessary for the Canadian Provincial Governments to ratify the treaty.

Senator STEVENS. I understand. They say we have agreed. We have told you what will happen; now it will happen. Now, if it doesn't happen, what are you going to do to them?

Mr. BOSWORTH. Well, we have, in effect, commitments from the Canadian Federal Government under international law.

Senator STEVENS. All right. Suppose British Columbia doesn't give you the right of way by the timetable in this agreement, what are you going to do? What is Alcan going to do?

Mr. BOSWORTH. We would then, I presume—it would depend upon the circumstances of that particular time, but we have a binding arbitration clause in the Canadian Gas Pipeline Agreement.

There are consultation procedures under this agreement on principles and the Canadian Federal Government has assured us that this will not be the case; that they will, in fact, issue or insure that all of the rights of way, authorizations, et cetera, are issued in time for the construction to commence prior to the States.

Senator STEVENS. Well, I pray to God you are right. We are going to leave this issue, but I pray to God you are right.

I know British Columbia better than Ottawa does apparently, because they don't even read the papers out in British Columbia. What they are saying, they are in no rush to do this. And they have not gotten their pound of flesh yet and they are going to get it.

One of their people mentioned $842 million. Another one mentions paving the Alaskan Highway at our cost. That is at the cost of the users of the pipeline.

This British Columbia statement, as I understand it, is in the form of a letter from the current Provincial Governor; is that correct?

Mr. BOSWORTH. That is my understanding. Yes.

Senator STEVENS. Was it ratified by the parliament of British Columbia?

Mr. BOSWORTH. I believe it is a communication between the Provincial Government and the Federal Government. I do not believe it would be ratified.

Senator STEVENS. I think some of you people better start studying what is going on over there because that governor can be changed awful fast, but the parliament can't. Not that fast.

Would you take a letter from the Governor of the State of Alaska saying of course the State of Alaska is going to pledge $900 million? Would you take that letter and accept it as being binding?

Or would you require that the legislature of the State of Alaska authorize him to make the statement?

Mr. BOSWORTH. I don't think that the Government of British Columbia has pledged money. That is not the issue.

Senator STEVENS. Oh, but they have pledged—they didn't pledge anything. They say that they are prepared to cooperate to insure the provisions with respect to this pipeline treaty adhered to, but subject to the position expressed in a telegram of August 31, which, incidentally, Mr. Schlesinger told this committee and my State they could have a copy of, and you apparently say that we are not going to be getting a copy of it; is that correct?

Mr. BOSWORTH. That is correct, Senator. The Canadian Federal Government has told us that that telegram relates to matters which are solely under the jurisdiction of the Provincial and Federal Governments.

Senator STEVENS. Did the State Department see that telegram?

Mr. BOSWORTH. No. I have not seen that telegram.

Senator STEVENS. But you are prepared to accept their statement that what is qualified by telegram that we are not to see?

Mr. BOSWORTH. We have what we consider to be, Senator, a statement of binding commitment from the Canadian Federal Government.

Senator STEVENS. Well, I hope it is. I hope your trust is well placed, particularly if you have bought the Alaska Highway as an indication. Have you ever driven the Alaskan Highway?

Mr. BOSWORTH. No, I have not.

Senator STEVENS. Did you know we are paving it right now for the first time between Haynes and Whitehorse and up to the border at the expense of the United States? Did you know that?

Mr. BOSWORTH. No, I did not.

Senator STEVENS. Did you know that they have refused to pave it in the past through their country?

Mr. BOSWORTH. No, sir.

Senator STEVENS. All right. Well, I would advise you to drive it, particularly in the springtime and just see how much cooperation we have had.

At one time I lost three new tires, Double Eagles, on one trip, going through that road that has got such a great history of cooperation.

I will be a little bit shorter with Mr. Altman.

Mr. Altman, I want to thank you personally for your cooperation with our State and I say so publicly as a Republican that I think—whether it is embarassing to you or not coming from a Republican—

that you are a bright young man in a new administration and I hope you are listened to.

I do have a little problem, however.

Mr. ALTMAN. Thank you, sir.

Senator STEVENS. You have suggested that our State should put up $900 million to give the guaranteed sum of financing for a pipeline we didn't want. Did you ask our State if we would do that?

Mr. ALTMAN. First of all, Senator Stevens, I appreciate your kind remarks. It is very nice of you. Our position, Senator, is not that the State must do anything——

Senator STEVENS. But I read between the lines here when you are talking about establishing a field price that perhaps you might think or someone in the government might think that Alaska may see—might have an offer it can't refuse in connection with this guarantee.

Is that implied here at all?

Mr. ALTMAN. No, sir. I don't really think that it is.

Senator STEVENS. I am sure you know, for instance, that the company hasn't made an application, to my knowledge, for right-of-way across State lands.

Mr. ALTMAN. Yes, sir.

Senator STEVENS. And I am sure you know that it is State gas that they are pumping from State lands.

Mr. ALTMAN. Yes, sir.

Senator STEVENS. And that our regulatory commission can set the rate at which that gas is produced and our right-of-way people can be just as hard as British Columbia about what the terms are of going across our State land. So you wouldn't want to imply at all that the State has got an offer here that we are not going to be able to refuse.

Mr. ALTMAN. No. I think that is clearly that the financing participation, if any, by the State is purely an intrastate matter. Our view is simply that it would, for obvious reasons, facilitate the overall financing of the project.

In addition, we do think, Senator, that if necessary the State ought to participate in the financing before the general taxpayer of the United States would participate.

Senator STEVENS. Why is that? You know, we calculated it and the return to the United States is going to be something like 100 times the amount that is the potential return to our State. And ours is the ownership interest. And a tax interest return in the Federal Government is solely a tax interest return.

Why is it you take the position that the public assistance from the Federal Government is going to have this tremendous income from this project is wrong, but the State should be in a position of doing so because it is going to derive some returns, both tax and royalty interest?

Mr. ALTMAN. Senator, as I discussed briefly in my testimony, we think there are a whole series of reasons why the direct financing assistance at the Federal level; namely, general taxpayers supporting the project, has not been assessed.

Senator STEVENS. But don't you think they apply to our State, too? I think ideally the thrust of your remarks, I agree with. Namely, that this project would be financed on a purely conventional basis and that the financing participation by the State wouldn't be necessary since your State would get the benefits of this project, the industrial development projects and others without participating in the financing.

Mr. ALTMAN. I am not sure——

Senator STEVENS. But we are going to have to pay for the transportation of gas. We are no different if we have an industry in Fairbanks that gets gas from this project, it is no different than one in Chicago. Why does this put us in any different position?

Mr. ALTMAN. Let me simply reiterate, Senator. It is not our position that the State must participate. I don't agree that—I don't even imply that this is being orchestrated in a way that would present the State with an offer it can't refuse. That is not the point I am trying to make or that we are trying to make.

Senator STEVENS. I would like to tell my friends—it is like trying to trap a polar bear by the tail. He doesn't have a very long tail. I have never known anyone to succeed in holding one.

I would not make that—I mean I am serious. I hope no one downtown thinks they can find a way to give us an offer we can't refuse with regard to this gas.

My last question to you is—I don't notice any comment in here about the gas-conditioning plant. Has the Treasury looked into the problem of gas-conditioning plant costing \$2½ to \$3 billion. Who is going to finance it?

Mr. ALTMAN. To some extent, yes, Senator. Probably the Department of Energy has the experts on the technology involvement.

It is our understanding that gas-conditioning costs which are very large for that plant, which would be the responsibility of the producer.

Senator STEVENS. Of the gas or both?

Mr. ALTMAN. Both.

Senator STEVENS. They are going to take a gas—they are going to take associated gas as produced with the oil. That gas contains liquid hydrocarbons, and there will be temporary separators when the oil comes out of the ground. It will then be transported in pipelines and sent to a gas-conditioning plant.

That gas-conditioning plant will take off the liquid hydrocarbons plus the carbon dioxide, plus the sulfur, plus a few other things. I read the numbers yesterday, but the quantities were staggering.

It is my understanding that the liquid hydrocarbons go in the oil pipeline, and the dry gas would go in the gas pipeline. Why is not this a time to decide that the users of the liquid hydrocarbons are going to pay something that will be going in the old pipeline and the users in the gas pipeline are also going to pay?

In other words, this suggests the keystone of the whole North Slope system, and shouldn't that cost be separated between the users of the liquid hydrocarbons and the users of the gas?

Mr. ALTMAN. Senator, I probably should supply an answer of that for the record. And I will. But I would just say I think the gas-conditioning costs associated with this project are the responsibility of the producers and in terms of dividing participation of the type user items that the new Federal energy regulatory commission will be involved in deciding that, but I would prepare an answer for the record on that.

[The information follows:]

THE DEPARTMENT OF THE TREASURY,
Washington, D.C., October 25, 1977.

Hon. HENRY M. JACKSON,
Chairman, Energy and Natural Resources Committee,
U.S. Senate, Washington, D.C.

DEAR MR. CHAIRMAN: I appeared before your Committee on October 12, 1977, to represent the Treasury Department in support of the President's Decision on an Alaska Natural Gas Transportation System. This letter is in response to Senator Stevens' question regarding the gas conditioning facilities.

The gas conditioning controversy revolves around the question of which parties will own and operate the facilities needed to process the gas so that it meets the technical standards required by the Alcan pipeline. Reliable cost data for these facilities are not available, but the producers have claimed costs could range as high as $2 billion. Throughout the review process mandated by the Alaska Natural Gas Transportation Act of 1976, these conditioning costs have not been considered as a cost of the transportation system. In the lower 48 States, such facilities are sometimes provided by the producer and sometimes by the purchaser.

The issue now clearly falls within the purview of the Federal Energy Regulatory Commission, which has the authority to resolve this issue when presented with the question. I assume that the interested parties will request some form of "interpretive ruling" from the Commission in the near future, because, of course, the issue must be resolved before sales contracts can be negotiated.

I hope the above information serves to clarify the process by which the gas conditioning issue can be resolved, and I ask that you insert this letter into the official hearing record so that it may be complete.

Sincerely,

ROGER C. ALTMAN.

Senator STEVENS. I appreciate that. I think it is time for some innovative thinking if you want the State to participate in that. If we do use some innovative thinking, I will help you.

Mr. ALTMAN. Thank you, sir.

Senator STEVENS. Thank you.

Senator ABOUREZK. Thank you.

[The prepared statement of Mr. Altman follows:]

STATEMENT OF HON. ROGER C. ALTMAN, ASSISTANT SECRETARY OF TREASURY FOR DOMESTIC FINANCE, DEPARTMENT OF THE TREASURY

Mr. Chairman and members of the committee, I am pleased to have this opportunity to assist you in your consideration of the President's Decision on an Alaska Natural Gas Transportation System, and, in particular, the financing aspects of the Decision.

The Treasury Department has participated in the Alaskan gas decision process from its initial stages. Among other activities, the Department led an interagency task force, which on July 1, 1977, delivered a public Report to the President on financing a transportation system.

The President has designated the Alcan system to transport Alaskan gas across Canada for delivery to consumers in the lower forty-eight states. The President's Report discussing the reasons for that decision was forwarded to Congress. It included a detailed discussion of the financing issues. Let me begin, Mr. Chairman, by summarizing the discussion of financing contained in that Report.

The President observes that "the Alcan project will be one of the largest—if not the largest—privately financed international business ventures of all time." Obviously, the amount of financing required for such an undertaking is enormous and raising it is a complex task. Indeed, certain financing issues still remain unresolved. My central conclusion, however, is that the Alcan project can be privately financed, assuming equitable participation of those parties who will benefit directly from its construction.

FEDERAL REGULATION

The Treasury Department has consistently argued that an Alaska Natural Gas Transportation System could be privately financed given a proper Federal regulatory climate. The President's Decision, with the accompanying Terms and

Conditions, would eliminate much of the potential uncertainty of Federal regulation and ensure that such regulation will be conducive to both an efficient project and a private financing.

To be specific, the President has recommended a modified form of incremental pricing for Alaskan Gas to assure marketability to consumers. He has recommended the creation of an Alaska Natural Gas Office directed by an appointed Federal Inspector to coordinate the government's involvement in construction of the project and to ensure the project proceeds efficiently. He has prepared an Agreement with the government of Canada which largely eliminates binational regulatory problems. The President has recommended establishing a rate of return on equity which discourages cost overruns. He has discouraged the use of new and controversial tariff arrangements that would be subject to time-consuming litigation with uncertain results. Finally, the President has recommended that the field price to the producers of Alaskan gas be established in accordance with his National Energy Plan, thus eliminating a lengthy price proceeding before the Federal Energy Regulatory Commission and subsequent litigation.

By adopting these recommendations, the Carter Administration expects to resolve much of the uncertainty which earlier characterized the Federal regulatory environment for this project. This should eliminate what had been perceived to be a major risk of the project. In effect, the President's recommendations go far to encourage an economically viable Alaskan gas project, which is the key to a private financing.

One of the issues mentioned above, the form of the tariff paid by gas consumers, is particularly central to financing the project privately. The project applicants originally requested a novel form of tariff referred to as the "all events, full cost of service" tariff. This tariff would have reimbursed the project company for its costs, including the return on and of equity, under any and all possible circumstances, including non-completion. It was argued such a tariff was necessary to induce sufficient private lending for this project.

Alcan's financial advisors have recently concluded that such a tariff will not be necessary. Alcan is prepared, instead, to finance its project with a more conventional tariff comemencing only after the project has been completed. Such a tariff would assure that the project's debt would be serviced upon completion and should satisfy lenders that principal and interest payments on the project's debt will be met.

Essentially, our anticipation of an economically viable project coupled with this assurance of debt service leads me to believe that the Alcan project can be financed in the private sector.

ALCAN FINANCING PLAN

Alcan's financing plan, which is included in the President's Report estimates the total capital requirements of the project at $9.7 billion in escalated dollars, most of which is to be raised over a three year period beginning in 1980. Of this total, 22 percent will represent equity investments and 78 percent will be in the form of debt capital. Alcan expects approximately 82 percent of this $9.7 billion total ($7.9 billion) to be raised in the U.S., and the remaining 18 percent ($1.8 billion) to be raised in Canada.

The U.S. and Canada private capital markets combined represent the largest and most resilient capital markets in the world and have the inherent capacity to supply these amounts. As an example, Alcan plans to raise approximately $5.5 billion during three years in the U.S. corporate long-term debt market. Overall long-term borrowing by nonfinancial corporations in that market is projected to reach $300 billion this year. In 1982, the final year of Alcan's borrowing, it is projected to increase to $466 billion. Alcan's borrowings would represent only 1.2 percent of this total.

The Alcan financing plan should be viewed as tentative because several important issues must be resolved before funds will be committed to it. These currently unresolved issues include:

1. The final determination of the field price of Alaskan gas;
2. The completion of sales contracts for the gas; and
3. The final determination of the rate of return that will be allowed on the equity investment in the project.

A small group of the largest U.S. insurance companies will provide the bulk of the U.S. dept capital required. Accordingly, their perceptions of the risks will be critical.

At this initial stage, we cannot be sure how these key lenders will assess the risks or even which risks they will perceive as dominate, e.g., the risks of marketability and non-completion. It will take more than a year before we will know with certainty whether the financing can be arranged.

PARTICIPANTS IN A PRIVATE FINANCING

One important aspect of our conclusion on the private financing is that the parties who benefit from the project can and should participate in its financing. The major and direct beneficiaries of this project are natural gas transmission corporations, the producers of North Slope natural gas, and the State of Alaska. Their participation will increase the overall private financeability by reducing the amounts which must be raised on the strength of the project's credit alone. I will discuss each of these parties briefly.

NATURAL GAS TRANSMISSION AND DISTRIBUTION CORPORATIONS

Natural gas transmission and distribution corporations comprise the Alcan consortium and they must provide the necessary equity for the project as well as the equity portion of any cost overrun financing. The strength of this sponsoring consortium, therefore, is a key element of the financing. Our analysis shows that the firms currently involved in the Alcan project have the capacity to provide these required equity investments. Furthermore, we expect that the consortium will continue to expand and eventually will include a large portion of the entire natural gas transportation industry. In addition, the Alcan project has the advantage of the substantial equity investment of Canadian transmission corporations, which will total at least $800 million.

PRODUCERS OF ALASKAN NATURAL GAS

The owners and producers of Alaskan natural gas are major U.S. energy companies. This group is primarily composed of Exxon, Atlantic Richfield, and the Standard Oil Company of Ohio. These companies will benefit substantially from the sale of their natural gas reserves, and obviously require a transportation system to sell them.

These three companies had total assets of $51 billion in 1976 and net income in excess of $3 billion. They clearly have the capacity to participate in the financing of a transportation system, especially as full returns from their North Slope oil and related pipeline investments are realized. These companies have demonstrated varying degrees of interest, however, and they should be encouraged to do so. We think that financial participation by the producing companies can be structured so as to avoid anticompetitive practices, a continuing concern of the Department of Justice. This issue is specifically addressed in the Report which has been forwarded to you with President Carter's Decision.

THE STATE OF ALASKA

The State of Alaska will realize substantial revenue in the form of royalty payments and taxes from the sale of North Slope gas. The State will also benefit from use of the pipeline for natural gas distribution and resulting commercial development within the State.

The State of Alaska can use a portion of its revenues from the sale of Alaskan oil to assist in the financing of this project. Originally, the State offered to assist in the financing of the El Paso project by guaranteeing $900 million of project debt. Similar State of Alaska support for the Alcan project is considered advantageous and is encouraged.

FEDERAL GOVERNMENT FINANCIAL ASSISTANCE

Possible Federal government support to the project, viz., loan guarantees or insurance, has been evaluated intensively by the Treasury Department because certain parties earlier claimed that it was necessary. These parties asserted that Federal financing support was necessary to finance the project in the uncertain regulatory environment which then existed. They argued that only such assistance would assure lenders of repayment in the event the project was not economically viable and only this would assure their participation. In particular, the Arctic Gas consortium, which withdrew earlier, claimed that financing assistance by both the Canadian and U.S. governments was required for the financing of their project. In addition, the El Paso proposal incorporated approximately $1.5 billion in loan guarantees under the existing Maritime Administration Shipbuilding program. On the other hand, no Federal financial assistance has been requested for the Alcan project.

Alcan's investment banking advisors do not believe that Federal financing assistance is necessary for the Alcan project. The Administration shares this conclusion. In addition, the Administration believes that Federal assistance to this project would be undesirable for several important reasons.

1. Federal financial support substitutes the government for private lenders in the critical risk assessment function normally performed by the private lenders.
2. Financial assistance also reduces incentive for efficient management of the project.
3. Serious questions of equity would result from the transfer of project risks to taxpayers, many of whom are not gas consumers or will not receive additional gas supplies as a result of the Alaskan project.
4. A subsidy in the form of lower interest rates yields an artificially low price for the gas.
5. Other large energy projects might not be undertaken without similar Federal assistance.

The Government of Canada also opposes Canadian governmental financial assistance to a binational project.

TRANSFER OF FINANCIAL RISKS TO CONSUMERS

The issue of a new mechanism by which gas consumers bear some or all of the financial risks of this project also has received careful study by the Executive Branch. The most frequently discussed mechanism for consumer support would entail a consumer financial guarantee by means of an all events tariff with non-completion arrangements. The non-completion features would provide for a consumer guarantee of at least debt service in the event of non-completion.

The Alcan sponsors and financial advisors have stated that the Alcan project can be financed without such a consumer guarantee prior to completion and without Federal financial assistance. The Administration has concluded that the bearing of financial risks by consumers prior to completion is unnecessary for this project. Furthermore, the Administration believes that consumer guarantees are undesirable for many of the same reasons that Federal financing assistance is undesirable.

CONCLUSION

The Alcan project is the largest construction project ever contemplated by private enterprise. The requisite financing is uniquely large, complex and most difficult. Let me emphasize, however, that the Administration currently believes that this project can be financed privately—that is, without Federal financing assistance or consumer guarantees. We encourage appropriate and equitable financial participation by the parties benefiting directly from the project. In conclusion, I urge Congressional approval of the President's Decision recommending the Alcan project.

Senator ABOUREZK. I want to ask the staff counsel, Betsy Moler, to put some questions to the panel, but before I do that, I was just advised that one of the members of the panel is Mr. Phil Trimble—is that right?

Mr. TRIMBLE. That is correct.

Senator ABOUREZK. Were you the same Trimble who led the U.S. team up Mount Everest last year?

Mr. TRIMBLE. Yes, Senator. I am.

Senator ABOUREZK. And you made it to the top?

Mr. TRIMBLE. We put two people on the top just about 1 year ago.

Senator ABOUREZK. I wonder, then, if you would give us a comparative observation on the difficulty of climbing Mount Everest and then climbing Capitol Hill?

Mr. TRIMBLE. I thought you were going to ask for a comparison of the difficulties of negotiating with the Canadians.

Senator ABOUREZK. That is his department.

Mr. TRIMBLE. All three are roughly comparable.

Senator ABOUREZK. I guess we ought to congratulate you for your efforts.

Mr. TRIMBLE. Thank you, Senator.

Senator ABOUREZK. Betsy.

Ms. MOLER. Mr. Bosworth, the agreement assumes that the Canadian Government will pass legislation to settle the land claims. When will that legislation be taken up?

Mr. BOSWORTH. The agreement does not assume that the Canadian Parliament will pass legislation. The Canadians have said that the settlement of the native claims is an internal Canadian matter and how they do it is up to the Canadian Government. They may or may not require legislation. We don't know that at this point.

However, we do have the Canadians, as I indicated earlier, committed to a firm time table for the issuance of permits, et cetera, to enable construction to go forward by the dates as set forth in the agreement.

Ms. MOLER. If they choose not to pass legislation, what other avenue would be available to them to settle their claims?

Mr. BOSWORTH. I really can't answer that question at this point. I would be glad to supply something for the record on the way in which conceivably options under which the Canadians could settle native claims. But the position that the Canadians have taken on this issue is that that is not directly relevant to the agreement between the United States and Canada since the settlement of native claims is an internal Canadian matter.

Ms. MOLER. Senator Stevens questioned you earlier about the agreements to be negotiated between the Provinces and the Federal Government. Do you have a timetable on when these agreements are to be negotiated? Do we understand they are being negotiated presently?

Mr. TRIMBLE. If I may address that. The Federal Government was consulting with the Provinces throughout the negotiation of this agreement and we are in the process of negotiating these documents at that time.

I assume that they are continuing that process so it will be completed within a relatively short time frame.

Ms. MOLER. If the agreements are not negotiated and finalized, is the whole deal off as far as the President's recommendation is concerned?

Mr. TRIMBLE. No. We regard the Canadian Federal Government as responsible for carrying out the commitments that it has undertaken in this agreement. How they implement those commitments, whether it is through a formal agreement with the Provinces or through some other means is up to them.

Ms. MOLER. If, for some reason, the Canadian Government is unable to carry out its half of the agreement, what happens?

Mr. TRIMBLE. We regard the Canadian Federal Government as responsible for the consequences. I am afraid there is no international court that we can haul them into and levy on their assets.

But we would expect them to carry out their undertakings in these agreements and if they are unable to do so, to take care of the consequences.

Ms. MOLER. It was my understanding that there was an understanding among those who negotiated the agreement that if one or the other of the governments were unsuccessful in implementing its half of the deal, that it was implicit that the whole thing would fail; is that not correct?

Mr. BOSWORTH. It is clear that both governments have legislative processes which have to be completed with regard to the agreement. Ours and the natural gas pipeline legislation that the Canadians would regard, the extent to which they are modifying or changing the original recommendations of the National Energy Board.

Now, if one or the other of those legislative processes is not completed, then clearly we are back to the drawing board.

Ms. MOLER. The decision contemplates the Federal Energy Regulatory Commission will set a rate of return based, in part, on cost overruns. FERC will obviously have to have access to all the appropriate documents, including documents that will be solely in the possession of Canadian companies.

Is there any way that you can assure us that FERC and other U.S. Federal entities will have access to Canadian companies' relevant documents?

Mr. BOSWORTH. As you point out, Ms. Moler, the FERC will require in order to approve the rates, et cetera, set to the Canadian portion of the line will require documentation. There is a provision in the agreement for full and regular consultation between our regulatory authorities and the Canadian regulatory authorities.

We have not specified any of the things that will be consulted upon, but clearly that is one of the relevant points of consultation.

Ms. MOLER. So it is your interpretation of the agreement that we will coordinate with FERC through the NEB or whatever appropriate Canadian entity will have access to the documents on costing and contracting procedures and so on of Alberta Gas Pipeline, for example?

Mr. BOSWORTH. Yes. They would clearly require all of this information in order to make a decision.

Ms. MOLER. Mr. Altman, on page 1 of your statement you conclude that the Alcan project can be privately financed, assuming the equitable participation of those parties who will benefit directly from its construction. Are you using equitable as a term of art, therefore, advocating that the State of Alaska will buy an equitable position in the pipeline?

Mr. ALTMAN. No. I am only pointing out the extent, the financeability, the private financeability of the project is somewhat proportionate to the participation of the producers in the State of Alaska. We don't view that participation, as I said later in my testimony, as financing this project. But the project's financeability is enhanced quite measurably so by the participation of the producers or the State or both.

I am not talking about equity in the financial sense.

Ms. MOLER. If the producers and/or the State do not participate in the financing, do you believe that an all-events tariff is necessary or that it would be privately financeable?

Mr. ALTMAN. No. Even absent the participation of the two parties and absent a so-called all-events cost-of-service tariff, that the basic economics of the project, particularly the regulatory regime, which will govern it, will be sufficient to permit any finance without resorting to direct Federal participation.

Ms. MOLER. The calculations in the President's decision showing that it is financeable, were based upon a throughput of 2.4 BCF per day. That throughput includes the State of Alaska royalty gas.

If the State of Alaska chooses not to commit its royalty gas to the pipeline, do you still believe it is privately financeable?

Mr. ALTMAN. Yes; we do. It seems to me that that gas, if not documented through the pipeline, is gas that will be paid for by those— by the entities in the State of Alaska which use it and that does not sharply diminish the basic economics of the project. It would not change our basic judgment on the financeability.

Senator STEVENS. Even if one-eighth of the gas were not committed?

Mr. ALTMAN. No. Because it is gas that would be paid for anyway. And in addition, my understanding, Senator Stevens, I am sure as illustrated in my remark, is that even at the high end of the range of estimates, which is the gas that might be used within the State for productive development in its normal uses, is not in the range of the length of the overall gas.

Something like one-third of that.

Senator STEVENS. The State has informed me it has applications for industrial use that will consume 100 percent of the one-eighth.

Mr. ALTMAN. I stand corrected, sir. I am glad I referred to you.

We have looked into that somewhat. Not exhaustively at this point. Our conclusion is that it still can be financed because it is not going to be given away. It is going to be paid for. And looking at the product as a whole in its economics, we don't think that they would be so changed as to prevent private financing.

Ms. MOLER. There would be an effect upon the cost of service, obviously?

Mr. ALTMAN. Yes.

Ms. MOLER. The agreement has a complicated formula governing the Yukon property taxes. The formula ties those taxes to the Canadian GNP deflator and the U.S. taxes. Would whoever on the panel cares to, please attempt to explain that for me in English so that the committee can understand its practical effect.

Mr. BOSWORTH. Well, if I can summarize it briefly, Ms. Moler. There is a specific level of taxation set for the years of construction. In 1983 when the pipeline is scheduled to open, the level of the Yukon property tax issue is fixed for the next 5 years at $30 million, plus an escalator which is the Canadian GNP deflator.

In 1988 the tax regime, assuming always that the Dempster Lateral has not been built, because if the Dempster Lateral has been built, that provides a basis for the United States-Canada transit pipeline, and we will not need this alternative tax regime, but if it has not been built by 1988, the level of property taxation in the Yukon is then subject to review against three criteria, one of which is still the Canadian GNP deflator or rate of inflation. The other is the rate of property taxation under the pipeline in Alaska.

The third is the per capita property tax exclusive of the property tax on the pipeline in the Yukon, plus grant to the Yukon Provincial government. Then after 1988, the property tax on the pipeline in the

Yukon will be fixed at the highest of those of the rates produced by those three criteria.

That property tax regime lasts for a total of 25 years.

Mr. TRIMBLE. It goes to 2008.

Ms. MOLER. So if the State of Alaska Legislature increases the Alaska property tax on all pipelines, the Yukon tax level could be increased as well?

Mr. TRIMBLE. Yes. If Alaska increases the property tax rate on the gas pipeline.

Ms. MOLER. Does it have to be solely on the gas pipeline, or can it be on the TAPS line as well?

Mr. TRIMBLE. Let me just check that, but I believe that the Alaska adjuster is computed with reference solely to the Alaska property tax on the gas pipeline. So it would have to be—at least the annual—there are two adjustments for the Alaska—two adjustments made with regard to the Alaska property tax.

There is a one-time adjustment in 1983, and that adjustment is made with reference to the Alaska property tax on pipelines in general. That would include the oil pipeline. The annual adjustment thereafter is fixed solely with the Alaska property tax on the gas pipeline.

Ms. MOLER. Thank you very much, Mr. Chairman.

Senator BARTLETT [presiding]. Does that complete the questions that you have, Senator Stevens?

Senator STEVENS. Yes.

Senator BARTLETT. Gentlemen, thank you very much.

STATEMENT OF ROBERT BATINOVICH, PRESIDENT, PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, AS PRESENTED BY FREDERICK E. JOHN

Senator BARTLETT. Our next witness will be Frederick E. John, director of policy and program development for the Public Utilities Commission in San Francisco, Calif.

You have the statement of Robert Batinovich.

Mr. JOHN. Yes, Mr. Chairman.

My name is Frederick John. I am director of policy and program development for the California Public Utilities Commission. I am here on behalf of Robert Batinovich, president of the public utilities commission.

President Batinovich expresses his apologies for not being able to be here today, but we had a commission conference today on several very important matters on the agenda as far as the gas consumers of California are concerned. I am here in his behalf. The statement I am about to read is being made on behalf of the State of California.

On September 22, 1977, President Carter transmitted his decision and report to Congress on the Alaska natural gas transportation system as required by section 7 of the Alaska Natural Gas Transportation Act of 1976. The President's decision favors approval by Congress of the Alcan project to transport natural gas from the North Slope of Alaska to the lower 48 States via Canada.

Almost simultaneously with the transmittal of the President's decision to Congress, El Paso Co., the sponsor of the El Paso Alaska project—the only remaining competitor to the Alcan project—dropped its proposal to transport North Slope gas to the lower 48 States.

Therefore, for all practical purposes the Congress has before it for consideration only one proposal to transport North Slope gas to the lower 48 States. Of course, this fact should not deter the Congress from determining whether the Alcan project, as presently structured, provides the natural gas consumers of the United States with a viable, economically efficient and environmentally sound method of transporting North Slope gas to lower 48 markets.

California is prepared to comment briefly on those portions of the President's decision which most directly affect the interests of California's gas consumers.

A. Approval of Alcan Project. In the proceedings before the Federal Power Commission relating to an Alaska Natural Gas Transportation System, the California Public Utilities Commission and the California Energy Commission supported the construction of an overland transportation system through Canada, as opposed to an LNG delivery system, to transport North Slope gas to the lower 48 States. Therefore, we find no fault with the President's choice of Alcan over the El Paso-Alaska project.

B. United States-Canada Agreement in Principle. California is favorably impressed with the contents of the agreement between the United States and Canada with respect to the portion of the Alcan project to be constructed in Canada. The agreement seems to provide a reasonable compromise considering the conditions originally proposed by the NEB and the various Canadian governmental study groups.

Hopefully, by the time final certification of the various segments of the Alcan project occurs in late 1978 or early 1979, the Canadian Government would have taken major steps to settle the native claims in the Yukon, and the provinces of Alberta, British Columbia and Saskatchewan would have signed form agreements with the Canadian Federal Government supporting the United States/Canadian Transit Treaty.

C. "Western Leg" Delivery Facilities. California fully supports those portions of the President's decision dealing with the construction of "western leg" facilities to deliver North Slope gas and potential additional supplies of Canadian gas—even prior to delivery of North Slope reserves—to markets west of the Rocky Mountains—Decision, pp. viii, 5, 9, 10, 14, 15, 16, 19, 20, 21, 40, 217–234, 236.

California submits that the approach taken by the President complies with the mandate of section 5(b)(1) of the Alaska Natural Gas Transportation Act of 1976 that the transportation system for North Slope gas which is ultimately chosen—

> include provision for new facilities to the extent necessary to assure direct pipeline delivery of Alaska natural gas contemporaneously to points both east and west of the Rocky Mountains in the lower continental United States.

Further, the President's decision regarding "western leg" facilities would make it possible for areas east and west of the Rocky Mountains to obtain direct access to Canadian gas reserves prior to the time the proposed transportation system is ready to deliver natural gas from the North Slope of Alaska.

Finally, the President's decision would allow California to support the abandonment of a portion of the existing natural gas pipeline system owned and operated by El Paso Natural Gas Company for conversion to a crude oil pipeline system as part of the proposed SOHIO West Coast to Midcontinent Pipeline Project—SOHIO Project—to transport Alaska North Slope oil to the midwestern and gulf coast areas of the lower 48 states, provided the Federal Energy Regulatory Commission makes a reasonable determination as to the fair market value of the facilities to be abandoned.

D. Pricing of North Slope Gas. The President's decision urges that Alaska North Slope gas be classified as "old gas under a new contract" subject to a $1.45 per mcf ceiling price, as specified in his proposed National Energy Act.

California agrees with the President's concern that deregulation of the price of North Slope gas would result in serious uncertainties and delays concerning the development of an Alaska natural gas transportation system, as well as a strong possibility that this gas would not be financeable.

In order to guarantee the marketability of North Slope gas, California submits that the price of the North Slope gas entering the Alcan pipeline system should not exceed $1.45 per mcf.

Unless this ceiling price is maintained, the President's goal of delivering North Slope gas "below the cost of imported oil and substantially below the cost of other fuel alternatives" cannot be met.

In this respect, this Committee should take notice that in his initial decision in the FPC proceeding relating to the transportation of North Slope gas to the lower 48 states, Administrative Law Judge Nahum Litt indicated that a field price of $1.00/MMBtu—based on 1975 dollars—at the inlet of the transportation system—i.e., after gathering and conditioning—was "close to the maximum that this gas could command in the field and still be marketable under present market conditions".

Judge Litt stressed that there would appear to be a substantial return to the producers from a total field price at or below $1.00/MMBtu.

Further, in its recommendation to the President, dated May 1, 1977, the FPC indicated that a field price of $.50/MMBtu—based on 1975 dollars—was supportable. This price would include the cost of gathering and conditioning with a 15 percent discounted cash flow after tax rate of return on incremental investment related to gas production.

According to the FPC, if recovery of some joint oil/gas costs—gas in the Prudhoe Bay field is associated gas—the field price of the North Slope gas might be higher, but no amount was specified by the FPC for joint oil/gas costs.

Assuming a field price of $1.45 per mcf at the inlet of the transportation system on the North Slope, the average cost of North Slope gas during the first 5 years of operation would be $3.16 per mcf—based on 1975 dollars. At this price, North Slope gas would be significantly higher than the Btu equivalent world market price of crude oil based on 1975 dollars.

California urges that Congress decide the issue of pricing North Slope gas in the near future so that the producers and the State of

Alaska can proceed to enter into gas purchase contracts with the putative shippers at the earliest possible time.

California also strongly urges that in determining the price of North Slope crude, Congress recognize that a maximum field price of $1.45 per mcf would provide ample profits to the North Slope producers and the State of Alaska and would provide sufficient incentive to the producers for future development of the North Slope and for some type of financial support of the Alcan project.

E. Financing of Alcan Project. During the FPC proceedings relating to a North Slope gas transportation system, California alleged that without financial participation by the producers and the State of Alaska, some form of Federal financial participation would be required for any North Slope transportation system.

California also suggested that because of the capital intensive nature of this project Federal financial participation might be required in addition to financial participation by the North Slope producers and the State of Alaska.

The President's decision seemed to confirm California's position that financial participation by the North Slope producers and the State of Alaska was needed to assure private financing of the Alcan project.

The President's decision concludes that the Alcan project, both in the United States and Canada, can be privately financed on the following conditions:

1. The equity investment in the project would be placed at risk under all circumstances and the budgeted equity investment be considered the first funds spent. The rate of return on equity would compensate sponsors for bearing this risk.

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

3. The burden of cost overruns be shared by equity holders and consumers upon completion through the application of a variable rate of return on common equity.

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

The decision further states that:

> The Alcan sponsors and financial advisors have stated the Alcan project can be privately financed. The financial analysis above supports this conclusion. Therefore, it is reasonable to anticipate that the Alcan project can be financed in the private sector.
>
> Novel regulatory schemes to shift this project's risks from the private sector to consumers are found to be neither necessary nor desirable. Federal financing assistance is also found to be neither necessary nor desirable, and any such approach is herewith explicitly rejected.

The feasibility of the proposed private financing plan assumes capital requirements of $13.2 billion based on projected cost overruns of 32 percent and an operational date of January 1, 1983.

It is especially noteworthy that the President's decision indicates that producers of North Slope gas could participate in financing this expensive transportation system through guaranteeing some portion of the project debt, consistent with the administration's antitrust objectives, especially under a continuing system of price regulation.

California is cognizant of recent statements by Secretary of Energy Schlesinger to this committee and by Mr. Altman's statement this morning that the Alcan project could be privately financed without any financial participation by the North Slope producers or the State of Alaska. It appears that the capital markets will have to decide whether the President's written decision or the Secretary of Energy's oral statements better reflect financial reality.

California must withhold final comment on the concept of a "variable rate of return" for equity sponsors of the Alcan project until the FPC and the NEB have established the methodology to be used in establishing the variable rate of return.

However, California thinks that the "variable rate of return" approach may be a significant method of avoiding excessive cost overruns, as well as avoiding the necessity for consumer prepayments or surcharges prior to operation of the transportation system.

Finally, California agrees with the President's statement to the Congress that any unnecessary delay in acting upon the President's recommendation would greatly increase the cost of the pipeline system. Therefore, California urges the Congress to act expeditiously in this matter.

Thank you for the opportunity to submit this statement.

Senator BARTLETT. Thank you very much, Mr. John.

Senator Stevens, do you have some questions?

Senator STEVENS. Please say to Mr. Batinovich that there is not going to be any delay in approving the President's recommendation. There may well be a long delay because of the nature of the negotiations with Canada and inadequacies of the agreement.

I only wish I had been the one to negotiate with Canada. I tell you, there would have been some specific dates in that agreement and times for completion, not times for an attempt to start construction.

Tell him rest assured we will get it out on the Senate floor and get it approved as fast as we can. From there on I suggest that we pray a little.

Mr. JOHN. Thank you, Senator Stevens.

Governor Brown has called President Batinovich the ambassador to Alaska. I think the Governor would hope that this would help with Canada also.

Senator BARTLETT. Thank you, Senator.

Ms. MOLER. Mr. John, in the past the California PUC has opposed the abandonment of the El Paso gas line before the FPC because of your view that that line is necessary in the future to supply California's gas requirements.

Is your willingness now to consider abandonment based in part upon the western leg commitment of the President's decision?

Mr. JOHN. I think it is much more than a part. I think it is a specific prerequisite of California support. There are two issues. I am just talking about the pipeline. I am not talking about air quality problems in California. But from a gas supply standpoint and from protection of the rate in California there were two issues in the proceeding.

One was we felt very strongly and still do that if the El Paso line was abandoned for use for the SOHIO project, California consumers have to have some assurance of direct access to both North Slope gas and recently discovered Alberta bubble gas.

I feel very strongly about that. And we think that the way the President wrote the section of his decision on the western leg gives California that type of assurance.

The other issue was the rate impact on the gas consumers as a result of abandoning the pipeline and what we really need is the fair market value. And hopefully within the next week the Federal Power Commission will make a determination on that.

Ms. MOLER. The decision is silent on the volume that will be put through the western leg. Is California PUC's position contingent upon any specific volume?

Mr. JOHN. I think on a couple of places on the western leg volumes were specifically mentioned, namely, 669 million feet per day and one other was 700. That was based on the design that the specific gas transmission company and Pacific Gas & Electric Co. had applied for before the Federal Power Commission. That would require a complete looping of the existing BDTBT system from King's Gate all the way to Antioch with 36-inch pipeline.

That, without any compression, would allow up to 700 million cubic feet of gas per day to open the system. We feel that those are the kind of assurances that the State of California and the utilities will seek since they filed that specific application.

Ms. MOLER. So you need a specific commitment or assurance that the 700 million cubic feet per day volume would, in fact, be utilized?

Mr. JOHN. Again, the President's decision was written on a conditional basis. He said based on the circumstances we see today, namely additional supplies from Mexico, additional predelivery of Alberta bubble gas plus North Slope gas if California goes out and contracts for that gas, based on those circumstances here is the design we would approve; between now and 1 year from now, facts may change.

And if at a later time, late 1978 or early 1979, we need a bigger system or a smaller system based on those facts, the Secretary of Energy made that recommendation to the Federal Power Commission. We don't think that we could ask for much more than that because we realize circumstances change.

We didn't think chances of getting Mexican gas existed a year ago or Alberta bubble gas, but things change on a daily basis. So we appreciate the way the President wrote that portion of his decision.

Ms. MOLER. Thank you very much.

Senator BARTLETT. Mr. John, there are some of us who are hopeful that when the curtain comes down in Congress on energy and particularly the price of natural gas, that it will be a free market at some point.

In view of that do you feel that the $1.35 that you mentioned, if the parties were free to negotiate that contract price, that it would be that high or would you think it would be higher or would it be lower?

Mr. JOHN. We don't really know, Senator. Our feeling is in California that notwithstanding what Congress does on deregulation in the lower 48 States, some exception should be made for the North Slope gas and we would urge that even if there was deregulation in the lower 48 gas, some provision be specifically written in, hopefully in the conference committee, to take cognizance of the unusual situation on the North Slope. Namely, the very expensive transportation costs.

Senator BARTLETT. You say something special should be written in intimating then a price limit?

Mr. JOHN. Yes. Assuming that we specify the President's statement, namely, a field price at the inlet of the transportation system no higher than $1.45. We think with that price in the first year of operation based on 1975 costs, we are already talking about $3.16 which is significantly higher than the world market price based on 1975 dollars.

Senator BARTLETT. Senator Stevens?

Senator STEVENS. Mr. Chairman, do you think if that were ever passed that we would allow our State not to be regulated and the rest deregulated? You haven't seen a real filibuster. I would help.

I just want you to know that on deregulation we think the price would be lower and we are willing to pay it, so it doesn't make any difference.

Mr. JOHN. Again, the reason that we brought it to the committee's attention, we felt that statements by Judge Litt and by the Federal Power Commission as to what would it be on a cost situation should be very, very instructive to the committee.

But we also realize that some incentive is necessary to get the producers and, hopefully, the State of Alaska to come in with some kind of financial participation on the project.

Senator STEVENS. All right. I don't have any other comments. Just to say that the national system is a national system and deregulation effect, if they lower the price of Alaska's gas and can't increase it in proportion to that price.

Mr. JOHN. We hope that you are right.

Senator BARTLETT. I would just say that I think those who have favored special price controls—of course, we have been down there in a long time, interstate shipment, that their case was justified, but I think the history of it is shown very clearly that the costs that were used were no replaceable costs and were not sufficient to guarantee us a sufficient supply.

So we are kind of short. And that is the reason we are in this with the Alaska pipeline. For some reason they seem to rely on the judgment of a few people well placed in Washington, rather than thousands and thousands of people who established the price on supply and demand in their decisions.

I think what you are asking for is out of order if—unless that is the law. But I don't think California should have any special consideration, say, on this gas over Oklahoma.

I think we would be glad to have the assurance that there is going to be a Federal supply on that line. It was built for a long time and not just the first year or the second.

Senator Jackson, do you have any questions?

The CHAIRMAN. No. I just arrived. I want to thank you, Senator Bartlett, for helping out here.

Senator BARTLETT. Would you like to sit in this seat?

The CHAIRMAN. No.

Senator STEVENS. When you go home, get that Sohio project approved, then we will be sure to get the gas out.

Mr. JOHN. We recognize that the projects go somewhat hand in hand.

Senator BARTLETT. Any other statement you would like to make?

Mr. John. No, sir. Thank you.

Senator Bartlett. All right. Thank Mr. Batinovich.

Mr. Doscher is here. We would like to receive your testimony; if you don't mind, however, we would like to proceed ahead with the next person, because Senator Durkin wants to hear his testimony, and the Senator has not arrived yet. Our next witness is Mr. Sidney M. Wolf, Assistant Professor, Division of Public and Environmental Affairs Program, Indiana University in South Bend, Indiana, representing the Environmental Policy Center.

I understand that Senator Durkin is expected very soon. As soon as he arrives, you may proceed, Mr. Doscher.

Mr. Wolf, if you would proceed with your testimony, you may either read it or summarize it.

Mr. Wolf. Thank you, sir.

Senator Bartlett. You are recognized immediately.

STATEMENT OF SIDNEY M. WOLF, ASSISTANT PROFESSOR, DIVISION OF PUBLIC AND ENVIRONMENTAL AFFAIRS PROGRAM, INDIANA UNIVERSITY AT SOUTH BEND, SOUTH BEND, IND.

Mr. Wolf. I thank the committee for the opportunity to make a statement on this very important energy, environmental, and let us not forget, consumer issue.

Since the passage of the Alaska Natural Gas Transportation Act of 1976, the Environmental Policy Center has been deeply concerned with the repercussions of this project on the gas consumer. Contrary to the assumptions of many, notably the White House and Alcan, this project is not necessarily in the best interest of the gas consumer.

In fact, under the pricing and tariff measures advocated by Alcan and the White House the Alaska gas project will likely bring down grevious harm upon the gas consumer, the national economy, and our prospects for sound national energy development in the future.

The litmus test of the economic merit of virtually all prospective business ventures in whether sufficient financing from private lenders can be obtained. Reluctance to invest on the part of private lenders implies a venture seeking investment faces serious risks jeopardizing investment.

This is the case with the Alaska gas project. Excessive cost overruns, premature project abandonment after completion, and prolonged service interruptions are very real risks for the Alaska gas project, at least to the critical minds of investors.

Senator Bartlett. Mr. Wolf, if you wouldn't mind, your statement is rather long. If you could summarize to some extent, we would appreciate it. We are not trying to have you reduce the effect of your testimony.

We have two other witnesses.

Mr. Wolf. I will resort to briefer notes.

Senator Bartlett. That will be appreciated. Your complete testimony, as written, will be placed in the record.

Mr. Wolf. Thank you very much.

I have previously noted that in our economy the gas consumer prospects for energy development. Let me indicate—discuss these implications.

The Alaska gas project will have these results if the project overruns enormously and gas consumers are forced to buy the gas no matter how exorbitant it becomes and also to bear much of the financial risk of the project. The risk of excessive overruns and prolonged service interruptions for the Alaska gas project are great.

Private lenders will not invest billions of dollars in the project unless their investments are well protected. Should these risks become a reality, to entice private investment to the Alaska gas project would not otherwise receive, Alcan and the White House propose strong measures to protect debt capital in the project.

First, Alcan and the White House—Second, gas consumers will be compelled to pay the debt charges of the project in the event of prolonged service interruptions and I think possibly premature abandonment of the project after completion, if that is interpreted as a prolonged service interruption.

Third, project sponsors will be allowed a handsome rate of return even if overruns skyrocket to celestial heights for any number of reasons, including gross project mismanagement by Alcan.

We have previous experience of that with the Alaska project. The Alcan project will not run over 800 percent as the only large scale price project with which we have had experience to date, the trans-Alaska oil pipeline. The Alcan project will not even overrun to 300 percent, as did the Superdome stadium built in the warm and friendly climate of New Orleans.

The Alcan project will overrun at least 200 percent from its filed cost. An overrun of this magnitude will result in \$4.50 gas at the city gate, which is wholly uncompetitive with other gas supplies and relative to other forms of energy, chiefly fuel oil and electricity. The cost of Alaska gas will be boosted even higher if well head deregulation becomes a reality during the 20-year life of the project.

Virtually all gas consumers would not voluntarily purchase \$4.15 Alaska gas. Fearing that mammoth project overruns will yield unmarketable Alaska gas, private lenders will not invest in the project unless consumers are forced to purchase the gas no matter what the price.

Incremental pricing gave the gas customers the choice to buy or not buy Alaska gas. And this pricing method is advocated for industrial customers by the White House.

While the pricing for the Alaska gas and the overall majority of gas users, 40 million residential gas consumers, it is deemed absolutely necessary by the White House. This pricing method which advocates high pricing methods like Alaska gas were lower cost supplies and passes them on to gas consumers at a single rate has the effect of forcing to purchase of Alaska gas.

The pernicious effects of pricing for Alaska gas are numerous and alarming. Rolled in pricing would artificially induce the building of a project requiring at least \$13.6 billion of investment capital which is one-half the value of the assets held by the entire gas transmission industry at the end of 1976, and \$30 billion of investment capital if the project overrun runs 200 percent.

The capital structure would be severely contorted by this project. Interest rates would go up, but to what extent depends upon the magnitude of cost overruns and forced gas purchases.

Rising interest rates could dampen economic activity in already weak sectors of the economy, such as the housing industry which is extremely sensitive to interest rates.

Eighty billion dollars of forced consumer purchases over a 20 year period for gas on a 200 percent Alcan project would deprive many sectors of the economy of this vast consumer investment.

Of equal significance, the scores of billions spent on Alaska gas would produce more energy with longer term benefits and less environmental disruptions if invested in energy producing and saving alternatives ranging from residential solar heating, insulation retrofitting, deeper, tighter gas formations and existing producing production ranges, the Devonian shale and combinations of many other alternatives.

These better alternatives are deprived in the same government creating artificial opportunity for attracting enormous amounts of capital and for massive consumer purchases.

Two hundred percent overrun Alaska gas will push up gas prices in general and be a giant step towards raising gas prices to the high levels needed to make cogas and energy imports cost competitive.

If deregulation becomes a reality, high cost gas supplies such as Alaska gas, would generate windfall profits for the producers of lower cost gas through a phenomena called price changing. The price of lower cost gas would tend to run a step behind that of larger volumes of higher cost gas, although the cost gap between the two is much greater than the price gap.

Rolled in pricing for Alaska gas with or without enormous project overruns would cause wasteful consumption and nonconservation of this huge gas find ballyhooed as saving us from the folly of previous wasteful uses of gas.

Averaging high cost Alaska gas with lower cost gas, masks the true cost of Alaska gas and the gas consumer does not find the need to use it frugally. In addition, thrifty gas users are penalized because of cost averaging. They pay for Alaska gas whether or not they want to use it and they pay more for the lower cost gas supplies they actually use.

To protect the investors from prolonged service interruptions, the White House proposed debt service during such an event, and possibly in the event that premature project abandonment after completion, if that is interpreted as a prolonged service interruption.

Major service interruptions are inevitable for the Alcan project, as they had been for its predecessor, the trans-Alaskan oil pipeline. The explosion of pump station No. 8 this year shortly after taps were turned on has significantly curtailed delivery of Alaskan oil for several months.

An outage of the deeply burned Alcan system during the brutally cold and mostly dark winters in Alaska and the Yukon would be impossible to repair promptly, leaving gas consumers to pay the debts for a system not delivering gas when they most need it.

The White House adopts the variable rate of return previously proposed by the FPC. The variable rate of return is meant as an incentive to Alcan to keep overruns down.

Under this proposal return on equity after taxes decreases from a specified maximum level toward a minimum level as project costs exceed the project budget fixed by the Federal Government. The higher the overrun, the lower the rate of return.

However, the effectiveness of the variable rate of return as a check on overruns depends on the level of minimum return allowed. A variable return formula which falls all the way to no return is the most effective.

A minimum allowed return comparable to the project—sponsored customary return is a weak barrier to overruns. If overruns become too difficult to manage, the project sponsors may decide to live with the usual husky rate of return regardless of how costly the gas becomes due to overregulation.

The White House proposes a legal calculation to the FPC. This is a mistake since the FPC previously recommended a minimum allowed rate of return of 11 percent for the Alaska gas project as an average rate of return of the corporate participants in the Alcan project.

Both the minimum allowed rate of return and the rolled in pricing are indirect but strong forms of consumer guarantees for Alcan's project debts since they enable Alcan to repay those debts.

In closing, let me express my greatest fear about the pricing proposed by Alcan and the White House. The fear is a precedent, they said. The Alaska gas project would involve the most massive forced gas purchase and consumer risk bearing for an energy project ever seen.

In the future, energy companies may be reluctant to engage in major energy projects unless the Federal and State governments strong-arm consumers into bearing much of the financial risk of these projects and into purchasing their energy products.

I fear the day when the kind of consumer financing proposals for the Alaska gas project, some indirect, but all very strong, are applied to syngas and LNG imports on a broad scale.

The consequence of these measures broadly applied would be ruinous to our acquiring sounder energy technology in the future and could cripple the economy.

Thank you.

[The prepared statement of Mr. Wolf follows:]

STATEMENT OF SIDNEY M. WOLF, ASSISTANT PROFESSOR, DIVISION OF PUBLIC AND ENVIRONMENTAL AFFAIRS PROGRAM, INDIANA UNIVERSITY AT SOUTH BEND, IND.

I thank the Committee for the opportunity to make a statement on this very important energy, environmental, and let us not forget, consumer issue. Since the passage of the Alaska Natural Gas Transportation Act of 1976. The Environmental Policy Center has been deeply concerned with the repercussions of this project on the gas consumer. Contrary to the assumptions of many, notably the White House and Alcan, this project is not necessarily in the best interest of the gas consumer. In fact, under the pricing and tariff measures advocated by Alcan and the White House the Alaska gas project will likely bring down grevious harm upon the gas consumer, the national economy, and our prospects for sound national energy development in the future.

The litmus test of the economic merit of virtually all prospective business ventures is whether sufficient financing from private lenders can be obtained. Reluctance to invest on the part of private lenders implies a venture seeking investment faces serious risks jeopardizing investment. This is the case with the Alaska gas project. Excessive cost overruns, premature project abandonment after completion, and prolonged service interruptions are very real risks for the Alaska gas project, at least to the critical minds of investors. In order to attract sufficient private financing to the project, these risks must be either eliminated, substantially reduced or transferred in great part to parties other than the investors. Alcan and the White House choose to resort to risk transfer to entice hesitant private financing to the project it could not otherwise acquire.

Based on the view that the gas field owners, the State of Alaska and consumers will benefit from the project, various measures for their substantial sharing of the risks of the project are proposed. Before examining the specific methods of consumer risk-sharing in the project, let's scrutinize the validity of the contention that the project is beneficial to the gas consumer, for this contention is extended as the principal justification for consumer risk-sharing.

The price paid by the gas consumer for Alaska gas will determine whether the gas consumer is harmed or benefited by this project. If the price is such that the gas is economic, as is believed by the White House, then Alaska gas will no doubt be of great benefit to the gas consumer and the national economy. By economic, it is meant that the Alaska gas price is competitive with alternative energy supplies, and into the near future that would principally be fuel oil and electricity. The principal determinants of whether Alaska gas can be delivered at a competitive price will be its wellhead price and the capital costs of its transportation system.

Alaska gas will be the most expensive large supply of domestic natural gas ever offered for purchase to the American consumer due to the fact the Alcan project delivering it costs $6.7 billion, making Alcan the second most expensive construction project in history (behind the Trans-Alaska oil pipeline). The gas delivered by this project would be competitive if Alcan does not experience excessive overruns and the wellhead price does not substantially exceed the NEP $1.45 per mcf field price recommended by the White House. In reaching the conclusion that the delivered price of Alaska gas would be economic, the White House assumed NEP wellhead pricing and no future deregulation pushing the wellhead price of Alaska gas beyond the NEP formula, and further assumed the project would not suffer overruns exceeding 100 percent but could expect overruns of 40 percent. These assumptions float on quicksand. A forty percent overrun case is ridiculous and even a one hundred percent overrun case a highly optimistic underestimate. The only experience we have had with large-scale pipeline construction in arctic and sub-arctic environments is the Trans-Alaska oil pipeline and it suffered a phenomenal 800 percent overrun to $7.7 billion from an original estimate of $900 million. I do not expect an 800% overrun for the Alcan project principally because of its extensive use of existing developed road and pipeline rights-of-way. But all large-scale construction projects are afflicted with extensive overruns and the rule is the bigger and more exotic the project the larger the magnitude of the overrun.

The Superdome, built in the benign and balmy climate of New Orleans, overran 300 percent. Can we expect much less for 2,700 miles of custom-engineered pipeline and associated facilities traversing vast expanses of Alaska and Canada and built by tens of thousands of workers and large pieces of equipment in the most problematic climate and land environment on earth? At least a 200 percent overrun for the Alcan project is a virtual certainly in my estimation.

The White House Report to Congress concluded that even at what they deemed to be the "worst case" of cost overrun of 100 percent that Alaska gas would be marginally economic and produce a net national economic benefit, albeit a small one. A 200 percent overrun would balloon the capital costs of the Alcan project to $2.40 per mmbtu from Alcan's FPC filed cost of 80¢ per mmbtu. Assuming a NEP field price of $1.45 and a processing cost of at most 30¢ per mmbtu, which is what the White House Report did, the wholesale or "city gate" price of 200 percent overrun Alaska gas would be an astounding and wholly uncompetitive $4.15 per mmbtu. This price is nearly three times that of current interstate gas price levels and roughly equivalent to $25.00 per barrel OPEC crude (the current price of imported oil is around $13.00 per barrel). $4.15 gas is not even competitive with the minimum costs of highly costly nonconventional gas supplies such as LNG imports and coal gas, respectively $3.25 and $3.75 per mmbtu. The stratospheric price of 200 percent overrun Alaska gas would be boosted further into the unreachable heavens if complete field price deregulation becomes a reality during the 20-year life of the project.

Obviously, the private investment community would not finance the Alcan project if it delivered $4.15 gas unless Alaska gas is assured of sale by administrative action or legislation no matter what its price. Such an action would in effect shift the burden of overruns from debt financiers to gas purchasers and would thereby entice financing. It would be grossly hypocritical to recommend any measure with the knowledge that it compels the purchase of Alaska gas no matter what its price while at the same time claiming Alaska gas will not suffer dehabilitating overruns and will be voluntarily purchased by gas consumers. And yet this is what the White House report does in recommending as absolutely necessary rolled-in pricing for the sale of Alaska gas to residential gas consumers, for rolled-in pricing in effect forces gas consumers to purchase the gas no matter how much it costs.

Currently, the costs of all natural gas supplies, regardless of source, are averaged together and passed onto gas consumers at a single rate. This is called rolled-in pricing because new expensive supplies like Alaska gas are "rolled into" less expensive, older gas supplies. The White House recommends allocating the true high cost of Alaska gas to industrial gas consumers who can better afford the cost of conversion to other fuels. This is called incremental pricing, a form of marginal cost pricing. For the remaining overwhelming majority of residential gas consumers Alcan and the White House contend rolled in pricing is required.

Rolled-in pricing absolutely assures the sale of Alaska gas even at the theoretically unmarketable price of $4.15 per mmbtu. Because it averages gas costs, rolled-in pricing compels the gas consumer who is serviced by a gas supplier receiving Alaska gas to pay for the gas even if he does not want it or actually use it. This pricing method is blatant economic totalitarianism. Unlike rolled-in pricing, marginal cost pricing gives the gas consumer the choice to buy or not buy new, higher cost gas supplies added to his supplier's gas stores. Even without substantial cost overruns to the Alcan project, under marginal cost pricing many gas consumers would reject altogether or sharply reduce their consumption of costly Alaska gas. As marginally cost priced Alaska gas becomes progressively more expensive due to overruns more rejected or curtailed purchases would occur. Virtually every residential gas consumer would refuse 200 percent overrun Alaska gas if it is marginally cost priced, which is why Alcan demands rolled-in pricing.

The presence of rolled-in pricing makes false White House and Alcan's statements that the Alaska gas project will only be financed privately and not involve public financing. They apparently have a uniquely broad view of what constitutes private financing, for it includes the financial participation of the 40 million gas consumers in this country. In assuring the purchase of Alaska gas, rolled-in pricing functions indirectly, but almost as strongly as most direct means, as a consumer guarantee of project investment, since the forced sale of the gas enables the project sponsors to recover equity and pay back debt charges.

So many of us are awed by the capital costs of the Alcan project, which without overruns is an impressive $6.7 billion. But we should be flabbergasted by the more than $80 billion in consumer purchases of Alaska gas devoured by rolled-in pricing over a twenty year period for a 200 percent overrun system. $80 billion for the purchase of gas which would not otherwise be bought means that other sectors of the economy would to their detriment be deprived of $80 billion of consumer purchases and investment over the twenty-year life of the project. While other parts of the economy suffer from the loss of scores of billions, the corporate beneficiaries of Alaska gas revenues will be buried in profits. In response to questioning by the joint House Interior Indian Affairs and Public Lands and House Commerce Energy subcommittees several weeks ago, Northwest Pipeline President John McMillian claimed his company would stand to gain $200–$300 million in profits from the project and the gas field owners (principally Exxon, Atlantic Richfield, and Standard Oil of Ohio), collectively, $1–2 billion in profits. This is called income redistribution, but it appears to be running headlong in the wrong direction.

The capital requirements of the Alcan project are staggering, approximately $13.6 billion if the project suffers from the White House projected overrun of 32 percent. Astoundingly, this amount for a single gas transportation project is one-half the value of the assets of the entire gas transmission industry held at the end of 1976. Industry assets would be surpassed by the $30 billion capital demands of a 200-percent overrun project. It is patently obvious that the capital structure would be distorted by Alcan's huge appetite for capital, with or without overruns. This distortion, or more descriptively, this contortion of the capital structure grows progressively more harmful as cost overruns increase.

We can expect the exertion of upward pressures on interest rates, though to what extent is greatly dependent upon the magnitude of cost overruns and forced consumer gas purchases. Rising interest rates could dampen economic activity in other critical and already weak sectors of the economy such as the housing industry, which is extremely sensitive to interest rates. The Administration has made no effort to examine the relative gains and losses to various sectors of the economy due to the rise of interest rates induced by the Alcan project, particularly in high overrun cases. Tradeoffs are going to be made across various sectors of the economy, but apparently no one cares enough to determine who loses, although we certainly know that Exxon, Atlantic Richfield, Standard Oil of Ohio, and Northwest Energy will gain immensely.

Even more importantly than the difficult to measure rise in interest rates caused by the Alcan project is the diversion of massive amounts of capital from other sectors of the economy. Nowhere are the deliterious effects of massive capital shifting due to the building of an uneconomic Alcan project greater than in the area of energy development.

Capital, like fossil fuels, is a limited resource subject to vigorous competition for its use. This is particularly true for the wide variety of competing energy technologies available to us now and in the future, some of which are less costly and sounder than others. When the federal government contemplates artificially creating an extremely attractive opportunity for massive investment in one form of energy development, common sense tells us to compare the gains and losses produced by the favored form of energy development with those of alternatives not so favored. The billions invested either in the building of the Alaska gas project, with or without huge overruns, or in the purchase of its gas would if instead invested in an array of other conservation and domestic production alternatives produce not only more energy, but also more secure and environmentally desirable forms of energy with longer term benefits than 20 years of Alaska gas. I am speaking of investment in Devonian shale; deeper, tighter gas formations in existing producing regions; residential solar heating; home and commercial insulation retrofitting, industrial energy efficiency standards, and many other energy creating and saving actions.

Not only are these wiser alternatives denied the same highly advantageous government created artificial opportunity for attracting huge amounts of private financing and for coerced consumer purchases, but from another and more significant vantage point, commercial bank and consumer investment which they might otherwise freely receive is diverted away from them. This is a classic case of government advantaging large-scale, centralized, and major energy company ventures over smaller, more diversified, more competitive, and less costly and equally productive energy technologies.

Exhorbitantly priced Alaska gas forced down the throats of gas customers through rolled-in pricing will blast away the chief obstacle to massive LNG import and coal gas projects, and that is price competitiveness. For those favoring these technologies, Alaska gas at excessive cost and cost averaged with conventional gas supplies will be one giant step toward placing gas prices in general closer to the higher levels needed to make coal gas and LNG imports competitive. We must keep in mind that the 20 tcf of Alaska gas will supply 5 percent of our gas needs for the next twenty years, a proportion hundreds of times greater than any other single source of domestic gas. As the largest source of domestic gas, it cannot help but influence overall gas prices when cost-averaged with other gas supplies.

High cost Alaska gas will also contribute to gas price "chasing" should deregulation become a reality. In a situation of deregulation and great market demand for gas, the price of lower cost gas supplies would tend to run a step behind the price of large volumes of higher cost gas supplies even though the actual cost gap between the two is much greater than the price gap. In other words, deregulated low cost gas benefits greatly in terms of price in the company of higher priced but still marketable gas. Thus, the presence of Alaska gas and other costly gas supplies such as LNG imports and coal gas which are made de facto marketable by rolled-in pricing will procreate windfall profits for low cost gas supplies in an atmosphere of deregulation. Without an excess profits tax or other compensatory measures, we arrive at a situation where the pockets of gas interests are transformed into money bags and those of gas consumers and the public in general into air holders.

Deregulation and rolled-in pricing are polar opposites philosophically. Hypocritical gas industry insistence on both greatly profits them while grossly harming the gas consumer. This is especially the case for Alaska gas. We cannot free the gas industry from the coercion of price controls and then shackle the gas consumer with forced purchases of huge volumes of Alaska gas. This is highly unjust.

The final insult to the gas consumer is that the forced purchase of Alaska gas ironically exposes this gas supply to the very same disastrous behavior compelling us to seek Alaska gas in the first place—wasteful consumption.

Rolled-in pricing encourages excessive gas demand and not gas conservation. This effect, tragic whether Alaskan gas is attractively or exorbitantly priced, is principally caused by the incorrect price signal rolled-in pricing gives the gas consumer. By averaging its higher cost with the lower cost of old gas, rolled-in pricing makes the Alaska gas appear cheaper and hides its true cost. With its cost hidden the gas consumer does not feel the need to use the new gas as frugally as he would in the case where he is straightforwardly charged for its true high cost, as is the case with marginal cost pricing. In addition, frugal gas purchasers are penalized by rolled-in pricing. Whether or not they use the new increment of their gas supply attributable to Alaska gas because of cost averaging they pay for it anyway with the added penalty of paying more for the lower cost gas they actually use.

Compounding the injury to the gas consumer, economy, and future energy development, the White House and Alcan recommend two other strong forms of project risk transfer to the consumer for the sole purpose of attracting private financing to the project it probably would not otherwise receive. One is a form of direct consumer debt guarantee whereby gas consumers would maintain debt service in the event of prolonged service interruption, and possibly, premature project abandonment after completion. The other is a high minimum rate of return on equity after taxes to which Alcan would be entitled no matter how catastrophic overruns become.

The advocacy of explicit measures to protect debt investment in the event of the prolonged service interruptions and premature project abandonment tacitly admits these contingencies are very probable, whereas insistence on no such measures indicates sureness that these contingencies are remote. The White House, Alcan, and the FPC contradict themselves in proposing consumer debt servicing in the event of prolonged service interruption or premature project abandonment while also claiming these events are at most only slight possibilities. The recent breakdowns of the Trans-Alaska oil pipeline, mentioned previously as the only real experience we have with monumental pipeline systems in the far North, tells us that prolonged service interruptions are inevitable. The explosion of Pump Station #8 just weeks after the system was turned on has curtailed significantly delivery of Prudhoe oil for the next few months. No one can hope for quick repair of a broken pipeline buried deep in frozen tundra in the all-night, —50° F. or worse winters of Alaska and the Yukon, leaving gas consumers to pay Alcan's debt charges while the gas ballyhooed as saving them from winter gas shortages is not forthcoming. Call this the freeze and pay plan, if you like.

The White House Report adopts the variable rate of return proposal put forward earlier by the FPC. Under the variable rate of return proposal return on equity would decrease from a maximum level as project costs exceed a project budget fixed by the federal government. However, the proposed rate of return would not be completely tied to cost performance for the decrease would stop at a minimum level of return and not be allowed to reach the no return level. Tying the rate of return to cost performance is intended as an incentive to control overruns on the project sponsors' part, for the lower the overrun, the higher the rate of return.

However, effectiveness of the variable rate of return as a check on overruns depends on its lower limit. The variable rate of return is most effective when it is allowed to drop to zero and becomes progressively less effective as it moves away from the null return. When the minimum allowed rate of return is comparable to the return customarily obtained by project sponsors then it is of dubious value as a weapon against overruns.

The White House recommends leaving the calculation and implementation of the variable rate of return to the FPC and the Canadian NEB. That would be a mistake if the FPC sticks to its previous formula for the variable rate of return. The FPC proposed an 18 percent maximum and 11 percent minimum allowed rates of return. An 18 percent maximum allowed rate of return considerably exceeds the 11.8 percent rate of return averaged by the integrated energy industry over the past ten years (1963–73). When compared with the industry average, a minimum allowed rate of return of 11 percent seems quite comfortable and is in fact the average rate of return of the companies involved in the Alcan proposal. A minimum return equal to the sponsors present return is a weak barrier to intense overrun pressures. The project sponsors might very well resign themselves to enduring their usual healthy 11 percent rate of return if they conclude overruns are too difficult, wearing, or just plain impossible to manage effectively. Their submitting to overruns with a high minimum rate of return is even more likely if the gas is assured of sale through rolled-in pricing and their debts are backstopped by consumers in the events of service interruptions or project abandonment. Only when profits are severely penalized for cost overruns by sharply reducing or eliminating altogether the minimum rate of return can we be absolutely certain project sponsors will work themselves silly to hold down project costs. It should be added that a high allowed minimum rate of return is, like rolled-in pricing, an indirect but strong form of consumer guarantee for project financing since the lenders are assured that the project sponsors will garner a return ample enough to go a long way in meeting debt charges.

I close this statement with my greatest fear about the transfer of the investment risks of the Alcan project from the major banks to millions of gas consumers such as myself. I fear the precedent consumer financing for the Alcan project would set. Rolled-in pricing and high minimum allowed rates of returns are commonly used for new gas projects and have for years received considerable criticism from consumer interests who have been harmed by them. But never before have consumer risk transfers been used on such a mammoth seale for an energy project, or any other kind of private development project for that matter. Though the most profitable large industry in the U.S., the energy industry has become increasingly less willing to invest their huge capital resources in energy development and have long pressured government regulators to require consumers to play a lead role in financing and bearing the financial risks of major energy projects. Apparently, the energy industry is succeeding. The FPC recently denied a petition by the State of California to limit the charges that gas utilities could bill their customers in advance for building coal gasification plants, which cost $800 million and $1.2 billion and are of dubious technological and economic feasibility. Once the capital voracious energy industry is given a healthy helping of consumer financing for massive and costly energy development projects like the Alcan project, their appetite for more for other projects will become insatiable. The very existence of consumer financial involvement in an enormous energy project like Alcan could reduce the future willingness of the energy industry to initiate major projects unless consumers are required to participate in risk-sharing and pay for the energy product no matter how steep the price.

Around the corner looms the prospect of the federal government strong-arming consumers over and over again to financially assist the already profitable and pampered energy industry. The Alcan project is the beginning of a new era of energy financing, where the consumer bears the investment risks of costly energy technologies whose presence prejudices the development of less costly and environmentally and economically sounder alternatives at the same time major energy companies shed investment responsibility almost completely but not their control over energy profits and the determination of the character of future energy development.

Finally, for what it is worth, massive coerced consumer financing and risk-sharing are antithetical to the cardinal principle of free enterprise. And that is, private entrepreneurs and financiers must fully assume the initial risks of investment in a venture they back, with the consumer playing the exclusive role of returning invested capital only if the venture fulfills a need or a demand. Can anyone tell me what consumer need or demand a runaway overrun Alcan project fulfills?

Senator BARTLETT. Thank you, Mr. Wolf.

Senator Jackson?

The CHAIRMAN. I don't have any questions.

Senator BARTLETT. Senator Stevens?

Senator STEVENS. No. Thank you. We appreciate your testimony.

Senator BARTLETT. Mr. Wolf, we have no questions. We thank you very much for your testimony.

Senator BARTLETT. Barbara Graham, attorney, representing the Sierra Club, Wilderness Society, National Audubon Society, and the Alaska Conservation Society.

Welcome, Ms. Graham. We are happy to have you.

If you could summarize your statement, we would appreciate it and the entire statement will be placed in the record.

Ms. GRAHAM. I will, Senator.

Senator BARTLETT. You may proceed however you wish.

STATEMENT OF BARBARA GRAHAM, ATTORNEY, REPRESENTING THE SIERRA CLUB, WILDERNESS SOCIETY, NATIONAL AUDUBON SOCIETY, AND ALASKA CONSERVATION SOCIETY

Ms. GRAHAM. My name is Barbara Graham. I represent the Sierra Club, the Wilderness Society, the National Audubon Society and the Alaska Conservation Society. I am also authorized to state that I am speaking for the Environmental Policy Center today.

I would like to summarize portions of my statement today in the interest of time. We have been in this case for some years and the position of the conservation groups has been stated many times.

Our position is that the vast pipeline that has been chosen by the President, or the Alcan project, presents the most rational approach of the available alternatives and is likely to be least harmful to the environment if it is properly constructed.

On the whole, Alcan offers the best available solution if a pipeline is to be built. The decision on whether any pipeline is to be built at all is fundamentally acknowledged, although the environmental costs and benefits must be part of the equation.

Thus, we approve of the President's decision which would require the private financing of this project for if it can attract private investors, that would be a much more reliable indicator than a government decision would be that it makes economic sense.

We have long supported serious consideration of Alcan route along the Fairbanks corridor and we see selection of this route as the validation of the process. For the environmental impact statement forced this route out into the arena as an alternative to the original Artic gas project.

Of course, some problems remain with the Alcan project as no large construction job could be perfect. The Northwest Pipeline Company and Alcan management are making a sincere effort to design this project so as to minimize disturbance to natural values and they have provided comments from many outside interests.

However, there are many site specific studies which must still be done to pick the exact pipeline route. Sensitive areas, such as marshes, or the habitats of rare or easily disturbed species, must be identified for the route changes of special construction techniques. And in Canada many such problems must be dealt with since a large portion of the pipeline would diverge from highway or other borders and several recreation areas would be crossed or skirted.

But we understand that further discussions would be held between the applicants and residents and conservation groups in the affected areas to work out a suitable route.

In addition, there are several specific problems with routing with regard to the Northern border section along Montana, the Dakotas, Minnesota, Iowa and into Illinois. We feel that a route passing farther north and east in North Dakota would avoid many of these problems.

We are particularly concerned about the crossings of several scenic rivers and the prairie pothole region in the Dakotas, which is a crucial waterfowl breeding area. But even some minor route changes could reduce damage to this region.

We will be working with representatives of the Northern Border Pipeline Co. and we hope that many of the conflicts over these areas can be resolved.

But the crux of this case now for us is the implementation of the project. We view the congressional role now and in the future as more active than simply approving the President's decision.

First, the Senate has the responsibility to scrutinize the President's nomination of a Federal inspector. This must entail exacting assurances from the nominee that the inspector's authority will be fully utilized in requiring proper engineering design, and environmental protection measures, a fully adequate quality control program, an education program for all employees and tight scheduling and cost control.

The Federal inspector must pledge that he would require full compliance with the terms and conditions imposed by the President's decision, and those imposed by the relevant Federal agencies and the State of Alaska.

He must also pledge that environmental stipulations and terms and conditions will be vigorously enforced, and that these requirements will be given equal emphasis with engineering matters in both the design and construction phases of the project.

The Senate must be prepared to follow the official actions of the Federal inspector and if necessary to consider a reprimand or his removal. The impotence, the lack of central responsibility, and the blame passing that occurred during construction of the Alyeska project cannot be permitted to recur.

Second, we believe that it is appropriate for the committee to describe in fairly specific terms, in the report accompanying the Senate's approval resolution, how it expects the Executive to proceed in planning, monitoring, and enforcing the terms and conditions to be imposed upon the builders of the pipeline.

Therefore, we suggest here for your consideration some measures which we believe would contribute to a more successful construction project than the Alyeska oil pipeline proved to be.

First, this committee must make it very clear that the Federal inspector will be held responsible for all phases of monitoring and enforcing this construction project.

If the actual issuing of permits must come through each individual responsible agency, the inspector must nevertheless tightly coordinate the standards and terms and conditions to be imposed in each permit. Conflicts here will only engender confusion later on.

And it is crucial that the Federal inspector have the authority to enforce the stipulations, terms and conditions. There must be a single responsible figure for the project builders to respond to. And the Federal inspector must be accountable for failure of enforcement.

The committee must make it clear that it expects the Federal inspector to order or require enforcement actions when that is needed. And if this will require additional statutory authority for the Federal inspector, through a reorganization plan, as was suggested in the Presidential decision, the Congress must address this expeditiously. For if this project is to be under any better control than Alyeska was, the Federal inspector must be fully accountable.

Two. It is crucial that there be a balance between the engineering and environmental staffs of the Federal inspector, during both project design and construction. The staff must be equal in authority between environmental and engineering people and access to the decisionmaker, not just equal in number.

We cannot accept a repeat of the Alyeska situation in which the biologists were merely advisers, and only the engineers had authority to issue and enforce notices to proceed.

It is our expectation that proper construction techniques are no more expensive than sloppy damaging ones and they may, indeed, be cheaper. And delays are not needed in order to take precautions for the benefit of fish and wildlife if the planners have sufficient data beforehand to plan to schedule each procedure when it will cause the least damage.

The key is to build the proper measures into the plan from the beginning. And for this to occur, the environmental experts must have an equal voice in the planning process, as well as later during construction.

Three. One of the most important functions of the Federal inspector must be to tightly coordinate the actions and objectives of the authorized officers of the relevant agencies. The authorized officers must not only know what each of the others is doing, but also work together to avoid conflicting requirements.

Furthermore, interdisciplinary reviews by this group, of various permits and conditions to be imposed by each of them, go a long way toward the required balance between environmental protection and engineering efficiency.

Four. One lesson of the Alyeska experience is that the quality control program of the pipeline builders must be fully acceptable and in operation before construction begins. On the Alyeska project, that program was inadequate or unready for the whole first year.

Thus, the Federal-State monitoring staff was forced to attempt to perform part of the quality control for the whole line. This required many more inspectors than were available, and the inevitable result was that quality control was almost nonexistent.

Five. Another Alyeska lesson is that the environmental monitors must have clear authority to continue in operation through cleanup and revegetation stages of the project. Uncertainty surrounding JFWAT's continuing existence is currently hampering its efforts in prodding the last stages of cleanup and mitigation of damage on the Alyeska line.

The biological teams must begin work immediately, surveying streams for appropriate crossings, and marking sensitive habitat to be avoided. Unless adequate data is available so the route and construction plans can be properly designed beforehand, the conflicts, inefficient late changes, and unnecessary damage that occurred on Alyeska will be repeated.

Finally, in one of the most important changes from the Alyeska project, we believe there must be an independent citizen's council to oversee and advise the Federal Inspector on the environmental, social, and economic aspects of the project in Alaska.

We would suggest that the council consist of five members. Two should be Alaskan Natives, one representing the North Slope Borough and one representing Doyon, both of whose lands will be affected; two members should be selected by interested environmental groups, and one by a group such as the Alaska League of Women Voters.

A set of several candidates nominated by these groups would be put before the Federal Inspector and the Executive Policy Board for ultimate selection.

The council must have a professional staff consisting of perhaps one engineer and one environmental specialist, and a coordinator, who should have either a managerial or legal background. The council should have its headquarters in Alaska.

Such a council and its staff must have access to all relevant Federal and State documents and reports during project planning and construction design, and guaranteed independent and unannounced access to the project, including use of runways by private airplane, if necessary, during all phases of construction.

This access will preclude the hostility and misunderstanding that occurred during construction of the Alyeska line. And it will also reduce the possibility of public frustration that might lead to litigation over enforcement or other aspects of the project. Our objective is that the council participate constructively in the implementation of the project, not hold it up.

With the above assurances of access, the council could be funded by the project builders if that is otherwise appropriate.

It is important that this council and its staff be involved in planning from the beginning, so that public views can be efficiently channeled into the very heart of the project. This will reduce the possibility of friction later on.

We believe that the Alcan management would not only accept but endorse these ideas, as formalizing the type of cooperation that they hope to realize in any event. We believe they agree with us that such measures can only improve the project. We hope that you agree as well.

Thank you very much.

[The prepared statement of Ms. Graham follows:]

STATEMENT OF BARBARA GRAHAM, ATTORNEY, REPRESENTING THE SIERRA CLUB, WILDERNESS SOCIETY, NATIONAL AUDUBON SOCIETY, AND ALASKA CONSERVATION SOCIETY

BACKGROUND

The conservation groups represented here today have been active in this case for a long time, both before the Federal Power Commission and many of the Federal agencies that were considering this matter pursuant to the Alaska Natural Gas Transportation Act. We come before you today because we hope to fill a valuable continuing role as the project is implemented. And the Senate, too, will have a continuing role here, particularly in approval of the nomination of the Federal Inspector.

Our aim since we began working on this case in January, 1974 has been two-fold. Range, because it is the last opportunity to preserve a stretch of United States National Wildlife Range in Alaska and the ecologically connected North Slope of the Yukon. These areas were threatened by the first applicant in this case, the Arctic Gas project. We have long sought Wilderness status for the Arctic Wildlife Range, because it is the last opporunity to preserve a stretch of United States arctic coastal plain from hydrocarbon development, and it is the only place in this Nation where an unbroken sweep of land forms, from mountains and foothills to broad coastal plain and the sea, can be preserved. Its scenic grandeur and scientific value are beyond measure. The Range is also important because its large size permits it to be a self-sustaining ecosystem in the arctic, where vegetation grows slowly and vast acreages are required to support viable wildlife populations.

Because the Arctic Gas proposal has since dropped out of the competition, this Nation now has a clear opportunity to protect this unique area as a Wilderness. In fact, in his Report of the Mackenzie Valley Pipeline Inquiry, Justice Thomas Berger suggested an agreement on this issue between the United States and Canada: he said the U.S. should agree to grant Wilderness status to the Range, and Canada would afford similar protection to both the North Slope of the Yukon, in order to fully protect the great international Porcupine caribou herd, and a white whale sanctuary off the Yukon North Slope. We believe such an agreement should be pursued.

But we had, and still have, a second goal here, and that is to promote sensible land use planning in Alaska. Alaska is our last chance to learn to plan for development instead of letting it just happen. It is very important that undisturbed territory be invaded only where absolutely necessary, so that a balance may be achieved between resource development and preservation of the great reservoir of wilderness that the State contains. For any remaining wilderness will be of inestimable value long after the hydrocarbons and minerals are gone and the pipelines are empty. Thus we have always believed that if a gas pipeline must be built, the route chosen should be the one which causes the least possible damage to the renewable resourses of the State of Alaska, and which uses existing utility and transportation routes, so that it does not invade Alaska's large but fast diminishing reserves of wilderness.

Therefore, we advocated from the beginnning serious consideration of a pipeline route along the TransAlaska oil pipeline through Fairbanks, and from there following the Alcan highway and existing pipeline corridors in Canada.

In a classic and heartening example of the way NEPA should work, the Staff of the Federal Power Commission studied this route and concluded in the environmental impact statements that such a route was environmentally preferable to the two projects already applied for and several alternatives. As a result, an industry group came forward to file an application for the Fairbanks route, and that was the birth of the Alcan project. This is the route that is now before you as the President's selection.

POSITION OF THE CONSERVATION GROUPS

Our position on this gas pipeline decision has been stated many times: if a pipeline is to be built, the Alcan project presents the most rational approach of the available alternatives, and it is likely to be the least harmful to the environment if properly constructed. This is not to say that there are no problems with the Alcan project. There are some, and they will be discussed below. But on the whole Alcan offers the best available solution if a pipeline is to be built.

The decision on whether any pipeline should be built at all is a fundamentally economic one, although environmental costs and benefits must be part of the equation. We approve of the portion of the President's decision which would require private financing of this project. For if it can attract private investors, that will be a much more reliable indicator than a government decision would be that it makes economic sense.

REMAINING PROBLEMS WITH THE ALCAN PROJECT

The Northwest Pipeline and Alcan management are making a sincere effort to design this project so as to minimize damage to natural values and undisturbed territory in Alaska and they have invited comments from many outside interests.

But since the proposal is still relatively new, much scientific and engineering work must be done to ensure that this ideal can be accomplished. Even the pipeline route itself cannot be fixed in detail until walking surveys have been carried out, including identification of sensitive areas, such as marshes, habitat of rare or easily disturbed species, and areas with high present or potential recreational values. Since the preliminary routing was selected without this information, many changes will be needed, including in some areas, re-positioning of compressor sites or work camps.

In Canada, many such problems must be dealt with, since a large portion of the pipeline will diverge from the highway or other corridors, and several important recreation areas would be crossed or skirted. We understand that further discussions will be held between the applicants and residents and conservation groups in affected areas, to work out a suitable route. We would hope and expect that the project sponsors will continue their efforts to accommodate the concerns of people who will be affected by this pipeline, as well as the needs of fish and wildlife populations, which are so important to the character and economy of these regions.

We want to emphasize what many involved in this project already know—that site specific studies to determine precise routing, design, scheduling, construction techniques and mitigation measures, must begin as soon as possible. For only with good data can this pipeline be built the way we hope it will. Thus this next year will be the critical time for gathering the information upon which the construction techniques and plans will depend.

Several specific problems with routing exist with regard to the Northern Border section of the route reaching across Montana, the Dakotas, Minnesota, Iowa and into Illinois. But a route passing farther north and east in North Dakota would avoid many of them. We are particularly concerned about the crossings of several scenic rivers and the prairie pothole region in the Dakotas, which is a crucial waterfowl breeding area. But even some minor route changes could reduce damage to this region. We will be working with representatives of Northern Border, and hope that many of the conflicts over these areas can be resolved.

In general, construction of any project of this size will disrupt and destroy land, habitat, water courses and wildlife, and will have a more or less temporary negative impact on the towns and villages which must absorb the great influx of workers, machinery, traffic and noise. Our hope is, however, that because of good intentions on all sides, every effort will be made to plan and carry out this project with as little disruption and lasting damage as possible.

IMPLEMENTATION OF THE PROJECT UNDER THE ALASKA NATURAL GAS TRANSPORTATION ACT

We view the Congressional role now and in the future as more active than simply approving the President's decision. First, the Senate has the responsibility to scrutinize the President's nomination of a Federal Inspector. This must entail exacting assurances from the nominee that the Inspector's authority will be fully utilized in requiring proper engineering design, and environmental protection measures, a fully adequate quality control program, an education program for all employees, and tight scheduling and cost control, by the project sponsors. The Federal Inspector must pledge that he will require full compliance with the terms and conditions imposed by the President's decision, and those imposed by the relevant federal agencies and the State of Alaska. He must also pledge that environmental stipulations and terms and conditions will be vigorously enforced, and that these requirements will be given equal empasis with engineering matters in both the design and construction phases of the project.

The Senate must be prepared to follow the official actions of the Federal Inspector and if necessary to consider a reprimand or his removal. The impotence, the lack of central responsibility and the blame passing that occurred during construction of the Alyeska project cannot be permitted to recur.

Second, we believe that it is appropriate for the Committee to describe in fairly specific terms, in the Report accompanying the Senate's approval resolution, how it expects the Executive to proceed in planning, monitoring and enforcing the terms and conditions to be imposed upon the builders of the pipeline. Therefore, we suggest here for your consideration some measures which we believe would contribute to a more successful construction project than the Alyeska oil pipeline proved to be.

(1) The President's decision leaves somewhat unclear the exact line of authority for a) the issuance of permits, stipulations, and site specific terms and conditions, b) monitoring of their compliance, and c) enforcement.

As we interpret the document, the authorized officers of the various federal agencies are to retain individual responsibility for issuing the rights of way permits or other approvals under their statutory jurisdiction and also for including their own site specific terms and conditions in the permits. And while the Federal Inspector is clearly authorized to coordinate the monitoring phase (Decision, p. 41), the President still must seek authority "to transfer to the Federal Inspector supervisory authority over enforcement of terms and conditions." (Decision, p. 42).

In other words, the authority to set the standards of performance for this construction project may be scattered among several agencies with different or conflicting requirements, and the enforcement power may or may not be centralized in the Federal Inspector.

This is a formula for confusion, and may breed some of the very problems that occurred on the Alyeska project that everyone is trying to avoid this time.

This Committee must make it very clear that the Federal Inspector will be held responsible for all phases of monitoring and enforcement of this construction project. If the actual issuance of permits must come through each individual responsible agency, the Inspector must nevertheless tightly coordinate the standards and conditions to be imposed in each permit. Conflicts here will only engender confusion later on.

And it is crucial that the Federal Inspector have the authority to enforce the stipulations, terms and conditions. There must be a single responsible figure for the project builders to respond to. He must also be accountable for failure of enforcement. Thus while the President's decision would allow the Federal Inspector to overrule an enforcement action by an agency Authorized Officer (Decision, p. 42), the Committee must make it clear that it also expects the Federal Inspector to order or require enforcement actions when that is needed. If this will require additional statutory authority for the Federal Inspector, through a reorganization plan, the Congress must address this expeditiously. For if this project is to be under any better control than Alyeska was, the Federal Inspector must be fully accountable.

(2) It is crucial that there be a balance between the engineering and environmental staffs of the Federal Inspector, during both project design and construction. They must be equal in authority and access to the decision-maker, not just equal in number. We cannot accept a repeat of the Alyeska situation in which the biologists were merely advisors, and only the engineers had authority to issue and enforce notices to proceed.

Because biologists and engineers see the world through different eyes, both views must be equally represented to the decision maker. Otherwise, all the promises of environmental protection may be sacrificed for the sake of construction efficiency. Certainly the balance must not tip the other way either, for we must all concede that some wildlife, terrain and habitat damage is inevitable.

But it is our expectation that proper construction techniques are no more expensive than sloppy, damaging ones, and they may indeed be cheaper. And delays are not needed in order to take precautions for the benefit of fish and wildlife if the planners have sufficient data beforehand to plan to schedule each procedure when it will cause the least damage. The key is to build the proper measures into the plan from the beginning. And for this to occur, the environmental experts must have an equal voice in the planning process, as well as later during construction.

(3) Similarly, one of the most important functions of the Federal Inspector must be to tightly coordinate the actions and objectives of the Authorized Officers of the relevant agencies. The Authorized Officers must not only know what each of the others is doing, but also work together to avoid conflicting requirements. Furthermore, interdisciplinary review by this group, of the various permits and conditions to be imposed by each of them, would go a long way toward the required balance between environmental protection and engineering efficiency.

(4) One lesson of the Alyeska experience, is that the quality control program of the pipeline builders must be fully acceptable and in operation before construction begins. On the Alyeska project, that program was inadequate or unready for the whole first year. Thus, the Federal and State monitoring staff was forced to attempt the quality control of the whole line. This required many more inspectors than were available, and the inevitable result was that quality control was almost non-existent.

(5) Another Alyeska lesson is that the environmental monitors must have clear authority to continue in operation through cleanup and revegetation stages of the project. Uncertainty surrounding JFWAT's continuing existence is currently hampering its efforts in prodding the last stages of cleanup and mitigation of damage on the Alyeska line.

(6) The biological teams must begin work immediately, surveying streams for appropriate crossings, and marking sensitive habitat to be avoided. Unless adequate data is available so the route and construction plans can be properly designed beforehand, the conflicts, inefficient late changes and unnecessary damage that occurred on Alyeska will be repeated.

(7) Finally, in one of the most important changes from the Alyeska project, we believe there must be an independent citizen's council to oversee and advise the Federal Inspector on the environmental, social and economic aspects of the project in Alaska.

We would suggest that the council consist of five members. Two should be Alaskan Natives, one representing the North Slope Borough and one representing

Doyon, both of whose lands will be affected; two members should be selected by interested environmental groups, and one by a group such as the Alaska League of Women Voters. A set of several candidates nominated by these groups would be put before the Federal Inspector and the Executive Policy Board for ultimate selection.

The council must have a professional staff consisting of perhaps one engineer and one environmental specialist, and a coordinator, who should have either a managerial or legal background. The council should have its headquarters in Alaska.

Such a council and its staff must have access to all relevant federal and state documents and reports during project planning and construction design, and guaranteed independent and unannounced access to the project, including use of runways by private airplane, during all phases of construction. This access will preclude the hostility and misunderstanding that occurred during construction of the Alyeska line. And it will also reduce the possibility of public frustration that might lead to litigation over enforcement or other aspects of the project. Our objective is that the council participate constructively in the implementation of the project, not hold it up.

With the above assurances of access, the council could be funded by the project builders if that is otherwise appropriate.

It is important that this council and its staff be involved in planning from the beginning, so that public views can be efficiently channeled into the very heart of the project. This will reduce the possibility of friction later on.

We believe that the Alcan management would not only accept but endorse these ideas, as formalizing the type of cooperation that they hope to realize in any event. We believe they agree with us that such measures can only improve the project. We hope that you agree as well.

Senator BARTLETT. Thank you. Senator Jackson.

The CHAIRMAN. I want to simply say that we are very appreciative of Ms. Graham's statement. I would hope that if you run into any trouble in connection with the monitoring and other proposals that you have made with the Department of Energy, you will let us know.

I think you have made some very good suggestions. I gather the Secretary of Energy is interested in this proposal.

Ms. GRAHAM. Yes. I have made several of them, although not this entire list, to the Secretary through Mr. Goldman already. I think I will make a formal presentation of our list.

The CHAIRMAN. I hope you will let us know if you encounter any trouble there.

Ms. GRAHAM. Thank you, Senator.

Senator BARTLETT. Thank you, Chairman Jackson.

Senator Stevens?

Senator STEVENS. I, too, would welcome that counsel. I assume that you would agree that the State of Alaska through whose land this pipeline will go and perhaps the burrough in the Fairbanks area and members of the Department of the Interior ought to be on that council. I would welcome that council provided it had the balance of representation.

Ms. GRAHAM. That is very important. That is why I was trying to stress what I did. I would expect that the State will have other avenues of perhaps much more direct control, certainly over the right-of-way permit in terms of conditions there.

I would hope that the Federal Government and the State would be cooperating so that the State people would be actively involved in actually setting terms and conditions which may have much more direct power than this council may ever have.

So, too, for the Secretary of Interior. But I was assuming that none of the groups you represent have access to that kind of activity and this council has sort of an outside—would be the only way they would have that information about what was even going on.

Senator STEVENS. That is a good idea as far as I am concerned. I think the Alaska League of Women Voters and the North Slope people could be involved. That is a good suggestion.

But I think the State and the North Slope Burrough should also be involved.

Senator BARTLETT. Ms. Graham, thank you very much for your testimony.

Professor Doscher, professor of petroleum engineering from the University of Southern California in Los Angeles.

I am sorry you had to wait. You may proceed as you desire. You may read your statement in its entirety or summarize as you wish, but your entire statement will be placed in the record.

Dr. DOSCHER. I believe I will start out——

Senator BARTLETT. It is a very short statement.

STATEMENT OF DR. TODD M. DOSCHER, PROFESSOR OF PETROLEUM ENGINEERING, UNIVERSITY OF SOUTHERN CALIFORNIA, LOS ANGELES, CALIF.

Dr. DOSCHER. I believe I will start out with the statement. I believe I can read it expeditiously.

I should say that I was retained by the Department of Legislative Affairs for the State of Alaska several months ago to audit and review the plans for operating the Prudhoe Bay field as they were represented by the operators this past May.

As a result of that study, the report has been submitted to the State. It is not yet in its final draft. But I am informed that the substance of it may relate to you in this presentation.

There is a danger that a decision now to construct a pipeline to withdraw gas from the Prudhoe Bay Field will reduce the total amount of oil that may ultimately be recovered from the Sadlerochit Reservoir.

The stated conclusion of the operators of the field that the early withdrawal of gas will not affect the recovery of the crude oil is based on mathematical modelling of the reservoir and its performance.

Mathematical modelling is a powerful tool for analysis of reservoir performance, but the results of such modelling exercises are preordained by the values of certain parameters that are chosen to represent the performance of the reservoir. Unfortunately, it is only from the performance of the reservoir that the values of these critical parameters can be assigned with a high degree of confidence.

The stated conclusion of the operators that early gas withdrawals will not diminish oil recovery is in contradiction to the lore of reservoir engineering. This lore, substantiated by significant history and scientific observations, leads most reservoir engineers to call for complete pressure maintenance and no withdrawal of gas in the absence of natural water encroachment or an induced water flood.

The Sadlerochit reservoir is bigger than any other reservoir discovered in the United States, but the principles underlying the production of fluids therefrom are no different than those controlling fluid flow in smaller reservoirs. The much greater thickness of the Sadlerochit reservoir will however lead to greater recovery efficiency than would be anticipated from smaller reservoirs. This increase will result from gravity drainage supplementing the basic solution gas drive of the reservoir.

The operators have estimated that crude oil recovery will amount to 40 percent of the original oil in place even with concurrent early withdrawals of gas and without the implementation of a major water flood early in the life of the reservoir.

Such an unusually high recovery efficiency can be anticipated only by invoking the hypothesis that the expanding gas cap will reduce the oil saturation in the pores of the rock to very low values during the relatively short life of the Prudhoe Bay Field.

This hypothesis cannot be substantiated by the study of field case histories. The Prudhoe Bay Field will be produced at maximum crude oil rates for the order of only 7 to 10 years after which it will begin a precipitous decline.

A total economic life of perhaps 25 years is anticipated. This is a far shorter time period than the geological eras which permitted the almost complete segregation of oil and gas.

No one will know for at least 2 and perhaps 5 years from now how effective the expanding gas cap is in displacing crude oil, and therefore whether gas can be safely withdrawn from the reservoir without affecting the ultimate recovery of crude oil.

The operators themselves have implied that it is impossible to draw firm conclusions as to the need and extent of water flooding the Sadlerochit reservoir until reservoir performance is observed for several years. It is this very same logic that should be applied in reaching a conclusion as to the advisability of early gas withdrawal on reservoir performance.

It must be borne in mind that some one-third of our Nation's reserves of liquid fuels are in the Prudhoe Bay Field. No iota of this precious reserve should be jeopardized.

I must also call your attention to the fact that some 12 billion barrels of crude oil will be left behind in the Sadlerochit reservoir even given an optimistic outcome of the present plans for producing the reservoir. No significant planning or development studies to my knowledge are underway to seek means for recovering some of this residual crude oil.

I know of no method that can be stipulated at this time that will for certain achieve such enhanced recovery, but I do know that much research and development is underway on reservoirs of lesser stature. There is some indication that a reduction in reservoir pressure may work against the optimum utilization of tertiary recovery processes that are currently being studied.

I submit that this is still an additional valid reason for being wary of early gas withdrawal which leads to a reduction in reservoir pressure.

Let me now turn to a brief discussion of the significance of the Prudhoe Bay gas itself, and the decision as to whether or not to construct a pipeline at this time. Should the line be constructed at this time, at a cost that surely must exceed the $10 billion cost of the Aleyska oil line—surely because of its greater length and continuing inflation, and should it subsequently become clear that early gas withdrawal will reduce the recovery of crude oil, the Nation will then have a staggeringly expensive white elephant on its hands. It could only be paid out under such circumstances by sacrificing the recovery of desperately needed liquid fuels.

It is most important to consider whether, even if early gas withdrawal from the Prudhoe Bay Field were not to jeopardize ultimate oil recovery, the construction of the pipeline and the delivery of North Slope gas is in the best interest of the Nation at this time.

I submit that it is not.

At the very best, the delivery of gas from Prudhoe Bay will not attain a value of 1 trillion cubic feet a year—probably only three-fourths of a trillion. This amount is less than 5 percent of the amount of gas we now use in this country.

Moreover, it will not be delivered until 1983 at the earliest. It is difficult to believe that its delivered cost in today's dollars will be less than twice that which the President has recommended as the ceiling on new gas.

I sincerely believe that somewhat larger amounts of gas in the same time frame can be provided by allowing new and enhanced gas production to be sold at somewhat higher prices than now permitted by Federal regulations. Based on the studies of myself and my associates I do not believe that gas from tight and deeper reservoirs, from new exploration plays, from geopressured aquifers, eastern shales and Appalachian coal seams will ever be the bonanzas that some have reputed them to be.

But they will get us by for another decade or two if you permit them to be developed and sold at prices significantly less than what I believe would be the cost of Prudhoe Bay gas to the American people.

This increase in the cost of natural gas will not constitute a rip-off of the American people. We don't have cheap energy resources available to us and our resources of fluid energy sources are rapidly diminishing.

The most important aspect of gaining additional gas reserves at modestly higher prices that will get us through another decade or two is that it will help us avoid something approaching social and economic disaster. During these coming decades you would have the opportunity to plan for the widespread utilization of alternate energy sources of which coal must figure prominently. We will ultimately need the equivalent of 10 billion barrels of crude oil a year which is what we now burn in the form of oil and gas.

A delay in constructing the gas pipeline and associated delay in marketing North Slope gas will not hurt the economy of Alaska nor will the gas be lost. When, ultimately, it would be produced it will have greater intrinsic value to the people of Alaska, of the people in the other 49 States, and I daresay the world. There is a good chance, given a delay in its withdrawal, it will never be burned but converted to the useful products which can be made with equivalent efficiency only from gas itself.

Senator BARTLETT. Professor Doscher, could you comment on what the current plans are for gas injection in the time of 1983 or in the time shortly after that when the gas line might be operative?

Dr. DOSCHER. Plans now call for injection of the gas produced in the first 4 or 5 years at which time a maximum production of 2 billion cubic feet, net withdrawal of 2 billion cubic feet is planned.

Senator BARTLETT. Have you taken into consideration your figures that gas injection——

Dr. DOSCHER. There will be no gas injection after 5 years according to the current plan.

Senator BARTLETT. My question was have you taken into consideration in the figures that you are giving us the current injection plan?

Dr. DOSCHER. Yes.

Senator BARTLETT. I see. I will reserve some questions for later on. Senator Jackson?

The CHAIRMAN. Senator Durkin had a number of questions. I will ask them for him if that is all right.

Senator BARTLETT. Yes.

The CHAIRMAN. I am a little surprised about this testimony. I wanted to ask you what is your professional background. You are a professor of petroleum engineering.

Dr. DOSCHER. And a consultant.

The CHAIRMAN. At USC.

Dr. DOSCHER. Yes.

The CHAIRMAN. You have been involved in a number of assignments as a consultant and so on—over how long a period of time?

Dr. DOSCHER. I retired from a major oil company a year and a half ago. During 25 years I was consulting petroleum engineer for the head office, exploration and production department of this oil company.

The CHAIRMAN. Which oil company?

Dr. DOSCHER. Shell Oil Co.

The CHAIRMAN. You were with them for how long?

Dr. DOSCHER. Twenty-five years.

The CHAIRMAN. Now you are a professor at USC?

Dr. DOSCHER. Yes.

The CHAIRMAN Were you involved worldwide?

Dr. DOSCHER. Yes. Worldwide.

The CHAIRMAN. What in your judgment is the total amount of oil in place in the reservoir?

Dr. DOSCHER. Twenty billion barrels.

The CHAIRMAN. Twenty billion in place?

Dr. DOSCHER. Yes.

The CHAIRMAN. If you don't take the gas out, what is the total recoverable amount of oil in your judgment?

Dr. DOSCHER. This number is not available. It was a number which was not presented in the testimony presented by the operators during the work done under the auspices of the State. I cannot estimate that without going through the rigorous procedures that are required.

I would say it would be in excess of that quantity which is now anticipated of 8 billion barrels.

The CHAIRMAN. We have been talking about 9 billion as a recoverable amount.

Dr. DOSCHER. I think the evidence given, the testimony given at the May hearings in Anchorage would suggest that it is now probably closer to 8.

The CHAIRMAN. That is——

Dr. DOSCHER. That is with gas injection.

The CHAIRMAN. That is associated gas with it.

Dr. DOSCHER. That is with producing 2 billion cubic feet of gas per day starting 5 years after production.

The CHAIRMAN. What would be the recoverable amount of 20 billion in place if the gas is not taken out?

Dr. DOSCHER. It would be somewhat higher than that. There is the other point which has to be made. You see I can't estimate that without going through the rigorous procedures——

The CHAIRMAN. I am trying to get a feel here.

Dr. DOSCHER. There might be another 2 billion barrels.

The CHAIRMAN. How much?

Dr. DOSCHER. Another two.

The CHAIRMAN. So in taking the gas out, what you are saying is you might lose 2 billion barrels?

Dr. DOSCHER. You might still lose more than that because when it comes time, if we do decide to go ahead with tertiary recovery operations——

The CHAIRMAN. I was just talking about conventional means.

Dr. DOSCHER. I would estimate that and there are some data provided by other consultants to the FEA in earlier studies which suggested that it could be on the order of 2 or more billion.

The CHAIRMAN. Two or more billion.

Dr. DOSCHER. But I cannot substantiate those, Senator, because I have not done the work myself.

The CHAIRMAN. Well, I understand. But you have talked with people who have done the work. Are they reliable, competent people?

Dr. DOSCHER. Yes. I would think there is reliable evidence showing a greater recovery that way.

The CHAIRMAN. What if you utilized all of the known means, the secondary, tertiary recovery techniques. How much would you take out of the 20 above and beyond the 8 and assuming the removal of the gas?

Dr. DOSCHER. There is no tertiary recovery technique which we could say will work. There is much belief that the use of carbon dioxide will work, although this has not been proved. Should carbon dioxide work, it would work all the better had the reservoir pressure been maintained.

The CHAIRMAN. That would mean maintaining the gas?

Dr. DOSCHER. Exactly. And were that to happen, I would say—or the system to work, you would be looking at possibly another net 4 billion barrels of crude.

The CHAIRMAN. In other words, what you are saying you would get eight plus four if you kept the gas in and didn't remove it and you used modern techniques, secondary, tertiary and whatever?

Dr. DOSCHER. I am saying this possibility exists.

The CHAIRMAN. Of another 4 billion?

Dr. DOSCHER. The possibility exists.

The CHAIRMAN. I just want to get a rough idea. In other words, the recovery of 12 out of the 20 in place billion barrels—if you take the gas out and you employ secondary, tertiary and all other current known techniques, how much would you get additionally beyond the 8 billion?

Dr. DOSCHER. This is difficult to estimate because we don't have this science under our belts. It could be that you wouldn't get any of that additional. It could be you would get a fraction of it. The research has not been done to a point where I can give you the ultimate answer. I can just say that with pressure I would have a much, much greater chance of recovering a maximum quantity of the residual crude oil and without pressure my chances go down very rapidly because I would have to build that pressure up again with the carbon dioxide, for example, I would have to inject.

The CHAIRMAN. Well, it is kind of hard for us to get a picture of this thing with so many——

Dr. DOSCHER. That is exactly my point. The necessary research and development work, the necessary studies have not been done and they could be done in a manner of a few years to get a very good handle on this. In that period of time a delay in the sale of gas may give the opportunity of ascertaining whether this procedure is as effective as suggested.

The CHAIRMAN. We will not be taking any gas out until 1983.

Dr. DOSCHER. That is right.

The CHAIRMAN. How long a delay——

Dr. DOSCHER. I would think a matter of 3 years, let's say.

The CHAIRMAN. 1986?

Dr. DOSCHER. Yes. This would give us 3 years to observe the efficiency of the gas expansion in the gas cap and to know how well it is doing, whether it is doing as well as the operator surmised it will do.

The CHAIRMAN. What you are saying is that scientifically, from a professional point of view, you cannot extrapolate from the given set of circumstances without having actually gone through the experience because you are beyond that point from the scientific point of view?

Dr. DOSCHER. That is absolutely right. We have no experience. We are in this particular method of exploitation, it has been used before, in any reservoir, small or large, and given the high recovery of efficiency that is suggested by the operators which they have suggested will be achieved.

The CHAIRMAN. The President's decision, I understand, assumes the use of water or carbon dioxide for reinjection; is that correct?

Dr. DOSCHER. I am not sure of that, sir.

The CHAIRMAN. That is what staff informs me.

Now, in light of that, what is your comment?

Dr. DOSCHER. I can't see that. It could have been predicted. Certainly I can say this: the operators did not intend to do major water flooding at an early time. As a matter of fact, as I have noted in the testimony, they have said we will wait and see what happens and it is exactly that philosophy that I am saying would also tell you to wait and see what happens before you start withdrawing large amounts of gas because you can't predict exactly what is going to happen with these reservoirs.

We must wait and observe just how the thing is going. Then in 2 or 3 years you may be able to make very specific plans for either water flooding, possibly carbon dioxide reinjection, possibly a combination of both, or possibly the present system will improve in 2 or 3 years to be as efficient as it must.

The CHAIRMAN. I take it there is a conflict in the point of view of the people who have the main responsibility up there to produce petroleum. I assume that they want to get that oil out and they would like to sell the gas, too, but they don't agree with your analysis here at this point, or do they?

Dr. DOSCHER. I don't think they have had the opportunity to look at it as yet.

The CHAIRMAN. Has that been made available to them?

Dr. DOSCHER. I don't believe it has yet. No. But I will say this——

The CHAIRMAN. I am just a layman up here asking foolish questions. I don't know what to ask you.

Dr. DOSCHER. The conclusions of our report are in opposition to their conclusions.

The CHAIRMAN. What do we do?

Dr. DOSCHER. I would recommend that you delay the sale of gas.

The CHAIRMAN. You would delay this three years.

Dr. DOSCHER. That is right.

The CHAIRMAN. I have these questions here that are from Senator Durkin.

What do you believe are the major deficiencies that are present? You have covered that.

Mr. DOSCHER. That is exactly right.

The CHAIRMAN. That is the major one.

Could you explain why the producers of the oil are choosing a course by which substantial amounts of oil may be lost to the recovery of the gas resource, thereby choosing a course which may cost them billions of barrels of oil? You are saying that the loss will be at least two billion barrels.

Dr. DOSCHER. That is right.

The CHAIRMAN. Why are they doing that?

Dr. DOSCHER. Because they do believe that even with the decrease in pressure, they will recover 40 percent of the crude. We are questioning that.

The CHAIRMAN. I understand. Your professional judgment differs with theirs. That is what the heart of it is.

Dr. DOSCHER. That is exactly true.

The CHAIRMAN. What do you think would be the best approach to maximize oil and gas production in Prudhoe Bay to do both, wait three years, basically.

Dr. DOSCHER. Essentially, wait three years and amass a tremendous monitoring program of the performances in the field in which you actually observe whether the present proposal, whether the expanding gas will reduce the oil situation to the low values that are anticipated, and at the same time do the research that is required to see if water injection or carbon dioxide injection, or both, will significantly enhance the recovery of crude oil.

The CHAIRMAN. When did you reach these conclusions? This is the first I have heard of this.

Dr. DOSCHER. As I said, the report was only submitted in first draft only about three days ago.

The CHAIRMAN. That makes it pretty difficult. I have great respect based upon your professional career of the points you have raised. We are right in the middle of a project before the committee.

It is something I think we want to look into because obviously the point you have made, as a layman sitting here, I think needs a response from those who differ.

Dr. DOSCHER. Yes, sir.

The CHAIRMAN. It would be good, I think, to have all of you at one table, then I would be more confused, maybe.

Dr. DOSCHER. Possibly.

The CHAIRMAN. But at least we would be able to get a chance to question the diversity.

Dr. DOSCHER. That is true.

Senator BARTLETT. Chairman Jackson, those are very good questions and I think they have thrown a lot of light on this matter.

If I may follow up, you mentioned, I think, that it took 3 years in order to see how it works. And yet you are suggesting a decision that would delay the whole project for 3 years without that field. How do you explain that? Or am I confused?

Dr. DOSCHER. I believe—and I am recommending to you that the project should be delayed for a matter of 3 years during which period you will be able to make the observations to see how the work is performed.

Senator BARTLETT. You are suggesting during that period of time that there be withdrawals of gas?

Dr. DOSCHER. No. In the first 3 years it would be recycled, but as the oil column moves down, as the oil column moves down, we would be able to go into the core holes and measure the efficiency with which the oil is being displaced by the expanding gas column.

If it is that efficient, then you will be allowed to withdraw gas and not interfere with that.

If, on the other hand, you find that the gas is leaving a lot of oil behind, then you will have to maintain pressure in order to get a reasonable recovery of crude oil.

Senator BARTLETT. Would there be an option at that point to enter into a common project as an alternative method?

Dr. DOSCHER. Absolutely.

Senator BARTLETT. Of maximizing the amount of total withdrawal of crude?

Dr. DOSCHER. Absolutely. You will have that choice at that time.

Senator BARTLETT. Could we go back maybe a little bit before on this discussion? Could you describe the reservoir?

Dr. DOSCHER. The oil column is some 200 feet thick and the gas cap is a major gas cap overlying the oil.

Senator BARTLETT. How thick is that?

Dr. DOSCHER. It varies. At one end it is essentialy zero and then it reaches the peak of several hundred feet.

Senator BARTLETT. Are there shale breaks or limestone breaks? Is there any separation?

Dr. DOSCHER. It is in presure equilibrium at this time, although there are shale breaks in some areas.

Senator BARTLETT. Is there a shale break between the gas and the oil?

Dr. DOSCHER No. not in general. This is a free gas contact. It is not affected by shale, this continuity.

Senator BARTLETT. What part of the gas produced would be gas from the gas cap or would it be solution gas?

Dr. DOSCHER. Most of the gas would be solution gas. As a matter of fact, the operators have long noted the danger of withdrawing the gap cap gas earlier and to this extent, of course, they will be drilling. They have gotten permission to drill wells on closer spacing to avoid the coning which would result from the gas cap production.

Senator BARTLETT. If the operators produced this and concluded that you are right or concluded that they should engage in water flooding or carbon dioxide, would that action that they would then take tend to reduce the gas production that would later be producible by forcing the gas into pressure?

Dr. DOSCHER. No; the oil is now saturated with gas and unless you raise the pressure, which I don't think you would do, the object is to maintain pressure, you can't get any more gas in the solution.

Senator BARTLETT. I see. So there would be a self-defeating——

Dr. DOSCHER. No; it would only delay the sale of gas, the delay of utilization. But I don't believe that a significant amount would be lost because of that.

Senator BARTLETT. Do you think the operators—you have already stated, I think, that you feel they have a differing engineering point of view than you.

Dr. DOSCHER. Oh, yes. It is not a difference in point of view, let's understand that. It is based on their use of a relationship between saturation of oil and gas based on some laboratory experiments which we do not believe will be attained in actual practice during the rather short life of this field.

Senator BARTLETT. The engineering facts, then——

Dr. DOSCHER. Were you to produce oil in this field, let's say, 100 barrels per day, their assumptions would be absolutely valid. In other words, there would be enough time for a complete separation of oil and gas at the low gas interface. Over the shorter life of the field, we do not believe and cannot find any evidence that such as happened in actual practice, that there will be such a low residual oil saturation in the expanding gas cap. We cannot verify this in actual practice.

Senator BARTLETT. You state that the 40-percent recovery factor is high.

Dr. DOSCHER. Yes; it is high for a reservoir without major water flooding. It is a high recovery efficiency.

Senator BARTLETT. How long would it be, the normal estimate?

Dr. DOSCHER. For primary production, oil viscosity would be on the order of 25 percent and it is with water flooding that this is raised to the order of 40 or 50 percent.

Senator BARTLETT. Senator Stevens.

Senator STEVENS. What has been the industry average of the recovery in the past?

Dr. DOSCHER. Overall?

Senator STEVENS. Yes.

Dr. DOSCHER. Thirty-two percent.

Senator STEVENS. Thirty-two percent?

Dr. DOSCHER. Yes, sir.

Senator STEVENS. So this is slightly in excess of this anyway?

Dr. DOSCHER. Absolutely.

Senator STEVENS We are talking about a time frame for construction of this pipeline of at least 6 years.

Dr. DOSCHER. Yes, sir.

Senator STEVENS. So that the effect of your suggestion would be that we should not even make a decision to start that pipeline until 1986?

Dr. DOSCHER. That is right, because once you are started, you are committing the expenditure of on the order of 20 or 30 billion dollars. Now, should it turn out that you can't afford from the idea of saving crude oil to sell that gas—

Senator STEVENS. I am so confused about when you think the decision should be made. We are producing oil now.

Dr. DOSCHER. Right.

Senator STEVENS. And about one-sixth of the production is gas.

Dr. DOSCHER. That is being reinjected.

Senator STEVENS. I understand it is being re-injected, but I am told that the reinjection can keep on until 1990 without any problem.

Dr. DOSCHER. Right.

Senator STEVENS. You are saying that we ought to delay the decision as to whether the pipeline should be built for 3 years from now?

Dr. DOSCHER. Yes.

Senator STEVENS. If we are not going to produce any of the gas cap in that period of time, how are you going to get any impact on whether or not—

Dr. DOSCHER. Yes, because you will be observing the gas/oil contact. As you produce the oil, the gas/oil contact is going to move down. It has got to move down. You are going to withdraw oil so the gas/oil contact moves down and it is where it moves down that you want to go in and measure where the residual oil saturation is in those few feet of movement of the oil cap.

Senator STEVENS. You are suggesting that as we produce the oil that there may be an increased solubility and it will move into the oil and we will be producing more oil and gas as we produce more oil as the years go on?

Dr. DOSCHER. Let me try to say it this way. In the oil column every core is filled, 70 percent of that core space is occupied with oil. OK?

Above it is gas. OK? Now, as we produce oil that interface between the oil and gas will move down, but where the oil originally was, there will be some residual oil left behind.

The operators suggest that that residual saturation will be low, extremely low, 15 to 0 percent. We believe it will not be low. We believe it will be on the order of 35 percent of that core space. It will still be filled with oil.

Therefore, we believe a greater amount of oil will be left behind as the gas moves down.

Senator STEVENS. You produced this report for the Alaska State legislature; right?

Dr. DOSCHER. Yes, sir.

Senator STEVENS. Have you given a copy of it to this committee?

Dr. DOSCHER. No, sir. It is not mine to give. You will have to get it from the State.

Senator BARTLETT. Can I interrupt?

Senator DURKIN. Could the Senator yield?

Senator BARTLETT. You said that the operators claim that the residual oil saturation in that part of the column that would be depleted of oil production, they say it would be zero?

Dr. DOSCHER. Approaching zero.

Senator BARTLETT. Have you known reservoirs where it has approached zero?

Dr. DOSCHER. We have not been able to find any.

Senator BARTLETT. What is the lowest residual oil saturation, to your knowledge, where the oil/gas contact has dropped below?

Dr. DOSCHER. On the order of 25 or 30 percent. There are some reservoirs in California which have been produced for a long, long period of time. Some of the fields in the Lincoln area have been produced for 50 to 100 years.

There you do find the residual is approaching 5 or 10 percent. These are very permeable sands, but a long period of gravity grains.

Here we are not going to have a period longer than 20 or 25 years. This is a time dependent function. There is no question about that. If you wait for a million years, there will be no oil left in the gas cap.

The CHAIRMAN. If you would just yield on this point for clarification.

Senator STEVENS. May I clarify one point before? You said it was a draft report. When will it be finished?

Dr. DOSCHER. I believe they will accept the final draft this week.

Senator STEVENS. And you gave it to the State legislature?

Dr. DOSCHER. Yes, sir. Gregg Erickson, the Director of Research for Legislative Affairs.

Senator STEVENS. I don't know if that it what you are going to follow up on.

The CHAIRMAN. What I want to know——

Senator STEVENS. We could request a copy of it.

The CHAIRMAN. I wonder if there are bootleg copies around?

Senator DURKIN. Mr. Chairman, I do have a bootleg copy.

The CHAIRMAN. You just happen to have?

Senator DURKIN. I am not sure how we got it.

Senator STEVENS. Is that the report?

Dr. DOSCHER. It can only be one of the early drafts.

Senator DURKIN. It says this is a discussion draft.

Senator STEVENS. Let's get a final draft through official channels.

The CHAIRMAN. Let me ask this question. We have the two Senators from Alaska here. If they could tell us what does the State of Alaska plan to do with the report. I ask that question because—I will ask to be corrected if I am wrong—the State of Alaska, the State has the legal authority to prohibit production.

Senator STEVENS. You understand this is a legislative committee now, not the State. The State's position is in favor of this.

The CHAIRMAN. I am assuming maybe too much. But it is a part of the State government. What I want to know——

Senator GRAVEL. The problem, Mr. Chairman, is that our State has put down for the State legislature to be headed up. (sic) So, obviously, if that becomes known, it will be in the same dilemma as this committee.

Senator STEVENS. There is a little extracurricular activity called an election and Mr. Chancy Croft is running. I am not sure what this means, really.

The CHAIRMAN. Here we have——

Senator GRAVEL. I think we have to assume that the State legislature and the Governor will take the same action as this committee, that is, to bring forth all of the parties into a conference. I would hope that this committee would do that so that we could get to the bottom of these very technical things.

The CHAIRMAN. We have so many things pending before this committee. Let me just finish my point.

Are we going to be in a situation here, in light of this report and in light of the testimony that the State of Alaska could decide they are not going forward with the production at this time? Do you gentlemen want to speculate on that? Isn't that the bottom line here?

This is State property. This is not Federal property.

Senator STEVENS. I would state, Mr. Chairman, there is a group in the State that opposes the pipeline. I did not expect the issue to surface in Washington first. This gentleman obviously is partially responsible for that theory.

Dr. DOSCHER. No, no. I am not. We prepared a technical report. We are paid for that——

Senator STEVENS. I am not accusing you of anything, sir. Could I just tie this down?

Let's ask the legislative committee to supply us with reports and the State of Alaska and the Department of Energy and the General Accounting Office and let's get something for review.

The CHAIRMAN. Let's send a wire to get that in here right away because what I would suggest—and I hope it will meet with the approval of the committee—I would like to have Dr. Doscher back here with the representatives of the producers, basically the two large ones that are in the field—I believe it is Arco and BP and Exxon.

And get them all around the table here at once. I don't want to have one in.

Dr. DOSCHER. That is fine. That is fine.

The CHAIRMAN. That way we can go from one to the other.

Senator STEVENS. Could I ask the Senator from New Hampshire—he had this and I inquired and I was told—I was told this was a preliminary draft. It was not completed beforehand. And when the completed portion was available, it would be made available.

Again, my question is he has got something here, we don't know whether it is a preliminary draft or what it is.

When will we expect a final report from your organization?

Dr. DOSCHER. The final draft should be on an airplane to the State Legisative Affairs Office on Monday morning. This is a discussion draft. Only the first three chapters.

Senator DURKIN. Mr. Chairman——

Senator BARTLETT. If I could, while we are on this point——

Senator DURKIN. I think maybe this will clarify it if I could just make this further suggestion.

Senator BARTLETT. You can make it just after. I want to follow up on one thing. Then you can make it.

I think the Chairman's statement recommending this hearing with the engineers from the companies is an excellent one because you are saying that their basis of determining withdrawals as based on the withdrawal of oil be produced in the—is approaching zero and I have not heard this before. This would be a far-reaching conclusion that you are attributing to them.

So I will be very interested in what they have to say.

Now, I recognize——

The CHAIRMAN. We are not passing any judgment on this. With Dr. Doscher's background of 25 years with Shell and apparently a distinguished professional career, I am kind of intrigued with the sudden turn here by your testimony and I think it is worthy of calling in the other side. As you know, there are three sides to everything—your side, my side and the right side.

Dr. DOSCHER. That is right, sir.

Senator DURKIN. Mr. Chairman, if I could suggest—I gather that after spending 10 days in Alaska that D–2 isn't the only issue up there.

I was wondering if we might get a copy of the discussion draft to Dr. Schlesinger's department and the GAO and have them take a look at it and see if there is something to concern us here and then we could get them all in at the same time.

Senator STEVENS. Would the gentleman yield?

He said he is going to put this on a plane. Even the State doesn't have the final version yet, we will assure you, I am sure, my colleague and I, we will have authority of this gentleman to send the committee and whoever else in the government wants copies of this, as it goes to the State. We will obtain that today. [See p. 340.]

Then we can decide what happens to it.

Senator DURKIN. We are operating under certain time constraints and we should make a decision on hopefully the most up-to-date evidence.

The CHAIRMAN. We have until the 22d for the committee to act, but they are going to discharge us after the 22d of October. Those are the constraints.

Dr. DOSCHER. I do want to go back to one point which I don't think should be lost. That is the last couple of paragraphs of my testimony said that even though gas withdrawals would not effect oil recovery, that the amount of gas that can be made available from the Prudhoe Bay field only amounts to three-quarters of a trillion cubic feet a year. This is less than 5 percent of direct consumption. This gas will cost, I believe, significantly more than any number that has been quoted here today.

Significantly more. I think it will approach the order of $5 a thousand cubic feet delivered to the United States.

Senator BARTLETT. How does that producible reserve compare—are you differing with the producible reserves of the companies?

Dr. DOSCHER. Not the reserves. I said the cost. The number I quote, the three-quarters of a trillion is exactly what they say that can be withdrawn. This is their number. Three-quarters of a trillion.

Senator STEVENS. But you are talking transportation costs; aren't you?

Dr. DOSCHER. That is purely transportation cost because you can take three-quarters of a trillion a year and pay out in 20 years and take the cost of the total pipeline system at $20 billion or $30 billion.

You are looking at transportation costs of $4 or $5 for a trillion cubic feet a year.

But you can get that trillion cubic feet from a lot of other sources.

The CHAIRMAN. Aren't there two compelling factors here, even with your fine professional expertise and judgment. This is just a suspicion on my part.

I think the industry wants to get their money out as fast as possible and their gas and their oil early. And I have a sneaking hunch that the State wants to get a lot of revenues out at the same time, so that their interests are mutual.

Dr. DOSCHER. I am not sure of that. I don't know that they point this out in the report. I am not certain that the interests of the State and the operators are necessarily parallel.

Senator STEVENS. There is a substantial feeling in the State that there are conclusions to support.

The CHAIRMAN. I just have a feeling with the State wanting revenues, they want to get it fast when the legislature meets and makes a decision and looks at the amount of revenue that is available.

Dr. DOSCHER. The amount of gas revenue would be fairly small compared to the oil revenue.

Senator STEVENS. That is a point. Besides that, our conservation commission is very, very strong and they will make the final determination.

The CHAIRMAN. Then we have a good chance that the State will not let the gas go.

Dr. DOSCHER. I don't know. This would be for the State to decide.

Senator BARTLETT. It seems to me that you are making a good point for deregulation of gas in the lower 48.

The CHAIRMAN. That is what happens when I turn over the chair to him.

Dr. DOSCHER. I didn't say deregulation. I said for a smaller cost than the cost of Prudhoe Bay gas, a trillion cubic feet of gas could be provided for a smaller cost.

Senator BARTLETT. We can draw our own conclusions from the statement, I suppose.

The CHAIRMAN. The cost you should put on that wellhead——

Senator DURKIN. Isn't it true that the oil is more important to Alaska and also more important to the lower 48 than the gas we are talking about?

Dr. DOSCHER. It is one-third——

The CHAIRMAN. Wait until we go through a bad winter. It is still fall. The Almanac says it is going to be another cold one.

Senator DURKIN. This is going to be as bad as the winter of Valley Forge.

Senator BARTLETT. Gas is not so readily substituted by imported gas. I think that limits to what that can be other than what the 50 States can provide.

Senator GRAVEL. I think the question you pursued was after 3 years the Congress would be in a position to know whether or not to flood.

Dr. DOSCHER. The State would be in a position to know.

Senator GRAVEL. With flooding, would you be altering the quantities of oil that could be withdrawn?

Dr. DOSCHER. No. If anything, you would be increasing it.

Senator GRAVEL. So if we went ahead and then produced the gas and based upon the evidence that was discovered, just went ahead with flooding after that, that we would not lose any gas or lose any oil.

Dr. DOSCHER. No. You would probably get more.

Senator GRAVEL. As I understand it, to my knowledge that was all part of the premise to begin with, when the Government approved this, that flooding would come on-line. They would hold off the flooding until they had some experience which is essentially what you are saying.

Dr. DOSCHER. Exactly. But I am also saying you must hold off plans to withdraw the gas. The important thing is you must not commit the 20 or so billion dollars for building a pipeline until you are certain that you can withdraw that gas without effecting the ultimate recovery from the reservoir.

Senator GRAVEL. If you had a possible decision to flood, you would obviate that difficulty; wouldn't you?

Dr. DOSCHER. Not certainly.

Senator GRAVEL. How close to certainty is it?

Dr. DOSCHER. This is why we have to wait and observe the performance of the reservoir for several years.

Senator GRAVEL. If we went ahead and decided to flood, what do you subject yourself to in terms of possible loss? I mean what is the probability of error if we say that after 3 years we will flood, how much gas would we lose? What is the outside?

Dr. DOSCHER. It depends on how quickly—you see, if you decide to water flood in 3 years and make that decision, it is not likely you will have full blown water flooding for another 3 years because you have got to require something like a billion barrels of water someplace and inject it in that reservoir.

Senator GRAVEL. We are not far from the Arctic Ocean.

Dr. DOSCHER. That is true. But the water that gets ingested into an oil field has to be an awful lot cleaner than the water you drink.

Senator GRAVEL. That is pretty clean water up there.

Dr. DOSCHER. I think if you have observed the problem that we have in oil fields around the world, no matter how clean you think it is——

Senator DURKIN. Wouldn't that cause a lot of problems by overflooding the field?

Dr. DOSCHER. I wouldn't know that.

Senator BARTLETT. Did you consider the question—or should you, on what is more important to the Nation, more gas later or more gas now?

Dr. DOSCHER. That is an important question to decide.

Senator BARTLETT. Could you make a comment on that?

Dr. DOSCHER. I would think the oil supply is the one you have to guarantee because this is where we are much more vulnerable, far more vulnerable in terms of oil supply because right now we are depending on foreign countries to supply us with half of our fuel needs.

Our own production is only good for 40 or 50 percent. If we are shut down for 90 days, we don't have any oil to operate with.

Senator BARTLETT. Another question. How much—did you say that 2 billion barrels of oil would be lost?

Dr. DOSCHER. It could be.

Senator BARTLETT. I think you commented on this earlier. I would like to ask you again would that normally be recoverable, that lost oil, by water flooding or CO_2 injection?

Dr. DOSCHER. A good part of it might be ultimately recovered. Yes, sir. I cannot deny that.

Senator GRAVEL. But you are not specific on that?

Dr. DOSCHER. I can't without going into the—let's say, half of it and then the additional quantity you would get by a tertiary process.

Senator BARTLETT. If I could just follow that a second. The gentleman from Alaska is making a good point here. In the normal gas reservoir, when you produce it by primary means and then come along later with water flooding, but did not have gas injection or pressure maintenance, is this generally considered that recovery of the oil includes the oil that was left because of the lack of pressure maintained with gas injection?

Dr. DOSCHER. You will never recover as much oil from a reservoir if you allow the pressure to decrease and then subsequently get water flooding going. There are some countries in this world that require you to initiate injection on day 1 if there is no natural water drive and this is to avoid the loss of crude oil due to the phenomena known as shrinkage which accompanies pressure reductions.

In the North Sea, for example, at this time most of the fields are very similar in nature to that of Prudhoe Bay.

Senator BARTLETT. Do they require injection?

Dr. DOSCHER. They have water injection from day 1.

Senator BARTLETT. Do they have other injection if there is not a water drive?

Dr. DOSCHER. They require fine water and put it in.

Senator STEVENS. May I ask a question here?

Senator BARTLETT. Yes.

Senator STEVENS. The effect of your suggestion is going to increase the initial price of the oil and probably the long-term price of the oil.

Dr. DOSCHER. No. I don't believe so.

Senator STEVENS. If we are to reinject, there is a cost for reinjection. If we reinject longer, it would seem that that would increase the cost of the oil. Also, if we were to postpone the production of the gas, it would seem then that the oil must play a total cost of field development.

Dr. DOSCHER. I believe right now the economics are based, for pricing the oil, are based on oil production, per se. In other words, there is no use of the gas revenues to defray any cost of producing the oil. I am quite certain of that.

Also, I would also say that the amount of energy required in the actual cost of re-injecting the gas compared to the price at Valdez is trivial. Also, there is much more cost at transporting it to Valdez, then the additional cost of reinjecting gas will probably only appear in a decimal point. I will venture to say that probably you are right on that.

Senator STEVENS. And I have not seen the total quoted.

Did you examine any alternative uses of the oil, such as the methanol and other processes, I mean uses of the gas?

Dr. DOSCHER. Yes. Well, you are going to get to a point, one of the recommendations was that the State should consider acquiring the gas on its own and ultimately sponsor or be partner in a tremendous petrochemical industry in Alaska; that this could have probably far more lasting value for the people in the State of Alaska and for the country.

Senator STEVENS. Thank you, Mr. Chairman.

The CHAIRMAN [presiding]. Senator Durkin. Then we will hear from Senator Gravel who has a statement he wishes to make as a witness.

Senator DURKIN. Thank you, Mr. Chairman.

I just want to clarify one or two statements. I would like to commend Dr. Doscher. I think he has performed a valuable service for this committee and we will take this into account before a final decision is made on the pipeline.

My question is, you mentioned 2 billion barrels of the Prudhoe Field would be lost and then later on that four billion barrels could be lost with respect to tertiary recovery. Is that a total of four or a total of six?

Dr. DOSCHER. Again, all this is a could be. It could be six. Yes, sir, because I don't know without seeing the research and development work to exactly what CO_2 could do and what pressure was required to make it work. All I am saying is that we must do this because that is a potential we can't afford to overlook.

Senator DURKIN. And you agreed that the oil is more important to the United States?

Dr. DOSCHER. This is my personal opinion now.

Senator DURKIN. More important than the gas supply?

Dr. DOSCHER. Absolutely.

Senator DURKIN. I think the committee is presented with a problem. You have heard today we talked about having Dr. Schlesinger review the report and having GAO take a look at it and BP and ARCO and I guess Exxon.

What would you recommend as steps so that the committee could resolve this question within the timeframe that we have?

Dr. DOSCHER. I think the decision should be based on whether there is any possibility that the present mode of production might not recover as much oil as proposed. And if that is true, I think we can well afford to wait a three year period.

Senator DURKIN. But how do we do that? We are faced with a certain time constraint. How do you recommend to this committee—?

Dr. DOSCHER. I would have to say you would turn down the pipeline at this time.

Senator DURKIN. That is a rather drastic solution at this time.

Dr. DOSCHER. Can you go ahead with it and pending the three years of observation, then make the observation to go ahead and construct?

Senator DURKIN. Let me back up. Maybe this was not as clear as I thought it might be. We are faced with a dilemma. One solution is to scratch the pipeline and see what happens. But short of that, there are a lot of things at stake here for a lot of people, some in the room and some consumers.

But, how in the time frame we have do you think this committee should proceed to resolve the substantial questions that you point out?

Dr. DOSCHER. I think Senator Jackson's proposal is the only alternative. To have some people here representing the various opinions and you ascertain whether it is worthwhile to delay it for 3 years on that basis. It is a drastic solution.

Unfortunately, the energy problem is facing this country, all require drastic decisions. We are running out fast and we are going to be desperate.

Senator DURKIN. Thank you, sir.

Do you endorse the chairman's approach to have Dr. Schlesinger review it and have GAO review it?

Dr. DOSCHER. Let me say that I think you will get what you need from having the people representing the operators and myself sit down and show you where the differences are. I really do. I don't think you have to go beyond that.

Now, certainly you might want Mr. Schlesinger's people to participate and give you an opinion, but I don't think a full blown analysis is necessary. As you will see, it is a matter of what is the right input.

I am saying I don't think we know and they are hanging their hats on one of the possibilities.

Senator DURKIN. The bottom line is you say if our assumptions are correct that we could lose effectively 6 billion barrels of oil out of that field?

Dr. DOSCHER. I think this is a possibility.

Senator DURKIN. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator Durkin. Thank you, Dr. Doscher. You have added a little life to the hearing. I think the press will welcome it.

But, seriously, I was impressed by your remarks and we will ask for you to be back.

Will you be available?

Dr. DOSCHER. Yes, sir.

The CHAIRMAN. We will arrange a hearing date, presumably this coming week. It will be an early morning hearing because we will be involved in the conference. Will you be here in the city?

Dr. DOSCHER. No. You will have to get me back from Los Angeles.

The CHAIRMAN. Well, that won't be too hard.

Senator BARTLETT. Mr. Chairman?

The CHAIRMAN. Yes. Senator Bartlett.

Senator BARTLETT. On the way out I was explaining part of what you said to another person. It brought to mind another question.

Is there any chance in the plan proposed by the operators that the gas cap pressure will be reduced to the extent that the oil migration in the column into the gas cap——

Dr. DOSCHER. Oh, yes. There is great danger of this. And the operators plan to compensate for this by essentially dumping water into the gas cap in about 6 or 7 years in order to maintain the pressure in the gas cap due to the reduction and they assume you can get the water in fast enough.

Senator BARTLETT. What level would they dump it into the gas cap? Through it?

Dr. DOSCHER. Off on the side in the gas cap.

Senator BARTLETT. Would it be done in the lower part of the gas cap on the side or the middle or upper or what?

Dr. DOSCHER. Just about in the middle, as I remember the picture. Just about in the middle.

Senator BARTLETT. If oil from the oil column migrated into the gas cap, then there would be a definite loss there of residual oil.

Dr. DOSCHER. That would be disastrous.

Senator BARTLETT. What would be the saturation?

Dr. DOSCHER. You could raise it from zero where it is now to as much as 35 or 40 percent.

The CHAIRMAN. How long can you keep reinjecting the gas in this pool or reservoir?

Dr. DOSCHER. You can do it forever. The way I would think that we reinject the gas cap for 15 or 16 years to maximize oil recovery. Then at that time you could really start blowing down, as we say, the gas cap and then take it off.

The CHAIRMAN. So many of the areas in the Middle East, they are fixing it, of course. That is why they want to go in the LNG business.

Dr. DOSCHER. That is right.

The CHAIRMAN. It will depend on the nature of each reservoir.

Dr. DOSCHER. As a matter of fact, there is a manner not to just flare it. Some of the gas is being put back in and there is a question as to whether this is truly the best thing to do.

The CHAIRMAN. Well, we have had previous information to the effect that the maximum period at Prudhoe Bay area was about 1990. That would be close to 15 years that you could reinject.

Dr. DOSCHER. That is right. At that time you would start blowing it down and take the gas out.

The CHAIRMAN. Thank you very much.

Dr. DOSCHER. Surely.

The CHAIRMAN. Senator Gravel.

STATEMENT OF HON. MIKE GRAVEL, A U.S. SENATOR FROM THE STATE OF ALASKA

Senator GRAVEL. I welcome this opportunity to discuss with you the President's decision on the transportation of Alaska natural gas. This is, of course, of great concern to me and to my State. But it is also of vital concern to the rest of the Nation—for, as the decision points out, Prudhoe gas will constitute some 5 per cent of total domestic gas production in 1985—and it will amount to between 6 and 10 per cent of the total supply of gas for the Midwestern States. The decision also points out that in 1985 the line will deliver as much gas from the current Prudhoe Bay reserves as is projected to come from both accelerated OCS leasing and from imports from the Chiapas-Tabasco region of Mexico. In addition, the country as a whole gains from the project through some $5 billion dollars of national net economic benefits. So we are indeed addressing a national issue.

The administration has been successful in negotiating a favorable agreement with Canada. Approval of this agreement will permit early commencement of construction. As the President has said, it is in the Nation's interest to bring the gas from Alaska to market at the lowest possible price, and insofar as the decision advances us toward that end, I am enthusiastic about it.

But there are inconsistencies in the decision, particularly with regard to price and financeability. Specifically, I want to address the assumption that the State of Alaska and the producers should participate in financing the pipeline . . . and the assertion that no Federal guarantee should be made.

The total cost of the Alcan line will be high—perhaps as much as $13 billion. But the President's decision contends that Alcan's total long-term debt requirement in its peak year is only 3 percent of the debt market in the United States in 1976 dollars. And over the 5-year completion period, the decision says the aggregate requirement is less than 1.4 percent. The decision further points out that peak year requirements as a percentage of total market capacity are about the same as the peak year requirements of the Alyeska oil line project.

After consulting with Northwest Pipeline and the Treasury Department, the President says he has found that the pipeline can be privately financed without resort to an "all-events" tariff and without Federal Government guarantees. This conclusion is based on the economic desirability of Alaska gas and the viability of the Alcan transportation system.

I agree that these two bases are the true indicators of the financeability of the project. But I feel that logic is violated when certain parties are then, in essence, required to guarantee the project. If the pipeline can be financed through the private market, it is because the financers find it desirable and viable—not because the administration finds it so.

The President's decision maintains that the State of Alaska and the producers of Prudhoe gas should participate in either equity or debt financing. These two groups are referred to as "direct beneficiaries" expressly because they own the gas to be produced. As "direct beneficiaries", they are looked to as "obligatory" investors.

This concept of forced participation is not at all in keeping with the concept of private financing based on economic desirability and project viability. If this line is to be privately financed in any true sense of that investment term, it should occur because the project is attractive from an investment standpoint, not because of governmental mandate. Requiring the State and the producers to enter into financing of the line is improper and inconsistent with the normal course of business. It's a bit like requiring steel companies or bread bakers to participate in guaranteeing portions of the Federal highway system because they directly benefit from the transportation of their product to market.

In the specific case of the State, Alaska is considered a beneficiary because of its one-eighth royalty share of Prudhoe gas. Because of its one-eighth ownership, in other words, the State is expected to help guarantee construction of the line. The State did indicate an interest in providing guarantees for the El Paso line, because the State recognized that it would be in the interest of the people of Alaska to have royalty gas at tidewater to aid in the diversification of the State's economy. A feeder line to tidewater is still feasible, and it is possible that State guarantees might be required there. In fact, it is not difficult to imagine many project within the State that could require its ability to guarantee financing. But I do not believe the State should be expected to participate in the financing of the Alcan line. Such an "expectation" would be bad precedent in an economy where risks are supposed to be taken because of economic desirability and project viability.

As for financing participation by the producers: Traditionally, as you know, the transmission of natural gas has been accomplished by pipeline companies, not by major oil and gas producers. In fact, a recent Justice Department study has indicated that anti-trust implications would arise from the participation of major oil companies in equity financing of the Alaska gas line. Presumably, Justice would have no objection to these companies guaranteeing the debt—assuming the companies find it would make good economic sense to do so. But does it make good economic sense? At the same time that the Government is anxious to require producers to participate in financing of the gas line, it is also pointing to a shortage of domestic petroleum. I think it would make more sense for the major companies to be using their resources to find and produce new oil and gas. I do not think it is in our Nation's interest to tie up their debt-raising ability in guarantees for the gas line.

In advocating a role for producers in gas line financing, the administration implies that the gas producers have no real costs with regard to production. This is not the case. At the present time, gas is reinjected into the Prudhoe reservoir, and this enhances recovery of oil from Prudhoe. I have been told it will cost as much as 2 billion dollars to build water flood facilities for pressure maintenance of the reservoir when gas is produced rather than reinjected. In addition, the conditioning plant will cost some 1.8 billion dollars in 1975 dollars. This represents costs in the range of 70 to 90 cents per MCF. The administration's figure of zero to some 30 cents is not accurate. These costs are necessary to prepare the gas for transportation in Arctic climates. Incidentally, the conditioning plant is probably the critical factor in the early delivery of Alaska gas, since it will take four years and 10 months to construct the plant.

If requirements are to be placed on any entity to participate in financing the line, it seems only right to place that obligation on the real beneficiary of the gas—namely, the consumer. This could be accomplished with guarantees from utility companies who will receive the gas. Those costs should be built into the rates to be charged the gas customer to the extent guarantees of completion are necessary. The cost of such guarantees is truly an ingredient in the total cost of service. If we are not going to provide Federal guarantees because they would artificially lower the price of a valuable resource, then we should not artificially lower the price by requiring others to subsidize the risk of completion of the gas line.

The President's decision says the Alcan project is privately financeable. That determination is predicated in part on the participation by the State and the producers. The administration needs to advise Congress of the private financeability of the project without the participation of those two entities.

The President has found that Government guarantees for completion of the project are unnecessary and undesirable. He has thus rejected that alternative method of financing the pipeline. Federal guarantees could be justified on the basis that the Federal Treasury will be a substantial "direct beneficiary" of the project. The President has rejected Federal guarantees despite the fact that Federal guarantees could provide significant savings to the American consumer.

Federal guarantees could provide for 90 percent debt financing rather than the projected 75 percent. By use of Federal guarantees, we could save the American consumer up to 3.8 billion dollars (20 trillion cubic feet at 19 cents saving). One econometric study shows that the use of Federal guarantees would result in savings in the cost of service of 18 percent of the currently projected costs of service. On transportation of $1.04 per MCF, the savings would be 19 cents per MCF, in 1975 dollars. At $2 per MCF cost of transportation, the savings would be some 36 cents per MCF. If Federal Government guarantees were provided up to the current 75 percent debt limit, savings of some 6.2 percent of total cost of service could result. That means savings of 7 cents per MCF at $1.04, and 12 cents at $2. In my opinion, this is the best way to insure private financeability of the line.

The administration's decision explains why the use of Federal guarantees was rejected, but the explanation is not consistent. For example, the decision states that lower interest rates resulting from Federal guarantees would yield an artificially low price for gas. This is a remarkable argument from an administration which favors regulated gas prices—at an artificially low level.

The decision also says that Federal guarantees would put the Government in the role of risk assessment traditionally left to the private sector. Yet that is precisely what the decision does when it attempts to require the State and the producer companies to participate in guaranteeing completion of the project, even in the event of cost overruns.

It seems to me that the best way to assure that the line can be financed in the private market, because of the extraordinary size of the undertaking, is to guarantee completion by the Federal Government or by the ultimate consumer.

At this time I will not introduce legislation to provide for Federal guarantees in deference to the administration's conclusions. I am perfectly happy to have the private sector handle the financing, in the traditional investment sense of the word. I am sure we can all agree that the important thing is to assure the earliest possible construction of the line.

There is one note to stress and that is in light of this difficult testimony. I would add that Dr. Schlesinger and the whole Energy Department be involved in this process since they have already made a decision.

The CHAIRMAN. Well, I will ask. I will talk personally to the Secretary about this and he will want to bring in, I am sure, some experts within the Government that may come from the U.S. Geological Survey.

Senator GRAVEL. The only other thing I would ask, Mr. Chairman, is that there are two problem areas that should be cleared up. One, of course, is the conditioning plant. We could do that. And, two, the financing.

I would hope that the committee would go ahead with its approval since a year's delay is very, very vital. The financing would have a very serious problem if you put your decision over to a later time. You think the administration knows about this situation, and the financing is wrought with different facets of what should be involved.

Certainly, in the light of this information, they might be reluctant whether or not the companies would be involved. There are also problems with respect to the divestiture climate in Congress, with respect to not permitting interest on the Alyeska project.

The other facet, of course, is the possibility of an all events tariff which Congress and the administration finds an enigma at this period of time. I might say that in your part of the country and in other parts of the country, they have large water projects.

The Federal water policy is for people who have used water to pay for the capital improvements of this water. That, in my mind, is comparable to what is essentially an all events tariff.

The CHAIRMAN. But an all events tariff would put it on the consumer, even if he didn't finish the project.

Senator GRAVEL. I think we can work out the other facets. We can work this out probably in the project if the water projects you have in your area—based on the Rockefeller Commission, the whole concept was to move toward a clearing of the council for those who would be willing to pay for it.

Another possibility which is called Federal guarantee which will bring this to the consumer at a cheaper rate. I would submit that what we should do is let the administration go forward in its negotiations on findings and see what reactions we get from the private sector and the kind that warrants involvement of the committee.

If it doesn't warrant it, then we could go forward. That would be my recommendation, but I would stress that we should make a decision to go forward, assuming that these difficulties raised this morning can be set aside. We can go forward this year since time is of the essence in this regard.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator Gravel.

It is my understanding that the companies have made clear, that is, the Alcan company, that they will not need any governmental guarantees or assistance.

Senator DURKIN. Or they don't need an all events tariff.

The CHAIRMAN. I am talking now about the financing end of it. Of course, I would recommend that if we act on this, we should make very clear that there be no Federal guarantees of any kind.

Senator GRAVEL. I think the suggestion I am making, Mr. Chairman, is that you reserve judgment in that regard until a later time and not tie that down to this particular part.

The CHAIRMAN. I think we should know before—I am speaking only for myself, because the industry people made very clear to me privately and then they made it on the record that they do not need Government guarantees. So I think we have a duty, based upon the testimony here in the record, that there will be no guarantees.

I speak only for myself.

Senator GRAVEL. I think that premise is based upon Dr. Schlesinger's statement that the private companies should come in and guarantee. So they are talking about some form of guarantees. And that is the point I would like to leave open until Dr. Schlesinger is able to negotiate this out with the parties involved.

The CHAIRMAN. But the companies have said, though, that they do not need any guarantees. I don't want to impose a guarantee on them.

Usually, it is the other way around. Usually they are in asking for guarantees.

Senator GRAVEL. That is what I am saying. Why don't we just reserve judgment on that whole area.

Senator DURKIN. Mr. Chairman, wasn't that one of his strong points of the Alcan proposal, that it did not need a guarantee? I think that had a lot of impact in support of the McMillian proposal.

The CHAIRMAN. Let's get the rest of this interesting testimony first.

Senator GRAVEL. And see if we go forward from there.

The CHAIRMAN. That would help.

Senator DURKIN. I would like to footnote, if I could, as the analogy to water escapes me inasmuch as the public owns the water and doesn't own the oil.

The CHAIRMAN. The amendment that I wrote into the Alaska Statehood Act provided the State with 103 million acres. They were in trouble in the financing of the new State. They said the State would be back. Senator Atchinson and I, together, we put that amendment in and the House didn't have it. We provided a pretty good bank for Alaska, 103 million acres.

The Alaskans were wise enough to set aside in their selection process——

Senator STEVENS. The State Constitution.

The CHAIRMAN. But, no, I am saying they did select the Federal lands adjacent to oil reserve, the petroleum reserve, but so far the Federal Government hasn't had any oil. And it is Prudhoe Bay and the State that has it all.

Senator DURKIN. Is it true, Mr. Chairman, that many people think you discovered the oil in Prudhoe Bay?

The CHAIRMAN. We will adjourn on that note.

[Whereupon, at 11:30 a.m., the committee adjourned, subject to the call of the Chair.]

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

TUESDAY, OCTOBER 25, 1977

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met pursuant to notice at 8 a.m., in room 4200, Dirksen Office Building, Hon. Clifford P. Hansen presiding.

Present: Senators Hansen, Metcalf, Durkin, and Stevens.

Also present: Betsy Moler, counsel; and George Dowd, counsel.

OPENING STATEMENT OF HON. CLIFFORD P. HANSEN, A U.S. SENATOR FROM THE STATE OF WYOMING

Senator HANSEN. The hearing will come to order.

Senator Jackson had planned to be here to chair these hearings. He called me this morning saying that he would not be able to be here right at this time and asked if I would chair until he arrives.

I have a statement from Senator Jackson that I will include in the record at this point.

[The prepared statement of Senator Jackson and the GAO staff summary follows:]

STATEMENT OF HON. HENRY M. JACKSON, A U.S. SENATOR FROM THE STATE OF WASHINGTON

On October 12 the Committee received testimony from Dr. Todd Doscher of the University of Southern California that production of natural gas from the Prudhoe Bay field could have a significant adverse effect upon the amount of oil that would be ultimately recovered. Dr. Doscher recommended that the Committee delay its decision on whether to build a natural gas pipeline for three years in order to give us time to see how the field actually operates before making a commitment to producing the gas.

In response to Dr. Doscher's testimony, the Committee has requested the State of Alaska and the three largest Prudhoe Bay producers to testify at today's hearing.

Prior to today's hearing I requested the staff to conduct a review of the studies available to the public on the Prudhoe Bay production potential. Four studies of the field were reviewed, along with the field operator's production plan that was submitted to the State of Alaska. The staff was assisted in its review by two members of the staff of the General Accounting Office.

The studies consist generally of computer simulations of how the field is expected to behave. The GAO staff concludes that three of the studies—those done by Gruy, Core, and Van Poollen, essentially simulate the operations of different fields although all three claim to utilize Van Poollen data. The studies contain anomalies in several areas. All studies agree that without gas reinjection, and some type of water repressuring, there would be significant deterioration in the recovery of oil and gas. Even with the water repressuring and gas reinjection, the production profiles in the Van Poollen and Core studies are markedly different. Van Poollen shows that gas production and sales have a significant adverse effect on the short-term oil production; a loss of up to 500,000 barrels per day is likely in the short-term. Core shows no such short-term oil production loss.

The staff concludes that, "At this point we cannot ascertain the overall effect of gas production and sales on the ultimate recovery of oil from the Sadlerochit reservoir."

I hope that today's hearing will help clear up some of our unanswered questions.

I ask unanimous consent that the findings reached by the GAO staff members be reprinted at this point in the hearing record.

FINDINGS

1. We cannot evaluate Operators and D & M due to a paucity of information contained in the reports.

2. While we cannot describe the Operators and the D & M field simulations, we would conclude that of those we could, Gruy, Core and Van Poollen essentially simulate the operations of different fields although all 3 claim to utilize Van Poollen data. We find these anomalies in the following areas.

(*a*) The water drives in all three simulations are significantly different with the Van Poollen simulation having the weakest aquifer and Gruy the strongest.

(*b*) Both Gruy and Core only describe the Sadlerochit field and exclude considerations of hydrocarbons located elsewhere. Van Poollen posits a link between the gas cap in the Shublik formation.

(*c*) Core indicates that for the same field parameters, the existence of an aquifer increases oil recoverability. Van Poollen indicates the opposite, although the effect is small.

(*d*) The production profiles on a yearly basis with and without aquifers are significantly different for Van Poollen and Core.

(*e*) Similarly oil production profiles with gas sales show that the Sadlerochit field as simulated by Van Poollen does not agree with that as simulated by Core.

(*f*) We have found the estimates of oil-in-place and gas-in-place to be inconsistent among the studies and in the case of the operator study, internally inconsistent.

(*g*) We find *no* consistency, however, between the studies and the published API reserve figures as of 31 December 1976.

3. Despite these differences all 5 studies indicate either a maximum oil recovery of about 8.4 million barrels or 42.8 percent recovery of oil-in-place.

4. Production of gas from Sadlerochit requires gas cap production early on in the productive life. At 2.4 bcf a day, the capacity of the Alcan pipeline, this would require production of oil significantly above the current 1.2 million barrel a day capacity of the TAPS to avoid excessive gas cap production.

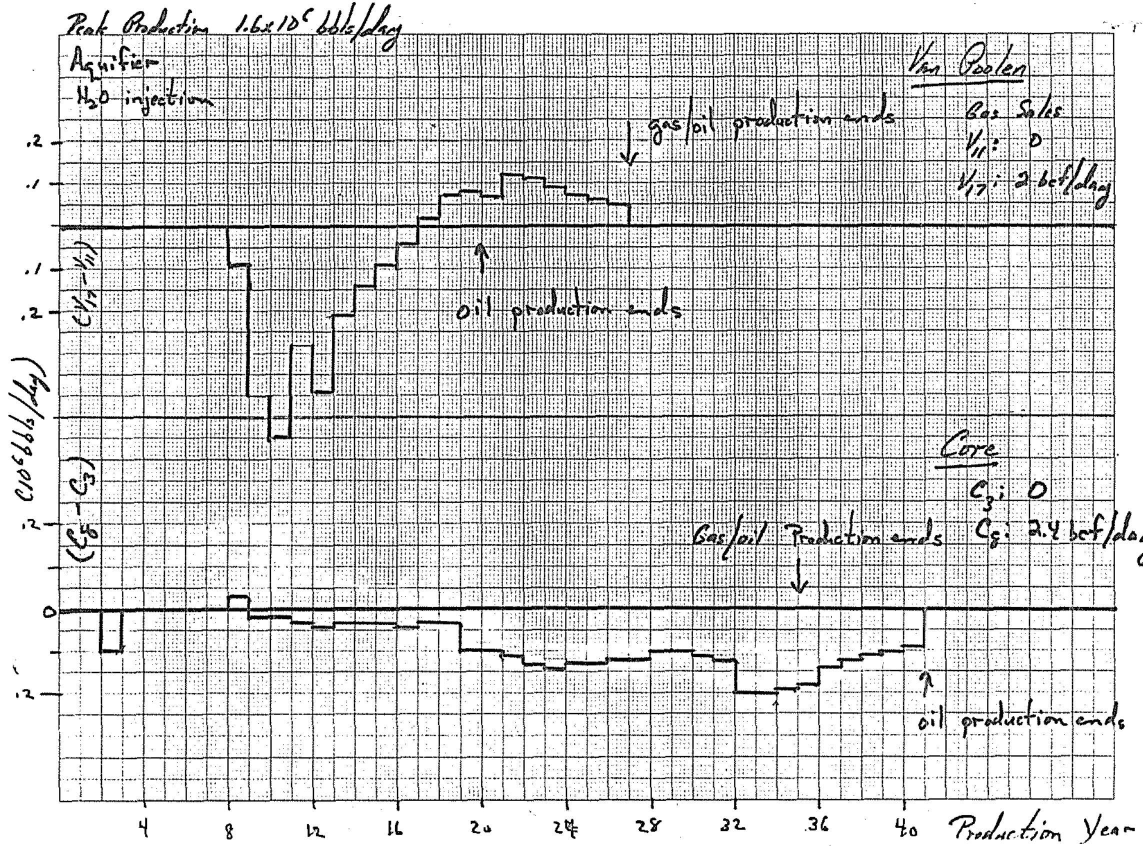
5. All studies agree without gas re-injection, and some type of water repressuring, there would be significant deterioration in the recovery of oil and gas.

6. We find that none of the studies addressed natural gas liquids which at 1.45 gal/Mcf of gas and 2.4 bcf per day pipeline throughput results in almost 100,000 barrels a day of n.g.l.

7. We find that the production profiles in the Van Poollen and Core studies are markedly different. (Note: The attached graph shows the amount that oil production is likely to increase or decrease in a given year with 2.0 billion cubic feet of gas sales per day for Van Poollen and 2.4 bcf/d for Core.)

CONCLUSION

At this point we cannot ascertain the overall effect of gas production and sales on the ultimate recovery of oil from the Sadlerochit reservoir.



Peak Production 1.6x10^6 bbls/day
Aquifier
H2O injection
Van Poolen
Gas Sales
V11: 0
V17: 2 bcf/day
gas/oil production ends
oil production ends
Core
C3: 0
C8: 2.4 bcf/day
Gas/oil Production ends
oil production ends
(V17 - V11)
(C8 - C3)
(10^6 bbls/day)
.2
.1
.1
.2
.2
0
.2
4
8
12
16
20
24
28
32
36
40
Production Year

Senator HANSEN. I am very pleased that Senator Metcalf is here, and I asked him if he would chair. He obviously is a very ranking member and very highly regarded member of this committee.

Senator Metcalf, do you have a statement?

Senator METCALF. I don't have any opening statement, but I am delighted that you are here to chair since Wyoming is a better oil-producing State than Indiana and Montana.

Senator HANSEN. Senator Stevens, do you have any statement you would like to make before we call the witnesses?

Senator STEVENS. Well, I am happy to find you. I was in room 3110.

Senator HANSEN. Well, I went that same route and I was happy that someone knew where the hearings were going to be held.

From the State of Alaska, appearing as a panel, will be O. K. Gilbreth, Jr., director, Division of Oil and Gas Conservation, Department of Natural Resources, State of Alaska; Hoyle Hamilton, chief petroleum engineer, Division of Oil and Gas Conservation, Department of Natural Resources, State of Alaska; and Dr. H. K. Van Poollen of H. K. Van Poollen & Associates, Inc., Littleton, Colo., accompanied by Robert H. Loeffler, Esq., from Washington, D.C. Will those members representing the State of Alaska who are to appear as a panel please come forward?

Gentlemen, if you or whoever is to speak first would identify yourself and proceed in whatever manner you prefer we would be pleased.

STATEMENTS OF. O. K. GILBRETH, JR., DIRECTOR, DIVISION OF OIL AND GAS CONSERVATION, DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA; HOYLE HAMILTON, CHIEF PETROLEUM ENGINEER, DIVISION OF OIL AND GAS CONSERVATION, DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA; AND DR. H. K. VAN POOLLEN, H. K. VAN POOLLEN & ASSOCIATES, INC., LITTLETON, COLO.; ACCOMPANIED BY ROBERT H. LOEFFLER, ESQ., ISHAM, LINCOLN & BEALE, WASHINGTON, D.C.

Mr. GILBRETH. Mr. Chairman, other distinguished Senators, ladies and gentlemen, my name is O. K. Gilbreth, Jr., and I am director of the State of Alaska's Division of Oil and Gas Conservation. I have prepared a somewhat lengthy statement, about 15 pages, and will try to summarize.

Senator HANSEN. If I might observe, the statement, in its entirety, will appear in the record, and we do appreciate your willingness to summarize it, sir.

Mr. GILBRETH. Thank you, sir.

My primary responsibility as director of the State Division of Oil and Gas Conservation is to regulate oil and gas industry operations to prevent the physical waste of oil and gas in the State and to protect the correlative rights of all interests in an oil and gas field. Our goal is to regulate production in a manner which will insure that maximum recovery of hydrocarbons is achieved and physical waste is avoided. At the outset I wish to emphasize that we do not set the rate of production of either oil or natural gas so long as it does not create waste.

Earlier this year the operators requested approval of the Oil and Gas Conservation Committee of their plan to operate the Prudhoe Bay field. On May 5, 1977, we held a public hearing on this plan, including a review of the proper initial rates of production. As a result of that hearing, Conservation Order No. 145 was issued by the Oil and Gas Conservation Committee. The order contains many requirements to secure data during start-up and the initial production periods to aid in determining proper methods of operation of this reservoir. Copies of the order are attached to my prepared statement.

The proposed plan of operations provides initial production rates of 0.6 million barrels per day for 6 months, 1.2 million barrels per day for approximately 12 months and then a rate of approximately 1.5 to 1.6 million barrels a day until production decline is reached. The plan provides for gas pipeline deliveries of 2.0 billion cubic feet per day as soon as gas pipeline facilities are available and a conditioning plant can be approved and constructed. The plan also contemplates selective injection of produced water into the Prudhoe Oil Pool when those volumes become significant. Although a final commitment is not made, the plan anticipates that water injection from sources outside the Pool will be initiated within 5 to 9 years after the start of oil production.

Our order No. 145 tentatively approves offtake rates of 1.5 million barrels per day of oil and 2.7 billion cubic feet per day of gas—which will yield 2.0 billion cubic feet per day for sales—subject to revision as production and reservoir data are obtained and analyzed.

Our reports studied gas withdrawal rates of 2 to 5 billion cubic feet per day—that is, gas sales of 1.5 to 3.75 billion cubic feet per day—correlated with oil production between 1.2 to 1.8 million barrels per day. We also studied oil recovery with no gas sales.

Our study shows us that the Prudhoe Bay Reservoir will be rate sensitive. By this we mean that the ultimate oil recovery from the reservoir would be affected by the net withdrawals from the reservoir and in some cases even by the rate of withdrawal. If oil, gas and water are removed without their reservoir volume being at least partially replaced, a reduction in oil recovery will result. If the reservoir voidage caused by production is replaced, then recoveries will be increased and can be maximized by the volume injected. Accordingly, we believe that fluids must be injected into the reservoir to supplement the natural recovery mechanism and that reservoir performance must be monitored closely and withdrawals controlled to achieve the maximum recovery. The level of gas sales will be determined by the volume of fluids injected.

If fluids are not returned to the reservoir our study indicates that the greater the gas sales rate, the greater is the loss in ultimate recovery. If gas sales are kept at a constant rate of 2 billion cubic feet per day there will be an increase in oil recovery with water injection. As a practical matter, it may not be possible to inject enough fluids to permit sustained rates very much in excess of 2 billion cubic feet per day. Early start of water injection will give a slightly higher oil recovery than a delay of several years, but the advantage is slight.

Once the Prudhoe Bay Reservoir is producing at a normal rate and you know we haven't been able to obtain a normal rate yet, because of station 8, it will be necessary to have at least 2 and maybe more years of production to achieve a degree of reliability in forecasting the best future method of operation for this reservoir.

Many methods of recovery theoretically show some promise to aid in the production of substantial amounts of additional oil. Many of these exotic methods, however, have not yet been proven in the field and current economics will not permit their use. Certainly with the tremendous volumes available to Prudhoe, neither the State nor the operators has to be told to consider these possibilities.

We have required that operators secure voluminous data which will help define the reservoir parameters. As is our right and our responsibility, we will exercise continuing jurisdiction over the operation of the field and will require that the method ultimately chosen by the operators be one that will achieve the greatest recoveries from the reservoir consistent with sound engineering and operating practices.

Water injection as contemplated by the operators of the Prudhoe Bay Field has proved to be one of the most reliable techniques for maximizing oil recovery in fields all over the world. This does not mean that other techniques should be ruled out even though they may be currently uneconomic or not technically feasible at this time. One such technique, the injection of CO_2, is being considered.

Our opinion is that proceeding with the approved plan will not result in any irreversible damage to oil recovery. During the first 5 years of operation, or until the approximate time that a gas line could become operational, we estimate that the decrease in reservoir pressure would amount to approximately 10 percent of the original pressure. By that time we will know if and to what degree the decline must be arrested, or if it should be reversed. If, in the future, a better method of operation is indicated we believe that the maximum recoveries still can be achieved.

My prepared statement cites an actual example in Alaska where we have followed this course and achieved excellent recovery. In short, we do not believe that a pressure decline of the magnitude we have described would have any long-term detrimental effects on ultimate oil recovery, and we certainly do not agree with Dr. Doscher that there would be losses in the magnitude of billions of barrels.

If the plan of operations as proposed by the operators is followed, with significant water injection, our work indicates that a gas sales rate of 2 billion cubic feet per day starting in approximately 5 years could be sustained over the remaining life of the field.

Let me turn to Dr. Doscher's report. It is important to distinguish between the basic engineering conclusions reached by Dr. Doscher in his report and the broader, more philosophical and policy pronouncements contained in his report. Basically, as a petroleum engineer, I find little dispute with Dr. Doscher when he describes what is still unknown and must be learned as operations continue. Our plan is to learn more and act accordingly. It is on policy matters where I cannot agree with Dr. Doscher's approaches, and my prepared statement gives a clear example of our differences.

I disagree sharply with Dr. Doscher's statement that there will be a loss of 2 to 4 billion barrels of oil if the pipeline is approved. Dr. Doscher has not substantiated this figure with any studies and has not furnished technical data on which this opinion is based. To the contrary, our own studies have been substantial and we can reach no such conclusion based on any information available to us, assuming that a water injection program of the kind planned by the operators is timely implemented to supplement reservoir pressure.

As we see it, the basic question is whether a pipeline decision should be deferred until more is learned about the performance of the Prudhoe Bay Reservoir. The State of Alaska, based on what we know today, that is, our own studies, Dr. Doscher's two draft reports, the material presented to us in our regulatory capacity, and our own professional judgment, believes there is no sound technical reason to delay, provided that the operators adopt and implement a source water injection program by the time gas sales start. If the operators do not implement a source water injection program, then gas sales will have to be limited or postponed in order to avoid jeopardizing ultimate oil recovery.

We agree that more information about the performance of the reservoir is desirable. But the State's plan allows for the gathering of that information without jeopardizing the early construction of the pipeline. It does so without substantial risk to the ultimate recovery of oil from the reservoir, and without unnecessary delay in the bringing of a major new gas supply to lower 48 users.

Mr. Chairman, we have some experts here with me and we will be glad to answer any questions.

Senator HANSEN. Senator Stevens.

Senator STEVENS. Thank you, Mr. Chairman.

Have your studies looked into the limits of the reinjection facilities that are in place now on the Prudhoe Bay field?

Mr. GILBRETH. Senator, are you referring to the gas injection facilities in the field?

Senator STEVENS. Yes.

Mr. GILBRETH. Yes.

Senator STEVENS. Will a time come, if there is no pipeline when the production of gas from the reservoir associated with the oil, would reach the limits of that reinjection facility? Do you know that?

Mr. GILBRETH. I believe our information indicates that gas production would continue to increase in the field as oil production depletes the reservoir and eventually would come to the point that it would overtax the present facilities and would require additional investment and facilities to keep reinjecting the gas. Is that what you mean?

Senator STEVENS. So a transportation mechanism for even the associated gas would be necessary, or an increased capacity for the reinjection facility would have to be constructed?

Mr. GILBRETH. Yes, that's right.

Senator STEVENS. Now, the State's position is then, I take it, that normal production practices in planning for this reservoir would require, and do require, the continuation of the procedure to authorize someone to build a pipeline?

Mr. GILBRETH. Our approval at this point is based on the need to gather additional information and, of course, the sale of the oil, and we see no reason on that, a pipeline should not be approved to take the gas sales from the field.

Senator STEVENS. We all know it is a very large field with oil and gas, but is there anything in terms of your studies, Mr. Van Poollen's studies, so far that would substantiate a conclusion that no pipeline should be built?

Mr. GILBRETH. No, Senator, we see nothing that would say that.

Senator STEVENS. And the option that we have then, according to your planning, is that gas sales can commence if production data substantiates your present position provided there is water flooding commenced at the same time?

Mr. GILBRETH. Yes. The operators have indicated they are continuing to study water flood possibilities and, of course, their studies are much like ours. They indicate essentially the same things ours do, and they know that they will have to inject fluids, and we have no reason to believe that they will not, but should they fail to do so, unless reservoir performance indicates otherwise, then we would have to restrict production.

Senator STEVENS. Is the State law designed to prevent waste?

Mr. GILBRETH. Yes.

Senator STEVENS. And your function is a conservation function?

Mr. GILBRETH. Strictly, yes.

Senator STEVENS. Just so everyone understands it, we would not allow flaring of the natural gas for the purpose of disposal?

Mr. GILBRETH. That's right. We have issued a conservation order which says the burning of gas is prohibited. There will be some obvious requirements for emergencies and things of that nature, but not as a means of disposal; no, sir.

Senator STEVENS. And in your deliberations of your Commission you don't consider economics or the State's position with regard to income, yours is a conservation conclusion?

Mr. GILBRETH. That's right. Our conservation statute is not one designed along the lines of economic waste. However, Senator, I think everyone would have to recognize that any time you enter a decision about substantial investments and things of that nature you are obviously going to consider economics somehow, but we don't consider that as a determining criteria, no.

Senator STEVENS. My point is that with regard to this conclusion that you see no reason to substantiate, and I agree with you about the philosophical comment of Dr. Doscher's report, you feel no reason to substantiate his economic position that a pipeline should not be authorized at this time?

Mr. GILBRETH. Senator, our responsibilities are strictly from the standpoint of waste and we do not give consideration to that. Could I add to that, we do believe that gas would be available and could be sold if the pipeline is built.

Senator STEVENS. I have one last question. I noticed you used fire as a method of increasing recovery. Would you educate at least one Senator on how fire could be used to increase recovery?

Mr. GILBRETH. Yes. In the western part of the United States, in California and thereabouts, there are several projects where the oil reservoir itself is actually fired. Air is pumped down, a flame front is developed and heat is used to displace or vaporize, I am not familiar with the real technical end of it, but they use this as a secondary front such as we might use water to push the oil over to a producing well.

Senator STEVENS. I will have to study that. I have never heard of that before. I don't know about the rest of the committee.

Let me ask one other thing. Dr. Doscher left me with the impression that if we produced the oil and commenced producing gas too soon that there would develop a gap between the gas cap and the oil reservoir and as a consequence the drive would not be there from the cap to bring about the full recovery from the oil in place.

Now, could you explain to me if water flooding is commenced in the beginning as you indicate, will that occur?

Mr. GILBRETH. Senator, I am not sure how Dr. Doscher explained this business right at the gas-oil contact, but let me say that in a solution drive or gas drive reservoir such as the oil phase of this reservoir would be, we believe it is necessary to lower the pressure some amount to let some gas amount of solution to establish what we call a free gas saturation in the oil zone to maximize oil recovery.

Now, I notice that Dr. Doscher says that we should do it initially and we take professional exception to that. Beyond that point if the pressure should be dropped to such a degree that you have too much gas, the gas in excess of that required for the free gas saturation will migrate up through the gas cap. Now, you would have to talk to the operators about that, but they will be putting water in essentially and the two pressures from the gas cap will be working downward. The water will be working upward and the two, if you please, squeezing the oil, and the main thing that you have to look out for in that case is that the oil does not go beyond its original gas-oil contact point. If it does that then it would saturate the dry gas capacity and you would lose recovery. Does that answer your question?

Senator STEVENS. Yes.

Let me summarize and see if you object to my summary.

I understand you to say that from a conservation point of view the State of Alaska's duly constituted agency, that is your Oil and Gas Conservation Division and Committee, the Division of Oil and Gas Conservation in the Department of Resources and the Oil and Gas Conservation Committee takes the position that a pipeline should be built and that we should proceed and approve the application that is before us. Is that going too far on your testimony?

Mr. GILBRETH. Senator, from strictly our standpoint, it would be. We say that we see no danger and harm to the ultimate recovery if the pipeline is built. We say that the gas will be there if the pipeline comes in, and we see no reason not to build it.

Senator STEVENS. Very well.

Thank you, Mr. Chairman.

Senator HANSEN. Mr. Gilbreth, the President's decision assumes that the pipeline's throughput will average 2.4 Bcf of gas per day. What do you believe the average throughput will be over the life of the field?

Mr. GILBRETH. Mr. Chairman, our studies indicate that substantial volumes of water will have to be injected as you get over 2 Bcf a day.

Now, we don't know, and I don't believe the operators know at this time, just how much water they will be able to inject. If they are able to inject enough then I think that the volumes probably could go up. However, our considered opinion, the opinion of our group at this time is that it will probably be closer to two billion a day from this particular reservoir, but we would sure want to be flexible on that because there are so many unknowns in what they will be able to do toward injection. It may change entirely or the field performance may change.

Senator HANSEN. What oil production will be necessary to sustain that rate?

Mr. GILBRETH. We estimate 1.5 to 1.6 million barrels per day.

Senator HANSEN. Will that rate require early production of gas from the gas capacity?

Mr. GILBRETH. I am sorry, Senator, but I did not understand.

Senator HANSEN. Will that rate require early production of gas from the gas cap? You spoke about the rate of oil production.

Mr. GILBRETH. Yes. That volume of gas production would be slightly in excess of the amount that would be available just from the solution gas and would require some production from the gas cap; yes.

Senator HANSEN. Dr. Doscher states on page 34 of his report that the consensus conclusion of the operators is that about 40 percent of the original oil in place may ultimately be recovered by their operating plan. What is the ultimate oil recovery percentage of oil in place, assuming that no gas is sold?

Mr. GILBRETH. Senator, do you mean our estimates or the operators' estimates?

Senator HANSEN. I would ask you what your estimate is or if you have anyone else's estimate that you might mention I would appreciate that, too, but what would yours be?

Mr. GILBRETH. From our latest runs with no gas sales we have a recovery of 39.47 percent under one set of assumptions and 40.31 percent under another set of assumptions.

Senator HANSEN. So you come out pretty nearly to the same figure that the operators come out with?

Mr. GILBRETH. Yes, that's right.

Senator HANSEN. On page 44 of his report, Dr. Doscher states that it is surprising that running and carefully interpreting a cement bond log in all wells, both injection and production, is not incorporated into the Commission's rules. Would you care to comment on that statement?

Mr. GILBRETH. Is that a cement bond log?

Senator HANSEN. A cement bond log in all wells. It is on page 44 of his report, if you would like to take a peek at it first and then discuss it.

Mr. GILBRETH. Senator, I think Dr. Doscher was critical of the Oil and Gas Conservation Committee, because it did not require water shut-off tests. The operators in the field rely quite heavily on the interpretation of the bond log. In Alaska they have not required the water shut-off test such as they have in California. The experience has been in some cases that the perforations that are necessary to make these tests fractures the cement and causes as much or more damage than the benefit out of it. Also, in Prudhoe Bay we do not have extraneous water and stringers intermingled with or in the proximity of the producing reservoir.

In California they have waters near the reservoir and it is very imperative that they get these shut off. We don't quite have the same problems at Prudhoe that they have in California. The operators could probably tell you more from the operating side on this.

Senator HANSEN. Thank you very much.

Any further questions?

Senator STEVENS. Let me ask of Dr. Van Poollen. I take it that the testimony that Mr. Gilbreth presented is based to a great extent upon your studies; is that correct?

Dr. VAN POOLLEN. That is correct.

Senator STEVENS. And are you continuing to maintain your role as a consultant for the State on this Prudhoe Bay production?

Dr. VAN POOLLEN. Yes, I am still engaged. We are maintaining a data bank of all the data that becomes available as production has started. We get the pressure reports and keep evaluating.

Senator HANSEN. I understand from what Mr. Gilbreth said that your information was furnished to everyone in connection with the FPC proceeding; is that your statement, Mr. Gilbreth?

Mr. GILBRETH. Yes, sir.

Senator STEVENS. All the information that the State has had available is available to anyone concerned with this problem so far?

Mr. GILBRETH. We have tried to make a fairly full public disclosure of everything and we testified at the FPC essentially the same way we are testifying here.

Senator STEVENS. Perhaps it is not professional to do so. Dr. Van Poollen, have you had knowledge of any other person other than Dr. Doscher who has come forward with a proposal that there should be no pipeline authorized or constructed to carry this gas?

Dr. VAN POOLLEN. I daresay Mr. Doscher and Mr. Doherty are the only professional people I am aware of.

Senator STEVENS. That's what I am talking about, professional people involved in this field.

Dr. VAN POOLLEN. Those are the only ones.

Senator STEVENS. Thank you very much.

Senator HANSEN. May I presume that none of the other witnesses at the table would care to amplify upon any of the questions I have asked Mr. Gilbreth; is that right?

Mr. GILBRETH. That's right.

Senator HANSEN. If there are no further questions, then, thank you very much, Gentlemen.

Mr. GILBRETH. Thank you, Senator.

[The prepared statement of Mr. Gilbreth follows:]

TESTIMONY OF O. K. GILBRETH, JR.
DIRECTOR, DIVISION OF OIL AND GAS CONSERVATION
DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA

BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C.
OCTOBER 25, 1977

MR. CHAIRMAN, OTHER DISTINGUISHED SENATORS, LADIES AND GENTLEMEN. MY NAME IS O.K. GILBRETH, JR. AND I AM DIRECTOR OF THE STATE OF ALASKA'S DIVISION OF OIL AND GAS CONSERVATION IN THE DEPARTMENT OF NATURAL RESOURCES AND CHAIRMAN OF ITS OIL AND GAS CONSERVATION COMMITTEE. WITH ME TODAY IS MR. HOYLE HAMILTON, OUR CHIEF PETROLEUM ENGINEER, WHO IS ALSO A MEMBER OF THE OIL AND GAS CONSERVATION COMMITTEE, DR. H. K. VAN POOLLEN, PRESIDENT OF H. K. VAN POOLLEN AND ASSOCIATES, WHO IS A CONSULTANT FOR THE STATE, AND ROBERT H. LOEFFLER, WHO HAS BEEN COUNSEL TO THE STATE IN THE GAS PIPELINE PROCEEDINGS.

MY PRIMARY RESPONSIBILITY AS DIRECTOR OF THE STATE DIVISION OF OIL AND GAS CONSERVATION IS TO REGULATE OIL AND GAS INDUSTRY OPERATIONS TO PREVENT THE PHYSICAL WASTE OF OIL AND GAS IN THE STATE AND TO PROTECT THE CORRELATIVE RIGHTS OF ALL INTERESTS IN AN OIL AND GAS FIELD. OUR GOAL IS TO REGULATE PRODUCTION IN A MANNER WHICH WILL INSURE THAT MAXIMUM RECOVERY OF HYDROCARBONS IS ACHIEVED AND PHYSICAL WASTE IS AVOIDED. AT THE OUTSET I WISH TO EMPHASIZE THAT WE DO NOT SET THE RATE OF PRODUCTION OF EITHER OIL OR NATURAL GAS SO LONG AS IT DOES NOT CREATE WASTE.

EARLIER THIS YEAR THE OPERATORS REQUESTED APPROVAL OF THE OIL AND GAS CONSERVATION COMMITTEE OF THEIR PLAN TO OPERATE THE PRUDHOE BAY FIELD. ON MAY 5, 1977, WE HELD A PUBLIC HEARING ON THIS PLAN, INCLUDING A REVIEW OF THE PROPER INITIAL RATES OF PRODUCTION. AS A RESULT OF THAT HEARING, CONSERVATION ORDER NO. 145 WAS ISSUED BY THE OIL AND GAS CONSERVATION COMMITTEE. THE ORDER CONTAINS MANY REQUIREMENTS TO SECURE DATA DURING START-UP AND THE INITIAL PRODUCTION PERIODS TO AID IN DETERMINING PROPER METHODS OF OPERATION OF THIS RESERVOIR. COPIES OF THE ORDER ARE ATTACHED TO MY PREPARED STATEMENT.

1. THE PLAN OF OPERATIONS: THE PROPOSED PLAN OF OPERATIONS PROVIDES INITIAL PRODUCTION RATES OF 0.6 MILLION BARRELS PER DAY FOR SIX MONTHS, 1.2 MILLION BARRELS PER DAY FOR APPROXIMATELY TWELVE MONTHS AND/THEN A RATE OF APPROXIMATELY 1.5 TO 1.6 MILLION BARRELS A DAY UNTIL PRODUCTION DECLINE IS REACHED. THE PLAN PROVIDES FOR GAS PIPELINE DELIVERIES OF 2.0 BCF/D AS SOON AS GAS PIPELINE FACILITIES ARE AVAILABLE AND A CONDITIONING PLANT CAN BE APPROVED AND CONSTRUCTED. THE PLAN ALSO CONTEMPLATES SELECTIVE INJECTION OF PRODUCED WATER INTO THE PRUDHOE OIL POOL WHEN THOSE VOLUMES BECOME SIGNIFICANT. ALTHOUGH A FINAL COMMITTMENT IS NOT MADE, THE PLAN ANTICIPATES THAT WATER INJECTION FROM SOURCES OUTSIDE THE POOL WILL BE INITIATED WITHIN FIVE TO NINE YEARS AFTER THE START OF OIL PRODUCTION.

Our ORDER NO. 145 TENTATIVELY APPROVES OFFTAKE RATES OF 1.5 MILLION B/D OF OIL AND 2/7 BCF/D OF GAS (WHICH WILL YIELD 2.0 BCF/D FOR SALES) SUBJECT TO REVISION AS PRODUCTION AND RESERVOIR DATA ARE OBTAINED AND ANALYZED.

2. <u>POSSIBLE RATES OF WITHDRAWAL</u>: OUR REPORTS STUDIED GAS WITHDRAWAL RATES OF TWO (2) TO FIVE (5) BILLION CUBIC FEET PER DAY (I.E., GAS SALES OF 1.5 TO 3.75 BCF/DAY), CORRELATED WITH OIL PRODUCTION BETWEEN 1.2 TO 1.8 MILLION BARRELS PER DAY. WE ALSO STUDIED OIL RECOVERY WITH NO GAS SALES.

OUR STUDY SHOWS US THAT THE PRUDHOE BAY RESERVOIR WILL BE RATE SENSITVE. BY THIS WE MEAN THAT THE ULTIMATE OIL RECOVERY FROM THE RESERVOIR WOULD BE AFFECTED BY THE NET WITHDRAWALS FROM THE RESERVOIR AND IN SOME CASES EVEN BY THE RATE OF WITHDRAWAL. IF OIL, GAS AND WATER ARE REMOVED WITHOUT THEIR RESERVOIR VOLUME BEING AT LEAST PARTIALLY REPLACED, A REDUCTION IN OIL RECOVERY WILL RESULT. IF THE RESERVOIR VOIDAGE CAUSED BY PRODUCTION IS REPLACED, THEN RECOVERIES WILL BE INCREASED AND CAN BE MAXIMIZED BY THE VOLUME INJECTED. ACCORDINGLY, WE BELIEVE THAT FLUIDS MUST BE INJECTED INTO THE RESERVOIR TO SUPPLEMENT THE NATURAL RECOVERY MECHANISM AND THAT RESERVOIR PERFORMANCE MUST BE MONITORED CLOSELY AND WITHDRAWALS CONTROLLED TO ACHIEVE THE MAXIMUM ~~OIL~~ RECOVERY. THE LEVEL OF GAS SALES WILL BE DETERMINED BY THE VOLUME OF FLUIDS INJECTED.

IF FLUIDS ARE NOT RETURNED TO THE RESERVOIR, OUR STUDY INDICATES THAT THE GREATER THE GAS SALES RATES, THE GREATER IS THE LOSS IN ULTIMATE ~~OIL~~ RECOVERY. IF GAS SALES

ARE KEPT AT A CONSTANT RATE OF TWO BILLION CUBIC FEET PER DAY, THERE WILL BE AN INCREASE IN OIL RECOVERY WITH WATER INJECTION. AS A PRACTICAL MATTER, IT MAY NOT BE POSSIBLE TO INJECT ENOUGH FLUIDS TO PERMIT SUSTAINED ~~SALES~~ RATES VERY MUCH IN EXCESS OF TWO BILLION CUBIC FEET PER DAY. EARLY START OF WATER INJECTION WILL GIVE A SLIGHTLY HIGHER OIL RECOVERY THAN A DELAY OF SEVERAL YEARS, BUT THE ADVANTAGE IS SLIGHT.

3. <u>SUCCESSFUL INJECTION PROGRAMS</u>: ONCE THE PRUDHOE BAY RESERVOIR IS PRODUCING AT A NORMAL RATE, and you know we haven't been able to obtain a normal rate yet because of Station 8, IT WILL BE NECESSARY TO HAVE AT LEAST TWO AND MAYBE MORE YEARS OF PRODUCTION TO ACHIEVE A DEGREE OF RELIABILITY IN FORECASTING THE BEST FUTURE METHOD OF OPERATION FOR THIS RESERVOIR.

MANY METHODS OF RECOVERY THEORETICALLY SHOW SOME PROMISE TO AID IN THE PRODUCTION OF SUBSTANTIAL AMOUNTS OF ADDITIONAL OIL. MANY OF THESE EXOTIC METHODS HOWEVER HAVE NOT YET BEEN PROVEN IN THE FIELD AND CURRENT ECONOMICS WILL NOT PERMIT THEIR USE. CERTAINLY WITH THE TREMENDOUS VOLUMES AVAILABLE AT PRUDHOE, NEITHER THE STATE NOR THE OPERATORS HAVE TO BE TOLD TO CONSIDER THESE POSSIBLITIES.

WE HAVE REQUIRED THAT OPERATORS SECURE VOLUMINOUS DATA WHICH WILL HELP DEFINE THE RESERVOIR PARAMETERS. AS IS OUR RIGHT AND OUR RESPONSIBILITY, WE WILL EXERCISE CONTINUING JURISDICTION OVER THE OPERATION OF THE FIELD AND WILL REQUIRE THAT THE METHOD ULTIMATELY CHOSEN BY THE OPERATORS BE ONE THAT WILL ACHIEVE THE GREATEST RECOVERIES FROM THE RESERVOIR

CONSISTENT WITH SOUND ENGINEERING AND OPERATING PRACTICES.

4. MOST APPROPRIATE PRODUCING PLAN: WATER INJECTION AS CONTEMPLATED BY THE OPERATORS OF THE PRUDHOE BAY FIELD HAS PROVED TO BE ONE OF THE MOST RELIABLE TECHNIQUES FOR MAXIMIZING OIL RECOVERY IN FIELDS ALL OVER THE WORLD. THIS DOES NOT MEAN THAT OTHER TECHNIQUES SHOULD BE RULED OUT EVEN THOUGH THEY MAY BE CURRENTLY UNECONOMIC OR NOT TECHNICALLY FEASIBLE AT THIS TIME. ONE SUCH TECHNIQUE, THE INJECTION OF CO_2, IS BEING CONSIDERED.

OUR OPINION IS THAT PROCEEDING WITH THE APPROVED PLAN WILL NOT RESULT IN ANY IRREVERSIBLE DAMAGE TO OIL RECOVERY. DURING THE FIRST FIVE YEARS OF OPERATION, OR UNTIL THE APPROXIMATE TIME THAT A GAS LINE COULD BECOME OPERATIONAL, WE ESTIMATE THAT THE DECREASE IN RESERVOIR PRESSURE WOULD AMOUNT TO APPROXIMATELY TEN PERCENT OF THE ORIGINAL PRESSURE. BY THAT TIME WE WILL KNOW IF AND TO WHAT DEGREE THE DECLINE MUST BE ARRESTED, OR IF IT SHOULD BE REVERSED. IF, IN THE FUTURE, A BETTER METHOD OF OPERATION IS INDICATED, WE BELIEVE THAT THE MAXIMUM RECOVERIES STILL CAN BE ACHIEVED. MY PREPARED STATEMENT CITES AN ACTUAL EXAMPLE IN ALASKA WHERE WE HAVE FOLLOWED THIS COURSE AND ACHIEVED EXCELLENT RECOVERY. IN SHORT, WE DO NOT BELIEVE THAT A PRESSURE DECLINE OF THE MAGNITUDE WE HAVE DESCRIBED WOULD HAVE ANY LONG TERM DETRIMENTAL EFFECTS ON ULTIMATE OIL RECOVERY, AND WE CERTAINLY DO NOT AGREE WITH MR. DOSCHER THAT THERE WOULD BE LOSSES IN THE MAGNITUDE OF BILLIONS OF BARRELS.

5. <u>Likely Rate of Gas Production</u>: If the plan of operations as proposed by the operators is followed, with significant water injection, our work indicates that a gas sales rate of two Bcf/D starting in approximately five years could be sustained over the remaining life of the field.

****

Let me turn to Mr. Doscher's report. It is important to distinguish between the basic engineering conclusions reached by Mr. Doscher in his report and the broader, more philosophical and policy pronouncements contained in his report. Basically, as a petroleum engineer, I find little dispute with Mr. Doscher when he describes what is still unknown and must be learned as operations continue. Our plan is to learn more and act accordingly. It is on policy matters where I cannot agree with Mr. Doscher's approaches, and my prepared statement gives a clear example of our differences.

I disagree sharply with Mr. Doscher's statement that there will be a loss of two to four billion barrels of oil if the pipeline is approved. Mr. Doscher has not substantiated this figure with any studies and has not furnished technical data on which this opinion is based. To the contrary, our own studies have been substantial and we can reach no such conclusion based on any information available to us, assuming that a water injection program of the kind planned by the operators is timely implemented to supplement reservoir pressure.

AS WE SEE IT, THE BASIC QUESTION IS WHETHER A PIPELINE DECISION SHOULD BE DEFERRED UNTIL MORE IS LEARNED ABOUT THE PERFORMANCE OF THE PRUDHOE BAY RESERVOIR. THE STATE OF ALASKA, BASED ON WHAT WE KNOW TODAY -- I.E., OUR OWN STUDIES, MR. DOSCHER'S TWO DRAFT REPORTS, THE MATERIAL PRESENTED TO US IN OUR REGULATORY CAPACITY, AND OUR OWN PROFESSIONAL JUDGMENT -- BELIEVES THERE IS NO SOUND TECHNICAL REASON TO DELAY, PROVIDED THAT THE OPERATORS ADOPT AND IMPLEMENT A SOURCE WATER INJECTION PROGRAM BY THE TIME GAS SALES START. IF THE OPERATORS DO NOT IMPLEMENT A SOURCE WATER INJECTION PROGRAM, THEN GAS SALES WILL HAVE TO BE LIMITED OR POSTPONED IN ORDER TO AVOID JEOPARDIZING ULTIMATE OIL RECOVERY.

WE AGREE THAT MORE INFORMATION ABOUT THE PERFORMANCE OF THE RESERVOIR IS DESIRABLE. BUT THE STATE'S PLAN ALLOWS FOR THE GATHERING OF THAT INFORMATION WITHOUT JEOPARDIZING THE EARLY CONSTRUCTION OF THE PIPELINE. IT DOES SO WITHOUT SUBSTANTIAL RISK TO THE ULTIMATE RECOVERY OF OIL FROM THE RESERVOIR, AND WITHOUT UNNECESSARY DELAY IN THE BRINGING OF A MAJOR NEW GAS SUPPLY TO LOWER FORTY-EIGHT USERS.

Senator HANSEN. Our next witness, from Atlantic Richfield, is Dr. Howard A. Koch, manager of the engineering department, North American Producing Division, Atlantic Richfield, Dallas, Tex.

Dr. Koch, we would be pleased to have your testimony, sir.

STATEMENT OF DR. HOWARD A. KOCH, MANAGER, ENGINEERING DEPARTMENT, NORTH AMERICAN PRODUCING DIVISION, ATLANTIC RICHFIELD, DALLAS, TEX.

Dr. KOCH. My name is Howard Koch. I am a graduate of Northwestern University with a Ph. D. in chemical engineering. Since 1949, I have been employed by the Atlantic Richfield Co. I am currently manager of engineering for Atlantic Richfield Co's. North American Producing Division. For the past 8 years I have been heavily involved in Atlantic Richfield's efforts to explore and develop the Prudhoe Bay Field in Alaska, and I have been responsible for and directed many studies of the reservoir and its performance.

We have been asked to come here to answer certain questions and clarify concepts relative to the operation of the Prudhoe Bay Sadlerochit Reservoir. For that purpose I have a detailed statement which I would like to submit to the committee for the record.

I now wish to summarize my written testimony.

In this discussion I will present our estimate of ultimate recovery of oil in place and the effect of gas sales timing on hydrocarbon recovery.

I will also make a few comments on the possibility of applying tertiary recovery to the Sadlerochit Reservoir. The effect of tertiary recovery will also be discussed.

We have studied many alternative reservoir development plans using mathematical models. We have a high degree of confidence in the use of these models, particularly when they are used to compare different assumptions of reservoir management. They can be used to define key variables such as timing of gas sales, rate of gas sales, and timing, volume, and distribution of injected water. Through this sophisticated reservoir engineering tool we have calculated the recovery of 40 percent of the original oil in place.

The Atlantic Richfield plan will achieve 40 percent of recovery and involve the early sale of 2 billion cubic feet of gas a day, 5 years after start of oil production, and also involve the injection of water at about the same time as gas sales, the 5th through the 7th year after start of oil production.

There is nothing extraordinary about a 40 percent recovery factor and we will continue to search for ways to increase that percentage.

Comments have been made that low residual oil saturations in the range of 0 to 15 percent in the gravity drainage areas of the reservoir are required to achieve 40 percent recovery. Our studies do not support this contention. Our results exhibit residual oil saturations varying from 20 to 30 percent, a normal result from short-term drainage and high return reservoirs. We feel confident that we can achieve a recovery of at least 40 percent of the oil in place by selling 2 billion cubic feet of oil a day as soon as the gas line is available.

Using the same mathematical models, we look at the effect of gas sales timing on recovery. We look at selling gas after the 5th and 15th year of production. The results of our studies indicate that later gas sales could increase crude oil recovery in the order of 1 percent of the original oil in place, if we assume that no additional measures have been taken to offset the potential loss. By way of comparison this is less than one-twentieth of the loss estimated or mentioned by Dr. Doscher.

In actual field operations, measures can be taken to offset the potential loss.

In addition to overlooking the flexible nature of our operating plan which will be adjusted to maximize recoveries, Dr. Doscher also disregarded the injurious effect on natural gas liquid recovery by delaying gas sales from this reservoir.

The most efficient way of getting natural gas liquids from Prudhoe is by blending them into the crude stream.

About 40,000 barrels a day of natural gas liquids would be produced from a gas conditioning plant required by the proposed pipeline system for shipment of the gas. Most of these liquids could be blended into the crude stream without exceeding vapor pressure limitations as long as the oil rates stay on the order of 1.5 million barrels a day. If we waited until the 15th year to sell gas we could not transport as much of these liquids and there would be a loss on recovery.

The reserve of natural gas liquids is estimated to be 400 million barrels. A 10 year delay might reduce delivery. Reserves due to gas sales certainly offsets, in part, the rather small potential gain in crude oil recovery associated with the delay.

The operating plan approved by the State of Alaska includes the early sale of natural gas, as you heard earlier. Tertiary recovery has been mentioned as a possibility for increasing the yield from the Sadlerochit Reservoir.

Because of the logistics problem and tremendous costs associated with transporting materials it appears that we will have to use injection fluids already present at Prudhoe for tertiary recovery. We have conducted laboratory studies with the possible use of carbon dioxide as a means of increasing oil recovery. The gas at Prudhoe contains 12 percent CO_2 and would provide enough material to treat only a small portion of the reservoir. These studies indicated that the pressure is considerably in excess of the initial reservoir pressure. This means that recoveries using carbon dioxide would not be as high as they would be under other conditions. However, there may be some promise in using CO_2 in a restricted portion of the reservoir.

The key point here is that as soon as gas sales commence, carbon dioxide will be available for injection at a time when reservoir pressure is higher than would be the case for deferred gas sales. Recoveries from the use of CO_2 would not be large, because of the limited volume available, but they will be higher if the higher reservoir pressure available in the early years of field production is available.

We have also looked at the enriching of carbon dioxide with NGL's to lower admissibility pressure. Laboratory studies are continuing by Atlantic Richfield to see how we might use carbon dioxide in an optimum manner.

As a result of our studies and in accordance with the development plan approved by the State of Alaska, we estimate that daily gas pipeline deliveries of approximately 2 Bcf/d can be sustained for about 25 years.

For your review, we have submitted with our written testimony a copy of the Prudhoe Bay Plan of Production which was produced jointly by representatives of Atlantic Richfield Co., BP, Alaska, Inc., Exxon USA, and Standard Oil Company of Ohio. It contains a summary of technical work done over the last several years by the owners.

I appreciate having an opportunity to appear before your committee today. Thank you.

Senator HANSEN. Dr. Koch, we will submit in writing a number of questions to you and to the other representatives of the oil producing companies. We would appreciate your responses in writing in order that you could have time to study the questions and prepare your answers for including in the record. I just make that announcement as those who succeed you appear they too will receive copies of these series of questions. [See appendix.]

I do have some other questions I would like to ask orally.

The October 1976 report, "Technical Consideration of the Prudhoe Bay Unit Operating Plan" which your company and BP Alaska submitted to the State of Alaska, states that preliminary estimates made a few years ago indicate that the gas conditioning plant will require 4 to 6 years for design, fabrication, and construction and will cost approximately $1 billion in 1975 dollars. Do you have more recent estimates of the lead time and the costs?

Dr. KOCH. We are in the process now of obtaining that information, so to answer your question we do not have it now but we should in a few months.

SENATOR HANSEN. Does your company intend to assist in the payment of the costs for the gas conditioning plant?

Dr. KOCH. I will have to defer to my good friend to my right here.

Senator HANSEN. Would you identify yourself?

Mr. DICKERSON. My name is Kenneth Dickerson of Atlantic Richfield Co. We have testified before that we believe the construction of the conditioning plant is a function of the gas transmission system since the conditioning of this gas is unique, because of the requirements of the pipelines. We have indicated that we believe that is a transportation process and not the responsibility of the producers.

On the other hand, the Atlantic Richfield Co. has stated that, under the proper circumstances, we would be willing to consider joining with others in financing the cost of this facility. Obviously many of those conditions have not been clarified.

Senator HANSEN. Dr. Koch, does your company believe that the cost of the gas conditioning plant should be borne by the gas pipeline project? Maybe you have anticipated that question?

Dr. KOCH. Yes.

Senator HANSEN. Does your company intend to assist in financing the pipeline project by providing debt guarantees?

Mr. DICKERSON. Again, Senator, we have advised the administration by letter and Dr. Schlesinger, and the Committees in the House, that we do not intend to participate in debt financing for a variety of reasons, one being the limitation imposed on any type of management involvement by our company and this results in an opinion by the Department of Justice which initially concluded that we should not be able to participate in any way in debt financing. Secondly, the debt financing as proposed and suggested in the President's recommendation to the Congress is so broadly written that there would be no way of determining what the obligation of a producing company might be. With such an open-ended obligation, it would be in direct violation of our indentured and our preferred stock.

Senator HANSEN. Does your company believe that it may be equitable to have a gas pipeline project pay for all or part of the water flood cost?

Dr. KOCH. Would you repeat that, please, sir?

Senator HANSEN. Does your company believe that it may be equitable to have the gas pipeline project pay for part or all of the water flood costs?

Dr. KOCH. Well, frankly, I never thought of it one way or the other. In the engineering sense I have only been concerned about what is the total cost. I have really not gone into the financing aspect of it.

Senator HANSEN. Do you care, upon reflection and consultation, to add any supplemental statement you might include that isn't in the record?

Is your company currently negotiating with any companies for the sale of your natural gas of Prudhoe Bay?

Mr. DICKERSON. Senator, as you recall, Atlantic Richfield had entered into preliminary agreements about 2 years ago for the disposition of Prudhoe Bay gas. Thereafter, the FPC modified rules which had been in effect for several years terminating in effect the preliminary agreements which we had. Since that time we have asked the FPC and the administration to identify the regulatory rules applicable to Alaska which is excluded from the current regulatory scheme of the Federal Power Commission or the FERC. Those rules have not been extended to Alaska. There is no current price example established for Alaska yet and under those circumstances we feel that it would be imprudent and impossible to negotiate contracts and, therefore, we have not.

Senator HANSEN. Does your company believe that the gas pipeline project can be privately financed?

Mr. DICKERSON. In our testimony before Congressman Dingell's committee we expressed rather serious reservations about the possibility of private financing. As we indicated at that time there are a number of difficulties associated with construction of this line, not the least of which is the fact that there are several government bodies involved. Some rules have not been clarified at this point. We suggest that the financing can be done privately. We hope that it can be done privately. What we suggested to the House Committee was that there be an effort made to finance the line and that the sponsors of the line be required to report back to the Congress within a reasonable period of time to indicate whether or not private financing is a possibility. Certainly, we think that they should contact all of the major financing institutions at an early date.

Our theory is that if they wait an unnecessarily long period of time, it would delay this project and initial gas sales which we understand are contemplated from Canada, and for that reason we recommended that there be a 6-month period of time for financing and if they are unable to do so at that time we will ask Congress to discuss alternative means of financing. But we certainly support private financing.

Senator METCALF. I have no questions, Mr. Chairman.

Senator HANSEN. Senator Stevens.

Senator STEVENS. Dr. Koch, Dr. Doscher's report on page 51 makes this statement: "In the absence of future discoveries of crude oil which can be transported by the present crude line from the North Slope to Valdez, throughput will begin to decrease precipitously within 8 years and within 15 years less than 500,000 barrels a day." That is repeated several times throughout this report.

Now, do your studies substantiate that production will fall off to 500,000 or less barrels a day at the end of 15 years on the oil?

Dr. KOCH. We do indicate that a sharp decline after about 9 years, give or take a little bit, of production. But, Senator, this is not too unusual because after 9 or 10 years of production we would have produced a large percentage of our ultimate reserve. I think the number comes to mind of by half by the time the decline starts. Ideally, Senator, what I would like to do is produce at a constant rate to the last drop. You would have the lowest operating cost and the best economics for both the company and others.

Senator STEVENS. Well, his thesis, as I understand it, is that if there is gas that is available for sale it should start at the oil pipeline and should use an alternate transportation mechanism for the oil and the gas. Have you examined that option of delayed production of gas for sale until the oil production declines and using the same pipeline to transport the gas as used for the oil?

Dr. KOCH. We haven't studied it in detail. We have certainly talked about it a number of times. There are some physical problems with that type of situation. One of them, if you are still producing a sizeable quantity of oil, 400,000 or 500,000 barrels a day, it is difficult to recompress at various stages using the same line. From a technical standpoint I think it could be done and I think the money involved would be very large to get the system to work properly.

Senator STEVENS. I have been for a gas pipeline but I am also intrigued with some of the Doscher comments, and I understand the position of our State. He postulates that the potential of alternate utilization of the gas for other purposes on site, such as petrochemical development plus the transportation of the gas that has to be exported in a two-phase flow of oil and gas in a crude oil line would save us the total cost of the gas line, and that is estimated to $15 billion as the cost of converting that oil line, so it could be two-phased when considered as far as his type of investment is concerned?

Dr. KOCH. Not enough detail to answer that specific question, whether the cost of operating the line to handle two-phase flow would be equivalent to the $15 billion that he talked about. I can't answer. I doubt if it would be that much, however. One would be holding gas off the market, if you will, for a number of years in order to accomplish that.

Senator STEVENS. Well, if the throughput begins to increase precipitously within 8 years, we are already producing now, that's only 7½ years away, but as I understand it the gas pipeline is at least 8 years away. What I want to know is whether any of the producers has taken into consideration the effect of delay and the effects of inflation on cost and actually studied whether or not it is in the best interest of the producers and the State. We have a commonality of interest with you to review the decision that there should be a gas pipeline.

Dr. KOCH. I wouldn't resist the suggestion to review it at all. I am agreeing with you that it should be looked at. We have not looked at it in detail. We will, obviously.

Senator STEVENS. Well, we are faced with a question of whether to approve this recommendation for a gas pipeline.

Let me ask you this, I am not trying to be too antagonistic, but I am slightly disturbed if the producers had known about this concept of Dr. Doscher's and that we are faced with it at the last minute. When did you know about Dr. Doscher's comments and his position with regard to the concept of using a two-phase flow for the gas pipeline?

Dr. KOCH. When I read the transcript of the hearings that were held here in the last few weeks.

Senator HANSEN. Well, unfortunately that's when we knew about it, too. Could you give us any kind of a time frame within which a decision might be made by the producing companies as to whether this concept could and would be reviewed?

Dr. KOCH. Yes, I think I can. I don't believe it would take more than a few weeks to look at it and test the economics and so forth on that idea. I say a few weeks, 3 or 4.

Senator STEVENS. Now, it is my understanding that my staff and I were told that it was going to take 5 years to build a gas conditioning plant. Are you familiar with that plan?

Dr. KOCH. I heard four to six. I think, a little earlier. We are restudying both the scheduling and the ultimate cost of a gas conditioning plant at the present time. So until the study is complete I can't comment. However, I do think we could do better than five, maybe four, but I think we ought to wait until the study is complete.

Senator STEVENS. Very frankly the thing that disturbs me is the question of time. Each hearing we have gotten into a more prolonged period for the ultimate development of the facilities that would be necessary to transport the gas. There must be a gas conditioning plant and there must be a pipeline in place under the theory proceeded under now. A I understand it the goal to get the gas pipeline in place is 1983 and it would be approximately the same time for the gas conditioning plant assuming that the plant is not built until the purchasers are identified.

Do you know of any more optimistic time frame than that for the transportation of gas?

Dr. KOCH. No, that's about the same ones I am familiar with.

Mr. DICKERSON. Senator, one additional comment. As you may recall, the conditioning plant is something directly related to the type of pipeline that is ultimately constructed, relating to temperatures, pressures, dewpoint, all of these factors will determine the kind of plant which is to be built. Setting aside the question of who is to finance, and this has been the subject of lengthy discussion, this plant cannot be designed by whomever is going to own it, whether it is producers which we contend it should not be, or the pipeline companies, until it has been determined the pressure of the pipeline and size, dewpoint and temperature.

While we, for example, might wish to go forward with some kind of evaluation as to what is to be constructed ultimately, it is quite difficult to do so until the FERC and the sponsors decide what they are going to build. The financing question can be resolved somewhat after that, but I don't believe anybody at this time can determine the construction period until I know what you are building.

Senator STEVENS. Well, as a layman I never could understand why you didn't build the plant to take the liquid out and put it in the pipeline. You are taking the gas out and putting it back in and taking it out the second time. Why isn't it more efficient to take the gas liquids out in the first instance?

Dr. KOCH. That costs $1 billion to get a billion gallons a day and I submit that's not economic.

Senator STEVENS. If your basic assumption is that there is going to be a gas pipeline you are pumping the gas twice and by failing to go ahead with the gas conditioning plant you are prolonging the time frame to the point that Dr. Doscher's recommendations have some substance, namely if that gas is not available for transportation by pipeline until the end of the 8 years when the oil production falls off why build the gas pipeline?

Dr. KOCH. That's certainly a case that we will be looking at.

Senator STEVENS. Incidentally, just one last question. We were told the other day that the gas conditioning plant would not take the butanes, propanes and ethanes out and it would be necessary to build another gas conditioning plant somewhere further down the line. Is that correct? Is that in your plan?

Dr. KOCH. I am sorry, I didn't quite understand. You said that there would be two conditioning plants. As Mr. Dickerson mentioned earlier the first conditioning or the conditioning, I should say, on the Slope is to meet pipeline specifications, that's the purpose of it, so the gas can go down the pipeline. It will still have 1,130, or some odd Btu's. So somewhere down on the south 48 they may decide that they would like to condition that gas further and get the Btu's down to 1,000 Btu's per cubic foot. That would be drying it further but that's beyond the purview of my particular studies. It is possible.

Senator STEVENS. Very well.

Again, Mr. Chairman, I am still in support of a pipeline but I am starting to get some serious questions in my mind and wonder if the rest of the Senate is going to have them by the time we take this bill out to the floor, and I think we ought to have some answers before we get there.

Thank you very much, Dr. Koch.

Dr. KOCH. You are welcome.

Senator HANSEN. Thank you, Senator Stevens. Thank you Dr. Koch.

[The prepared statement of Dr. Koch follows:]

STATEMENT OF ATLANTIC RICHFIELD COMPANY

BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES, UNITED STATES SENATE

OCTOBER 25, 1977

My name is Howard Koch. I am a graduate of Northwestern University with a PhD. in chemical engineering. Since 1949 I have been employed by Atlantic Richfield Company and am currently Manager of Engineering of Atlantic Richfield Company's North American Producing Division. For the past eight years I have been heavily involved in Atlantic Richfield's efforts to explore and develop the Prudhoe Bay Field in Alaska and I have been responsible for and directed many studies of the reservoir and its performance.

As you know, Atlantic Richfield operates the eastern one-half of the Prudhoe Bay Field and BP Alaska, Inc., operates the western portion. As owner of approximately 1/5 of the crude oil and approximately 1/3 of the natural gas in the field, Atlantic Richfield is deeply concerned with maximizing ultimate recovery of all hydrocarbons producible from the field. We believe that all of the produced substances are extremely valuable and should be made available to U. S. consumers at the earliest practicable date consistent with good reservoir management. We further believe that our development plan which has been approved by the State of Alaska satisfies all of these prerequisites.

The Prudhoe Bay Field, discovered in 1968, is by far the largest oil and gas field producing in the United States.

Its recoverable hydrocarbon reserves have an energy equivalent of over 80 quadrillion BTU's. Because of the significance of this vast energy resource, the major working interest owners, the Alaska Division of Oil and Gas Conservation and others, have independently evaluated plans for production of this field.

Many reports have been written concerning the optimum development of the Prudhoe Bay Field. In October 1976, the working interest owners prepared and submitted a report entitled "Technical Considerations--Prudhoe Bay Unit Operating Plan, North Slope Alaska" to Mr. O. K. Gilbreth, Director, Division of Energy and Minerals Management--State of Alaska. 1/ This report contained a summary of the work conducted by Atlantic Richfield as well as BP Alaska, Inc.; Exxon, U.S.A.; and The Standard Oil Company (Ohio). The major conclusions in this report concerning plans for production of the Prudhoe Bay Field are consistent with the conclusions contained in H. K. Van Poollen studies conducted for the State of Alaska. Specifically, these reports concluded that the optimum producing plan for the Prudhoe Bay Field includes the early sale of natural gas.

We wish to outline for you today the major objectives we strived to achieve in developing our plans for producing the

1/ See Exhibit A - "Technical Considerations, Prudhoe Bay Unit Operating Plan - North Slope Alaska".

Prudhoe Bay Field and to comment upon Dr. Doscher's remarks before this committee. One of our key objectives is the development of both the oil and gas reserves as efficiently as possible.

The proved hydrocarbon reserves at Prudhoe Bay represent approximately 30% of the Nation's liquid reserves and 12% of the Nation's natural gas reserves. For this reason, another prime objective in the development of our operating plan for the field included conservation of the total energy resource. Therefore, as required by State Law and as directed by our own management, we plan to produce the reservoir in a manner consistent with sound engineering practices designed to achieve maximum economic recovery of oil and gas and to prevent waste.

State Law requires that the proposed plan of production protects correlative rights; i.e., that each working interest owner is afforded an opportunity to produce, without waste, its just and equitable share of the oil and gas. The working interest owners and the State have agreed that the production plan, including the early sale of gas from the field, will provide for this protection.

Finally, our plans for producing the field should be as flexible as possible so that we can react promptly to anomalies in reservoir behavior to assure efficient recovery of oil and gas from the field.

To achieve these aforementioned basic objectives, i.e., timely development, conservation of resources, protection of correlative rights and flexibility to adapt to observed performance, we have combined our reservoir studies with engineering judgement gained through worldwide experience, to formulate our present reservoir management plan.

We developed the production plan by studying the effects of alternative development plans, through the use of mathematical reservoir models. Through the use of these sophisticated reservoir engineering tools, it is possible to study various aspects of field performance including such things as oil and gas production rates, gas and water injection rates, infill drilling, tubular equipment selection, artificial lift alternatives, gathering system pressures and reservoir description. The evaluation of reservoir description and its effect on our operating plan decisions is perhaps the most powerful advantage to using these mathematical models.

A question has been raised concerning the reliability of a reservoir model in the absence of production history. Although it is true that the availability of production history can provide a useful check of a study and a basis for modification, Atlantic Richfield has a high degree of confidence in its reservoir model predictions, especially when these models are used to compare different methods of reservoir management. Two reasons exist for this high degree of confidence. First, because of the long period of time between discovery and commencement of deliveries to TAPS, the operators have drilled wells over a rather large area of the reservoir. As a result of this, we have secured unusually detailed reservoir descriptive information and have compiled specialized studies including geologic history, rock data, fluid sample data and log data. These data were used to determine in-place volumes of oil and gas as well as for the determination of reservoir performance. Rarely is such quality and quantity of reservoir data available prior to any sustained production from a field. A portion of these data pertaining to individual well performance, has been verified through the use of individual well models in matching actual drawdown and buildup tests performed in the field. Although a limited amount of data under sustained production is now available, actual well performance matches our predictions.

Second, confidence in our reservoir model predictions has been gained through sensitivity testing. In sensitivity testing our objective was to identify those reservoir parameters having the greatest effect on ultimate recovery and define those parameters to the fullest extent possible. Our application of this approach and the subsequent followup work, both field and laboratory, has given us an extra degree of confidence in our forecast of Prudhoe Bay performance. Although some adjustments may be made in the model as production history is accumulated, our current forecasts are adequate to demonstrate the viability of our current operating plan.

I would like to briefly outline the major elements as well as explain the expected general performance of the field under our operating plan. This plan anticipates crude oil deliveries to TAPS of 1.5 million BOPD when pipeline capacity is available.

Injection facilities were installed for the reinjection of all produced gas in excess of that needed for field and pipeline fuel to conserve gas for future sales and to comply with the State of Alaska's nonflaring order. Current gas injection capacity of 1.2 billion cubic feet per day (BCFD) will be expanded to handle up to 2.0 BCFD by mid-1979.

Gas pipeline deliveries of 2.0 BCFD can be commenced as soon as a gas transmission system can be completed. Testimony before the Congress concludes that the most likely date that gas can be delivered into a pipeline system will be 1983. Our reservoir model studies have shown us that the field can be managed so that gas deliveries at that time will be non-injurious to the reservoir.

Current water production volumes are very small and are being injected into the shallower Tertiary/Cretaceous sands. When this produced volume becomes significant it will be reinjected into the portions of the Sadlerochit reservoir exhibiting low natural depletion recovery. It is anticipated that this operation will commence in 1981. Through optimum redistribution of the produced water, the benefits of the natural water influx will be maximized. We plan to supplement this produced water injection with additional volumes of water from an outside source when our current estimates of recovery benefits can be verified along with the substantiation of its economic viability.

Some of the reservoir performance characteristics which were repeatedly revealed in our model studies are:

1. A small volume of natural water influx. This anticipated volume will be substantially less than that required to fully maintain reservoir pressure. Poor aquifer response is expected because we have noticed a degradation of rock properties in the aquifer.
2. Although all the natural recovery mechanisms (gravity drainage, gas cap expansion, solution gas drive and natural water influx) will be operating, the gravity drainage mechanism will be dominant and lead to

efficient fieldwide recoveries.

3. The expansion of the gas cap is dramatic in the first several years of production. It not only moves in a vertical direction at the rate of about 25 feet per year, but it also moves horizontally along the top of the formation and underneath continuous shale barriers. This horizontal movement can occur over several miles and is a result of the rather low formation dip (1 to 2 degrees). This gas cap expansion in the early years will expose a large percentage of the wells to a free gas saturation.
4. The expansion of the gas cap will result in a large volume of gas cap gas being produced through the oil wells. This means that a rather large volume of gas will be reinjected in the absence of a gas pipeline.
5. The advance of the gas-oil contact, to a large degree, controls the onset of oil production decline. Since the expansion of the gas cap is largely a function of oil zone withdrawals, we have seen in

our models that the timing of anticipated gas sales has little or no impact on the point of oil decline.

6. We do not anticipate any oil migration into the original gas cap as a result of gas cap shrinkage because of the substantial voidage accumulated by the oil rim prior to gas sales, and because of the smaller cap voidage rate in the early years of gas sales.

I would now like to specifically discuss some of our reservoir model results and how they have led to our plan of operation for the Prudhoe Bay Field. Although a considerable effort has been expended over the last eight years by my company in determining various aspects of producing the field, I would like to emphasize only two areas of interest: gas sales and source water injection.

There are two major considerations when evaluating the timing of gas sales. Those are:

Is there a market for the gas now? (The Prudhoe Bay natural gas and gas liquids reserves (to be discussed in detail hereafter) amount to 26 trillion cubic feet and 400 million barrels respectively, the energy equivalent of approximately 4.7 billion barrels of crude oil, or over 1/2 of the crude oil reserves.)

In the opinion of experts appearing before the Congress there is no doubt that there is a market for this gas now, and delivery should commence as soon as a gas pipeline system is completed.

The next consideration is: What effect does the timing of gas sales have on ultimate recovery of hydrocarbons? (If you will remember, conservation was one of our major objectives in determining the optimum plan of operation for the field.)

In evaluating the effects of gas sales timing on crude oil reserves, reservoir model studies were made with different timing assumptions for the commencement of gas sales. From the studies, we found that the ultimate crude oil recovery could increase in the order of 1% of the original oil-in-place if gas sales were deferred from 1982 to 1992 and if no additional measures were taken to offset the loss. This finding represents the maximum impact that gas sales timing could have on ultimate crude oil recovery. To focus on this potential 1% loss only would be a mistake, for it would disregard other hydrocarbons in the reservoir that are as valuable as oil.

To fully evaluate the effects of early gas sales, we must also consider natural gas liquid recovery. These natural gas liquids will be removed in the conditioning of the field gas to meet gas pipeline specifications. We estimate that approximately 400 million barrels of these natural gas liquids can be removed. The volume of these liquids that can be delivered to the consumer through TAPS, however, is dependent upon a number of variables including oil throughput rate. If gas is sold early in the life of the field while the oil pipeline is at capacity, more of these liquids can be transported with the oil. If, on the other hand, gas sales are delayed until a point of low oil throughput rate, some of these liquids will be reinjected into the reservoir and probably not recovered.

Permit me to summarize the conservation aspects of gas sales timing. Potential adverse effects on crude oil recovery amount to approximately 1% of the original oil-in-place if gas sales timing is varied from 1982 to 1992. By way of comparison, this is less than 1/20 of the loss estimated by Dr. Doscher. We believe that such a potential loss in recovery would be offset in actual field operations by varying the number and location of producing wells, the areal distribution of oil offtake rates and the locations and volumes of water injection, and further be offset by the shipment of natural gas liquids with crude oil in TAPS during the early stage of field production. We estimate that the loss in natural gas liquids would amount to approximately 125 million barrels for a delay in sales from 1982 to 1992, a loss not considered by Dr. Doscher in his review. With a three year deferral of gas sales as proposed by Dr. Doscher the loss in natural gas liquids could be about 45 million barrels.

Potential reduction in oil recovery from any reservoir due to the early sale of gas has been a subject of considerable discussions in the field of petroleum reservoir engineering. There is one general conclusion that can be drawn concerning this early gas sale: i.e., the withdrawal of associated gas can cause a reduction in oil recovery if nothing is done to replace the energy. Beyond that, however, no other conclusions should be drawn. This potential reduction can only be estimated through a thorough analysis of the drive mechanisms that are present in a particular reservoir. One excellent method in accomplishing this is through the use of mathematical reservoir models.

In our analysis, the effect of gas sales at Prudhoe Bay was small for the following reasons:

1. The dominant recovery mechanism is gravity drainage. Gas in such a drive mechanism does not act as an expulsive force to drive the oil out of the pore spaces. Instead, the gas merely expands to fill the empty pore spaces as the oil drains out.
2. Prudhoe Bay crude is both a low shrinkage and relatively low viscosity oil.
3. Even with the earliest anticipated gas sales date (1983) approximately 30% of the ultimate oil reserves will have been recovered.
4. The normal dangers of gas cap shrinkage will not be a problem at Prudhoe Bay, due to the expansion of the gas cap in the early years of production combined with a rather modest cap voidage rate immediately after sales commence.

It has been stated to this Committee that the producers have calculated small gas sale effects due to low residual oil saturations left behind the invading gas cap. In our studies, these residual saturations range from 20 to 30%. We submit not only that such saturations are reasonable, but we also believe that an analysis of gas sale effects is not strongly dependent upon these saturations.

Turning now to water injection for Prudhoe Bay, a much more complex problem. Gas sales effects are mainly related to pressure-volume relationships and can be easily evaluated with fluid properties and in-place volume considerations. An optimized waterflood, on the other hand, will require more study including the location of water injection wells and injection rates. These optimum volumes and locations can best be determined through the analysis of actual field production history.

Our current estimate of incremental waterflood recovery is about 4% of the original oil-in-place. This incremental recovery benefit was forecasted with an injection program assumed to commence in 1984 with daily injection of 2 million barrels of water. Preliminary design studies are currently underway so that implementation time can be substantially reduced once a decision is made to waterflood the reservoir.

Laboratory work has been done by our Research Department in evaluating carbon dioxide as a possible means of tertiary recovery for Prudhoe Bay. Essentially, we found that miscibility pressure is considerably in excess of initial reservoir pressure. Although some additional work has been done with liquid petroleum gas enrichment of the CO_2 to lower miscibility pressures, reservoir characteristics of the Sadlerochit reservoir may limit its use to the shaly portions of the formation. Although no firm estimates of incremental recovery benefits have been made by my company, it is our opinion that these benefits would be smaller than those attributed to conventional water flooding. Since it appears that CO2 has some possibility for enhanced recovery in North Slope reservoirs, continuation of our studies is planned.

To summarize, Atlantic Richfield believes that the optimum production plan for the Prudhoe Bay Field includes early gas sales combined with a source water injection program. We have proposed and the State of Alaska has approved a gas sales rate of 2.0 BCFD beginning as soon as a gas transportation system is completed. We (and the State of Alaska) have found that gas deliveries of this volume will be non-injurious to the reservoir. Gas deliveries in excess of 2.0 BCFD must be approved by the State of Alaska. In addition, we feel that supplemental source water injection is certainly a means of increasing ultimate oil recovery. If our current estimates of incremental crude oil recovery benefits are substantiated along with the economic viability of the project, we anticipate that a source water injection program will be commenced as early as 1984. Accumulation of actual field production history will be invaluable in selecting the optimum volume as well as the optimum locations for this water. Again, approval of such an injection program will lie in the hands of the State of Alaska.

98-069 O - 78 - 17

You have requested that we estimate the gas delivery rates over the life of the field. If gas pipeline deliveries are commenced in 1983, we believe that the field will be capable of delivering gas at a rate of at least 2.0 BCFD for approximately 25 years.

I appreciate having an opportunity to appear before your committee today. Thank you.

BP ALASKA INC.
P. O. Box 4-1379
Anchorage, AK 99509

ATLANTIC RICHFIELD COMPANY
P. O. Box 360
Anchorage, AK 99510

October 20, 1976

Mr. O. K. Gilbreth, Jr., Director
Division of Energy and Minerals Management
Department of Natural Resources
3001 Porcupine Drive
Anchorage, AK 99504

Dear Mr. Gilbreth:

During the Prudhoe Bay Unit review with the State of Alaska, Department of Natural Resources on August 18, 1976, in Anchorage, a draft Unit Agreement was presented by the working interest owners for your early review. Included in the Unit Agreement was a recommended plan of operations which was discussed at the meeting with the understanding that further technical review of the basis for the recommended plan of operations would be provided. In response to your request, the attached report of comprehensive technical studies has been prepared by the field major interest owners, A.R.Co., BP, Exxon and Sohio. The "Technical Considerations, Prudhoe Bay Unit Operating Plan" report is submitted for your early review in advance of a formal application for Unit approval.

The recommended operating plan, which is supported by the attached report is, of course, based on the assumption that current unit negotiations are successful and that one oil rim participating area and one gas cap participating area are formed within the Permo-Triassic reservoir. In the unlikely event current unit negotiations are unsuccessful or modified significantly, revision to the recommended operating plan may be required.

The studies conducted by the major interest owners and described in the attached report have considered a range of possible production schedules, as well as a number of different reservoir management options. These studies include both subsurface and surface aspects of oil and gas production and have led to an overall reservoir management plan for the optimum development of the total energy resource in the Prudhoe Bay Field under unitized operations.

Mr. O. K. Gilbreth, Jr.
October 20, 1976
Page 2

The recommended operating plan is geared to producing the Prudhoe Bay Field in a timely manner consistent with good conservation and engineering practices while protecting the correlative rights of individual owners in both the gas cap and oil rim participating areas. The State of Alaska can be assured that the working interest owners, joining together within the Unit, will fully utilize their expertise to manage the field to obtain maximum economic recovery of oil and gas.

Following your review of the attached report, we are available, at your convenience, to meet with you for further discussion of the recommended operating plan for the proposed Prudhoe Bay Unit.

Respectfully submitted,

BP ALASKA INC.	ATLANTIC RICHFIELD COMPANY
K R Keep	
Kenneth R. Keep	Howard A. Slack
Vice President & General Manager	Vice President & Resident Manager

/vaf

Attachment

EXHIBIT A

TECHNICAL CONSIDERATIONS
PRUDHOE BAY UNIT OPERATING PLAN
NORTH SLOPE - ALASKA

TABLE OF CONTENTS

	Page
INTRODUCTION	1
OVERVIEW	3
RESERVOIR DESCRIPTION	9
Geologic Structure and Lithologic Units	9
In-Place Hydrocarbon Volumes	12
Reservoir Rock Properties	13
Fluid Properties	16
Aquifer Description	17
Saturation Functions	18
RESERVOIR STUDIES	20
Models	21
Operating Conditions	22
General Reservoir Performance	24
RESULTS OF RESERVOIR MODEL STUDIES	27
Recovery Estimates	28
Sensitivity Studies	30
RESERVOIR SURVEILLANCE AND TESTING PLANS	39
WATERFLOOD PLANNING STUDY	42
CONCLUSIONS	45

INTRODUCTION

On August 18, 1976, a draft of the proposed Prudhoe Bay Unit Agreement was presented to the Department of Natural Resources by the working interest owners. This was done in accordance with the Department's regulations which provide for submission of the draft form for preliminary consideration prior to agreement by the parties. Exhibit "E" of the proposed Agreement summarized a recommended plan of operations for the Unit. This report has been prepared by the major interest owners (A.R.Co., BP, Exxon, and Sohio) to provide the Department with the detailed technical basis for the recommended plan and will provide the operating plan data requested by the Department. The report is submitted for the Department's review in advance of a formal application for Unit approval. The subject Unit is currently being negotiated and the proposed plan is based on successfully concluding those negotiations.

This is a report of comprehensive technical studies which have been conducted independently over the past several years by the major working interest owners to develop long range operating plans. Major objectives considered in developing the operating plan for the Prudhoe Bay Field were (1) to achieve maximum economic recovery of oil and gas resources consistent with good conservation practices, (2) to develop energy resources as expeditiously as possible, and (3) to protect correlative rights. To fulfill these objectives, it is necessary to consider reservoir performance, efficient utilization of field facility and pipeline capacities, economic factors, and operational considerations such as mechanical feasibility and implementation schedules.

The recommended operating plan provides for the timely development of the total energy resource in the Prudhoe Bay Field consistent with good conservation and engineering practices and the recognition of the correlative rights of the owners in both the Gas Cap and Oil Rim participating areas in the proposed Unit. Over the life of the Field, these plans will undergo continual evaluation and will be modified as necessary, based on observed reservoir performance, to achieve the maximum economic recovery of oil and gas from the Prudhoe Bay Field.

OVERVIEW

Both short and long-term operating plans have been developed for the Prudhoe Bay Field. Short-term plans for oil and gas production from the Main Area Sadlerochit reservoir are as follows:

1. Oil production will begin in mid-1977 at a rate of 600 MB/D. The rate will increase to about 1.2 MMB/D by the end of 1977, assuming pipeline capacity is available.
2. Produced gas in excess of the quantity needed for local fuel requirements will be injected into the gas cap until a gas pipeline and gas conditioning plant are approved and constructed, currently estimated to be 4-1/2 to 5 years after start of oil production. Reinjection of produced gas will not adversely affect ultimate oil recovery.
3. Gas pipeline deliveries of 2.0 Bcf/D dry gas will begin as soon as a gas pipeline and gas conditioning plant are approved and constructed. The gas conditioning plant will be needed to bring the gas to pipeline quality including carbon dioxide removal, extraction of gas liquids for hydrocarbon dew point control, dehydration, and compression and cooling to pipeline pressure and temperature. Both the pipeline and conditioning plant require long lead times and large capital commitments. For example, preliminary estimates made several years ago indicate the gas conditioning plant will require 4-6 years for design, fabrication, and construction and will cost approximately $1 billion (1975 $). State approval of the gas offtake plan is needed now to insure that FPC certification, final design,

financing, and construction of the pipeline can proceed on schedule.

Main Area Sadlerochit reservoir performance characteristics expected with these planned offtake rates include (1) early expansion of the gas cap, (2) limited water influx from the aquifer, (3) coning of gas and water, (4) efficient natural gravity drainage depletion in areas with a thick oil column and good vertical permeability, (5) substantially less efficient natural depletion in areas where gravity drainage is ineffective, and (6) potential for improving performance in low natural recovery areas by selective injection of water.

To develop long range operating plans for the Prudhoe Bay Field, detailed reservoir studies have been conducted by the major interest owners (A.R.Co., BP, and Exxon) based on the substantial volume of Prudhoe Bay reservoir descriptive data which have been obtained and analyzed over the past seven years.

Sensitivity studies have also been made to insure that major operating plan decisions are practical over a reasonable range of reservoir properties. The results of these studies, combined with engineering judgment developed from experience in other fields have led to development of long-range reservoir management plans. Over the life of the field the plan will undergo continual evaluation, and, based on observed performance, will be modified as necessary to achieve the maximum economic recovery of oil and gas.

A long-range operating plan has been developed as follows:

Oil Offtake Rates

An increase in production to 1.5 to 1.6 MMB/D is planned when pipeline capacity is available. Field facilities designed for a sustained oil offtake rate of 1.5 to 1.6 MMB/D will be completed during 1978 and 1979.

It is anticipated that the 1.5 to 1.6 MMB/D average oil offtake rate can be maintained for approximately eight years by additional development drilling, resulting in efficient utilization of facility capacity. Such development of the field is expected to include 500 or more wells on 160-acre spacing within the 100-foot oil thickness contour. Production support can also be obtained through the installation of low pressure production and artificial lift systems or further infill drilling between some 160-acre spaced wells.

Studies of the sensitivity of reservoir performance to oil offtake rates in the range of 1.2 to 1.8 MMB/D indicate there is no significant effect of oil rate on the ultimate recovery of oil or gas. To sustain annual average offtake rates of 1.5 to 1.6 MMB/D, field facilities have been designed for a maximum capacity of 1.8 MMB/D. Consequently, some flexibility may exist to produce the field at higher rates when field and pipeline capacity are available.

Gas Offtake Rates

Gas pipeline deliveries of 2.0 Bcf/D are planned at the earliest date a pipeline can be approved and constructed, estimated to be 4-1/2 to 5 years after the start of oil production. Such gas deliveries are clearly a part of the optimum field operating plan. Studies have shown that the field can be operated so that planned gas deliveries will not affect ultimate oil recovery. The planned delivery rate of 2.0 Bcf/D is a conservative volume which can clearly be supported by the reservoir and initial gas pipeline deliveries of up to 2.5 Bcf/D may be justified, depending upon field performance data and availability of pipeline capacity.

Planned gas pipeline deliveries will substantially increase domestic energy supplies. For instance, through year 2000, pipeline deliveries of 2.0 Bcf/D, beginning 5 years after the start of oil production, add the energy equivalent of 2 billion barrels of oil to the nation's energy supply. In addition, such gas deliveries reduce fuel consumption, eliminate unnecessary costs for compression, injection, and "double production" of gas, and provide a measure of correlative rights protection for the Oil Rim and Gas Cap participating area owners.

Water Injection Plans

Produced water injection into the Sadlerochit reservoir is planned when the volumes become significant. Initially, water production will be minimal and disposal will be by injection into the shallow Cretaceous sands. When water production becomes significant, plans are to selectively inject into areas of the reservoir which experience low primary oil recovery to achieve maximum additional oil recovery benefits. Projections indicate that produced water injection will increase primary recovery by as much as 2% of the original oil-in-place (OOIP).

Initially, there will be field capacity to inject up to 200 MB/D of produced water and additional capacity will be provided as needed. Without source water injection, produced water rates could be as high as 500 MB/D with ultimate injection of some 4 billion barrels of water.

Produced water injection will be supplemented with the injection of extraneous source water when the additional recovery predictions of 3 to 7% of OOIP from such water injection are verified and the economic viability of the over $1 billion project is ascertained. Reservoir performance and testing data are particularly important to determine the proper water injection locations and volumes. Consequently, final commitment to source water injection cannot be made at this time, although it is planned and will be implemented if current predictions are verified.

In terms of additional oil recovery, the major benefit of water injection is improved sweep efficiency. Consequently, the timing of source water injection is not very critical to ultimate oil recovery. It is more important that the water be injected in the proper volumes and at the proper locations to obtain optimum field performance. If a source waterflood is initiated with insufficient production data, it could be improperly designed. For example, if there are areal differences in aquifer response (which is likely in a field with such a large areal extent), water could be injected into an area which may experience substantial local aquifer influx. The likelihood of such potential errors in both volume and location can be reduced with production history and test data.

A comprehensive reservoir surveillance and testing program will insure that necessary reservoir information is obtained at the earliest possible date. Although water injection plans cannot be finalized at this time, preliminary design studies are proceeding to reduce the lead time to approximately 3 years for implementation once the final decision to inject source water is made.

Summary

The operating plan described herein provides the flexibility necessary to adapt, as required, to information obtained from field performance to allow the maximum economic recovery of oil and gas. Studies indicate that it will be possible to manage the field to recover approximately 40%

of the original oil-in-place (OOIP) and 75% to 80% of the original gas-in-place (OGIP) in the Main Area Sadlerochit reservoir of the Prudhoe Bay Field.

RESERVOIR DESCRIPTION

Circumstances over the last seven years have permitted the working interest owners to secure unusually detailed reservoir descriptive information prior to the commencement of production. Highly specialized studies and analyses of geologic history, core data, fluid sample data, and log data have been made to determine in-place hydrocarbons for ownership determination and to refine estimates of reservoir parameters which influence reservoir performance. Production performance and test data will allow further refinement of the key data interpretations, particularly the vertical to horizontal permeability ratios, relative permeability, the effect of shale barriers, and the effectiveness of the aquifer.

The reservoir description presented in this section covers the range of data interpretations developed independently by the major interest owners. Generally, the individual interpretations of reservoir descriptions are in close agreement. There were differences in the manner in which individual companies translated the reservoir description into reservoir simulation models. While the performance predictions from the models are not identical, the studies lead to the same conclusions regarding major provisions of the field operating plan.

A. Geologic Structure and Lithologic Units

Figure 1 is a structure map on top of the Sadlerochit sand which was prepared by the Proposed Prudhoe Bay Unit Geological Subcommittee. Limits of the hydrocarbon accumulation in the Sadlerochit reservoir are defined by faults, truncation of the reservoir rock and the oil-water contact. Faulting provides the northern limit while the gentle south-dipping flank is relatively uncomplicated with the oil-water contact providing the limit. The east flank of the Sadlerochit reservoir is truncated by the Lower Cretaceous unconformity. Complex northwest-southeast trending fault systems establish the productive limits in the northwest portion of the Main Area. Immediately to the west of the Main Area is the Eileen Area which is fault bounded to the southwest with a generally northeast-dipping flank.

In the Main Area Sadlerochit, the gas-oil contact occurs at a subsea elevation of 8578 feet; while in the Eileen Area, two small gas caps are defined in separate fault blocks. The gas-oil contacts for the eastern and western fault blocks are at 8792 and 8770 feet subsea, respectively. The water-oil contact is an irregular surface and is slightly tilted, ranging from about 9050 feet subsea in the eastern portion of the Main Area to a subsea elevation of slightly above 8950 feet in the Eileen Area.

Figure 2 is a typical log from a well which completely penetrates the Sadlerochit formation. This log contains all of the Sadlerochit subdivisions defined by the Proposed Prudhoe Bay Unit Geological Subcommittee and exhibits the log characteristics which were used to make the subdivisions. Zone 1 represents a transition facies of interbedded sandstones and shales between the underlying marine shales and the overlying more massive fluvial sands. This zone is further subdivided, as shown, into Sub-Zones 1A and 1B. Sub-zone 1A is the more shaly of the two subdivisions as indicated on the Gamma Ray log response.

Zone 2 is a series of more massive sandstones interbedded with fairly significant shales. These shales become more massive and continuous offstructure and into the aquifer, as would be expected with the depositional source being from the north. The lithology is predominately sandstone with increasing amounts of conglomerate toward the top of the zone. The three major continuous shales within this zone, as shown on Figure 2, occur at or near the top of Zone 1, in the lower third of Zone 2, and in the upper half of Zone 2. Although no agreed nomenclature has been adopted, for purposes of this report these shales have been designated A, B, and C, respectively.

Zone 3 is a conglomeratic interval which is present over most of the field but thins to the west, south, and east until it eventually disappears beyond the productive limits of the field. This zone represents the highest energy level of the southward flowing streams and contains essentially no shale. Zone 3 is easily identified by its lower porosity reflected on the sonic log with its top and base defined by an 85 microsecond cut-off.

The uppermost subdivision of the Sadlerochit, Zone 4, is a more homogeneous sandstone facies with minor discontinuous shales or mudstones. It represents a lower energy fluvial environment. The final major shale (D), which appears to be continuous over a significant portion of the Sadlerochit productive area occurs at the base of Zone 4 or near the top of Zone 3. The top of the Sadlerochit is marked by an unconformity and is picked on a correlative Gamma Ray peak underlain normally by a pyritic streak evidenced by a low response on the resistivity logs and a high reading on the density log.

98-069 O - 78 - 18

As will be shown later in the report, the geologic description, particularly the identification of extensive shales which are important to reservoir performance and the selection of reservoir management plans, and the lithologic zonation have been used extensively in Prudhoe Bay modeling studies.

B. <u>In-Place Hydrocarbon Volumes</u>

The hydrocarbon-in-place volumes for the Permo-Triassic reservoirs (Sag River, Shublik, and Sadlerochit formations) in the Main and Eileen (West End) Areas were determined through a joint technical study by the Proposed Prudhoe Bay Unit Reservoir Engineering Subcommittee. The results of this study are summarized in Figure 3. Oil rim and gas cap gas-in-place volumes for the Permo-Triassic are 31.2 billion reservoir barrels and 26.6 trillion standard cubic feet, respectively.

The Main Area Sadlerochit contains over 93% of the oil-in-place, with the Eileen Area Sadlerochit, the Sag River, and the Shublik totaling less than 7%. Reservoir simulation studies have concentrated primarily on the Main Area Sadlerochit because it represents such a large portion of the oil-in-place. It is likely that development of the Eileen Area Sadlerochit, the Sag River, and the Shublik will follow full development of the Main Area.

A heavy oil/tar zone occurs throughout the Main Area Sadlerochit just above the water and contains much poorer quality crude than the "light oil" column above it. This zone contains 1.9 billion reservoir barrels of hydrocarbons and represents about 6.5% of the Main Area Sadlerochit oil rim volume.

C. Reservoir Rock Properties

Core data were utilized extensively in development of the rock properties used in the reservoir models of the Main Area Sadlerochit formation. As indicated in Figure 4, 33 wells have been cored in the Main Area and 8 wells in the Eileen Area, for a total of over 9000 samples. Areal distribution of the data is good and will continue to improve as key wells are cored throughout the development drilling phase.

All core samples have undergone routine lab analysis for porosity using the summation of fluids technique. Horizontal and vertical permeabilities were measured using air and reservoir fluids. Special tests were also conducted on selected samples for determination of relative permeability and capillary pressure relationships.

1. Porosity

Relationships between core and log data were developed to extrapolate the core data fieldwide. Three porosity logs (sonic, neutron, and density) are available on each well, but the sonic log was found to be preferable for calculating porosity in the Sadlerochit. Porosity-transit time relationships were established for each lithology and fluid type. With the relationships established, average porosity was determined for the net pay in each lithology in each well on a foot-by-foot basis.

The Gamma Ray log was used to exclude all shale or non-pay intervals. Isoporosity maps were developed for each lithology. Each map indicated some degree of downstructure degradation in porosity, consistent with sediment deposition from a northern source. Figure 5 indicates the range of porosity for each lithology in the Main Area Sadlerochit.

2. Horizontal Permeability

Core data were also utilized to develop permeability-porosity relationships for zones exhibiting similar characteristics. The foot-by-foot permeabilities calculated from logs using the porosity-permeability relationships were averaged by zone and then zonal isopermeability maps were developed. Permeability data from pressure buildup tests were also considered.

Figure 5 indicates the range of permeability of each zone of the Main Area Sadlerochit. The permeability range varies from a high of greater than 1000 md in the conglomeratic Zone 3 to about 100 md in Zone 1. All zones exhibit varying degrees of downstructure permeability degradation.

3. Vertical Permeability

Effective vertical permeability in the reservoir cannot be obtained directly from the core data due to reductions caused by small discontinuous shales. These shales cannot be correlated from well-to-well and their areal extent cannot, therefore, be exactly defined. Since vertical permeability is expected to have a significant impact on recovery, considerable effort was devoted to its evaluation. A statistical analysis of shale frequency was made from logs, and the areal extent of the shales was estimated from studies of modern day braided streams. Based on the data developed in these studies, a 28,500 grid block 3-D model was used to estimate their effect on vertical flow. Major correlatable shales also have a significant effect on vertical permeability as will be discussed later.

The range of Kv/Kh ratios used in the model studies is shown in Figure 5. Additional drilling, field testing, and reservoir performance data will be needed to verify this key parameter.

4. Correlatable Shales

Major shales, which are correlatable between wells, also occur within the Sadlerochit section (Figure 2). These shales were deposited in a bay environment as opposed to the braided stream environment of the minor, non-correlatable shales. Where possible, these shales were mapped and included in reservoir models as zero vertical permeability boundaries. For example, Figure 6 is a map showing the areal extent of the "D" shale over the Sadlerochit productive area.

These correlatable shales will have a significant effect on gas-oil and water-oil contact movement. In addition to their influence on gross fluid movement in the reservoir, these shales will dramatically affect the gas and water coning behavior of individual wells. Model studies show that continuous shales could provide injection control and thereby, improve waterflood performance in specific areas of the field. However, a complication could arise in that faults could allow communication across these shales.

D. Fluid Properties

Initial reservoir pressure in the Main Area ranges from 4335 psia at the gas-oil contact to about 4480 psia at the water-oil contact. Reservoir temperature varies both vertically and areally. At 8800 feet subsea, temperature varies from about 185°F in the northeast part of the field to 240°F in the Eileen Area. At these initial conditions, oil gravity in the "light oil" column of the Main Area averages about 27°API, varying from 30°API at the gas-oil contact to about 26°API at the top of the heavy oil/tar zone. The oil formation volume factor averages 1.36 RB/STB and varies from about 1.3 to 1.4 RB/STB while oil viscosity averages about 0.8 centipoise and varies from 0.5 to 1.2 centipoise. Solution gas-oil ratio averages about 750 SCF/STB, varying from about 650 to 900 SCF/STB between the gas-oil contact and the heavy oil/tar zone in the Main Area.

A gas cap gas condensate yield of about 35 barrels per million cubic feet of separator outlet gas is expected initially from the separator facilities located at the flow stations (gathering centers). In addition, it is expected that once gas sales begin, 10-15 barrels of gas liquids per million cubic feet of separator outlet gas will be extracted at the gas sales conditioning plant to make the gas acceptable for delivery into the gas pipeline.

Gas pipeline specifications are not currently known and final specifications may increase or decrease the volume of liquids which must be extracted from the gas to prevent condensation in the pipeline. Regardless of the final gas conditioning requirements, all liquids extracted will be used without waste; either to displace fuel gas or be transported through the oil pipeline.

Fluid properties of the heavy oil/tar interval are also important considerations. This interval, located just above the water throughout the Main Area, is distinctly different from the "light oil" column above it. An isopach of the zone (Figure 7) shows that the interval varies in thickness from 20 to 60 feet, being generally thinner in the southeastern third of the field. Well tests confined to this interval experienced only small amounts of fluid entry with oil gravities of less than 15°API. Analyses of cores from this zone indicate a low effective permeability to brine (approximately 1 millidarcy). Model studies indicate that the presence of the heavy oil/tar zone will offer some impedance to water influx although the effect on ultimate influx is expected to be relatively minor. The heavy oil/tar zone could have a more significant impact on peripheral water injection plans because of reduced injectivity. Reservoir performance and testing information will be necessary for final evaulation of the impact of the heavy oil/tar zone.

E. Aquifer Description

Figure 8 shows the aquifer properties, volume, and location of wells from which logs and core data were available. A total of 26 wells have been drilled in the Sadlerochit aquifer with core data obtained from 10 of these wells. Although the aquifer covers a large area, net sand thickness and quality appear to degrade rapidly moving away from the oil column. As shown by the inset of Figure 8 only about 35% of the aquifer volume is in rock with permeability of greater than 10 md.

The rapid degradation of rock properties in the Sadlerochit aquifer is expected to result in only limited water influx. Production history will provide necessary information to accurately quantify aquifer performance.

F. Saturation Functions

The range in the basic relative permeability curves used by the companies in their respective reservoir studies is shown in Figures 9 and 10. These curves are based on detailed laboratory analyses using several different techniques. Oil-water relative permeability data were obtained from waterflood tests run on core plugs and composite cores, some at reservoir conditions using reservoir fluids. Some oil-water relative permeability centrifuge tests were also run. Similar tests were used to obtain gas-oil relative permeability data.

Three-phase relative permeability values were determined from two-phase laboratory data by use of empirically derived probability models. In some of the simulation studies, history-dependent saturation functions developed from laboratory data have been used. Initial conditions in such models are established with drainage saturation functions and continue to use the drainage functions until there is a decrease in the non-wetting phase saturation. Once that occurs, hysteresis scanning curves are used to describe the transition to the imbibition functions.

Although extensive, sophisticated laboratory analyses have been conducted, final confirmation of relative permeability effects will depend upon data from field production performance and special well tests. Such information is needed for accurate assessment of water-oil displacement efficiency which is of critical importance in planning water injection programs.

RESERVOIR STUDIES

Extensive studies have been performed independently over the years by the owners in the Prudhoe Bay Field. The results of these studies represent a consensus assessment of the productive capabilities of the Main Area Sadlerochit reservoir and are supported by experience in producing similar types of fields throughout the world.

Reservoir performance studies have been integrated with downhole and surface facility considerations. Such factors affect production performance and ultimate reserves and are important aspects in the development of a sound, comprehensive plan of operation for the field.

The operational factors which have been considered are mechanically feasible for Prudhoe Bay operations and are typical considerations in the operation of other fields. Such factors include well density, field pressure systems, artificial lift, gas reinjection, facility capacity for handling produced water and gas, well workovers, and optimum water injection locations and volumes.

Costs of such operational factors are important in developing an operating plan to insure that it is economically feasible. Since the same production performance objectives might be accomplished with more than one of the operational alternatives, comparative costs are important to insure optimized operations. Lead times for the design, construction, and installation of field facilities are also important aspects of field management considered in developing the operating plan.

Where uncertainties exist, both in operational considerations and in the reservoir description, studies have been conducted to evaluate the sensitivity of ultimate oil and gas recovery for a reasonable range of uncertainty. The sensitivity studies have led to the development of a plan of operation which has the necessary flexibility to allow for a positive reaction to observed performance.

The following subsections describe the reservoir models used in the studies, the operating boundary conditions applied in the models and the general reservoir performance characteristics observed in the models.

A. Models

Major interest owners have compared and exchanged results of independent two-dimensional, three-phase cross-sectional model studies of the Main Area Sadlerochit. While results are not identical, the overall conclusions drawn regarding the field operating plan are the same. The fact that independent reservoir description and simulation efforts led to the same operating plan provides further confidence in the overall conclusions.

Two-dimensional, three-phase cross-sectional models were employed for the basic studies of long-range reservoir performance and the evaluation of overall reservoir management options, although the application of other models was necessary, particularly individual well models for studying coning and completion intervals. Cross-sectional models were selected because they adequately take into account: (1) the significant changes in rock properties which occur vertically and with position on structure, (2) vertical flow and gravity segregation which tends to dominate in a thick sand with fairly good vertical permeability, (3) gas cap expansion and water influx, and (4) the important influences of oil column thickness and fluid contact movement on the behavior of wells at different structural positions.

The cross-section models utilized by the three companies contained 14 or 15 vertical layers and 67 to 90 grid blocks horizontally. Separate studies were made with more finely gridded models to confirm that this grid definition reduced numerical error to within acceptable limits. Reservoir properties assigned were based on each company's interpretation of the basic reservoir data described previously and were within the ranges shown in the Reservoir Description section of this report. As might be expected with independent studies of this nature, there are many differences in the model descriptions. Despite these differences, the results and conclusions from the studies are very similar.

Numerous additional models have been utilized to compliment and verify the cross-sectional studies of the Sadlerochit reservoir. Two-dimensional areal models were used for aquifer sensitivity studies. Radial models describing typical wells have been utilized to study gas and water coning behavior and identify optimum completion intervals. Finely gridded two and three-dimensional model studies of portions of the reservoir have been made to confirm the large block models and evaluate displacement mechanisms in localized areas. Fieldwide three-dimensional, three-phase models have been used to analyze areal variations in reservoir performance and to confirm results of the cross-sectional models.

B. Operating Conditions

Well rates in the models were controlled by the productivity index of the completion interval as calculated from producing block thickness, rock permeability, and relative permeability values based on fluid saturations in the producing blocks. Damage ratios from

1.5 to 3.5 were based on interpretation of the production tests in the field. Well capacities considered the effects of wellbore hydraulics for the flow conditions predicted by the simulator and the planned tubular equipment. Artificial lift (both gas lift and pumping) was included when additional capacity was needed to sustain the target oil producing rate.

Completion intervals were chosen in conjunction with coning model studies. Generally, initial standoffs from the gas-oil contact were 150 to 200 feet while 50 to 100 feet standoff from the water-oil contact was maintained. Initial oil rates averaged about 10,000-12,000 B/D, but varied widely. Recompletions were allowed under various conditions, such as when an adequate production increase could be obtained, or when some present water-oil ratio (WOR), gas-oil ratio (GOR) or field facility capacity was reached.

The models considered approximately 500 wells developed on 160-acre spacing within the 100' oil thickness contour. In a number of cases, some infill 80-acre development wells are included.

Prior to gas sales, gas production volumes were limited to the injection capability of about 1.8 to 2.0 Bcf/D, plus field fuel requirements. During gas sales, gas production volumes included pipeline delivery volumes plus fuel, shrinkage and carbon dioxide (CO_2) removal. Because of these factors, a 2.0 Bcf/D pipeline delivery level requires production of 2.7 to 2.8 Bcf/D of raw gas.

A peak oil rate of 1.5 MMB/D and gas pipeline deliveries of 2.0 Bcf/D after 4-1/2 to 5 years of oil production were generally assumed, although higher oil and gas offtakes were evaluated. Water injection rate, timing, and location were varied in attempting to optimize the reservoir management plans studied.

C. General Reservoir Performance

Conclusions regarding reservoir performance characteristics, as defined by cross-sectional, coning, and other model studies, are:

1. Natural water influx is expected to be substantially less than required to fully maintain reservoir pressure. The modest contribution of the aquifer is due primarily to the degradation of rock properties that occurs with distance from the field.

   Sensitivity studies have been run to evaluate the effectiveness of the aquifer by assuming variations in the expected size, permeability, rock and water compressibility, and transmissibility across faults in the west area of the field. Over a reasonable range of values, water influx is relatively low.

2. The natural depletion mechanisms are gravity drainage, gas cap expansion, solution gas drive and water influx. The influence of gravity drainage is especially important in those areas with a thick oil column and good vertical permeability.

3. During early years of production, the gas cap expands rapidly, moving vertically into the oil rim at a rate of about 25 feet per year and advancing thousands of feet horizontally to override much of the oil zone at the top of the sand and under massive, continuous shale breaks. This early expansion of the gas cap eliminates concern that depletion of the gas cap during oil production might

result in a reduction in recoverable oil due to gas cap shrinkage.

4. Although completion intervals will be designed to take maximum advantage of shale protection and standoff distances from the original contacts, gas and water coning will eventually occur.

5. It is expected that significant volumes of gas cap gas will be produced through oil wells. If this gas is not delivered to a pipeline, it will be necessary to reinject an estimated 15-20 Tcf of gas into the gas cap. Although the return of such gas is not detrimental to reservoir performance, compression and injection of this volume of gas would require approximately 600-800 Bcf of fuel gas, or the energy equivalent of more than 100 MM barrels of oil. Moreover, the extraction of liquids required to condition the gas for pipeline delivery will provide for an additional 10 MM barrels per year of gas liquids.

6. The onset of oil production decline is largely controlled by the advance of the gas-oil contact. Increasing gas-oil ratios ultimately result in the gas handling capability being exceeded at which point oil production must be restricted. Since the advance of the gas-oil contact is related primarily to net oil zone withdrawals, gas sales timing does not significantly affect oil production decline. Source water injection does offer potential to delay oil decline by retarding advance of the gas-oil contact.

7. Model studies indicate that, taking into account the effect of coning, the 1.5 to 1.6 MMB/D oil rate can be sustained for about eight years.

8. The examination of a wide range of assumptions regarding oil and gas offtake rates leads to the conclusion that the reservoir can be managed to recover approximately 40% OOIP and 75% to 80% OGIP.

RESULTS OF RESERVOIR MODEL STUDIES

During the past several years of studying the Sadlerochit reservoir, each company has experienced an evolution in model development. Studies with early models considered a broad spectrum of reservoir management plans, while recent work has focused on the more reasonable alternatives. These studies have investigated the effects of varying both reservoir properties and operational factors on production peformance.

As discussed earlier in the report, there are uncertainties which relate to reservoir description, such as vertical-to-horizontal permeability ratio, shale continuity, and relative permeability which have an impact on ultimate recovery and on decisions relating to reservoir management options. Studies have been made to evaluate the potential impact of these factors on the plan of operation.

Factors related to field development and operations also affect production performance and ultimate recovery. For the Prudhoe Bay Field, such factors include the return of produced gas and water to the reservoir, source water injection, well density, gathering system pressures, artifical lift facilities, and the capacity of facilities for handling oil, water, and gas production. Simulation model studies have also been made to evaluate the effect of these operational factors on overall reservoir performance. Comparisions between cases have typically been made through changing one or two of the more significant factors at a time.

These sensitivity studies have made it possible to develop sound operating guidelines for the Prudhoe Bay Field which will provide necessary flexibility to modify the operational factors as reservoir properties are better understood. Such studies, combined with experience in other

98-069 O - 78 - 19

fields, result in confidence that optimum oil and gas recovery can be attained in the field even though the reservoir description may be different than the current interpretation. The considerable areal extent of the field will likely require that operations be optimized in a number of different ways to best suit local conditions. For instance, water injection may prove to be highly desirable in selective areas where natural depletion recovery is low, but much less desirable in areas with very efficient oil recovery through gravity drainage.

A. Recovery Estimates

The following paragraphs describe the estimated ultimate oil and gas recovery from the Main Area Sadlerochit reservoir at Prudhoe Bay under the oil and gas offtake conditions of a peak oil rate of 1.5 MMB/D and a gas pipeline delivery rate of 2.0 Bcf/D commencing 4-1/2 to 5 years after the start of oil production along with various water injection alternatives.

Due to the favorable reservoir rock properties which provide for good gravity drainage, the natural recovery mechanism (without return of produced water) at Prudhoe Bay will be efficient with oil recovery predicted by the companies ranging from 32% to 35% of OOIP. It is estimated that this oil recovery will be achieved over a period of 25 to 30 years. Ultimate gas recovery is expected to be in the range of 75% to 80% of total gas-in-place and will be recovered over a period of about 35 years.

Studies have indicated substantial benefits of injecting produced water into the Sadlerochit reservoir. Such water injection could involve rates as high as 500 MB/D and ultimate injection of up to 4 billion barrels. By selectively injecting this water to obtain maximum benefits, ultimate oil recovery may be increased as much as 2% OOIP. The range of recovery predicted by the companies for this plan is from 33% to 36% OOIP. The current operating plan calls for the injection of produced water into the Sadlerochit when volumes become significant.

Model studies indicate further potential for increasing ultimate oil recovery to a level of 39% to 40% OOIP by implementing a properly designed source water injection program within about five to nine years after the start of oil production. Selection of the optimum locations and volumes to be injected will be the key to the success of a source water injection program. Two or more years of production performance history and testing data will be necessary to select optimum locations and volumes and to confirm the additional recovery potential of 3 to 7% OOIP before the final decision is made to commit approximately one billion dollars for source water injection facilities. It will then take a minimum of three years to develop the final design, fabricate, and install the first stage of the source water injection system. As will be shown later, sensitivity studies indicate that ultimate oil recovery is not very sensitive to the timing of injection startup in the 5 to 9-year period. The studies indicate that it is possible to inject at higher rates and "catch up" with the later injection programs. Based on these projections, the current operating plan for the field includes source water injection programs to be implemented when performance and testing information confirm the need and allow selection of optimum locations and volumes of source water injection.

B. Sensitivity Studies

Numerous case studies were analyzed by the companies to evaluate the sensitivity of reservoir performance to operational factors which can be controlled, such as offtake rates, well density, and water injection. In evaluating the sensitivity of reservoir performance to these factors, potential variations in reservoir properties were also considered. Results of these sensitivity studies can be summarized as follows:

1. Oil Offtake Studies

Sensitivity studies to oil offtake rate in the range of 1.2 to 1.8 MMB/D indicate no significant effect of oil rate on the ultimate recovery of oil or gas.

2. Gas Offtake Studies

Model results have shown that the timing of 2.0 Bcf/D of gas pipeline deliveries does not significantly affect ultimate oil recovery under sound reservoir management plans. The sensitivity of oil recovery to the timing of gas offtake was investigated by delaying gas deliveries until 8-1/2 to 10 years after the start of oil production. Studies have shown that the minor potential reduction in ultimate oil recovery resulting from the earlier gas sales can be offset in the field by modifying one or more operating options, such as the number and location of wells, gathering system pressures, the volume and location of water injection, and the capacity of facilities for handling gas and water.

Assuming available pipeline capacity, increases in gas deliveries above 2.0 Bcf/D may be considered depending upon future reservoir studies and reservoir performance. Model studies have shown that the gas delivery rate can be increased from 2.0 Bcf/D to 2.5 Bcf/D without affecting ultimate oil recovery if appropriate modifications are made to the reservoir management plan. These studies were conducted without economic analysis and justification for gas sales rates above 2.0 Bcf/D will depend upon actual production performance and economic considerations.

3. Well Density Studies

The current operating plan anticipates approximately 500 wells on 160-acre spacing inside the 100-foot oil thickness contour line. Studies indicate potential for enhancing production performance by infill drilling between 160-acre spaced wells in selected parts of the reservoir, but such decisions will depend upon reservoir performance.

4. Water Injection - Rate and Timing

Water injection case studies indicate potential for increasing ultimate oil recovery to a level of 39% to 40% OOIP by implementing a well designed source water injection plan. As indicated previously, the earliest feasible implementation date for a source water injection project is approximately five years after the start of oil production. However, such timing may not provide adequate opportunity to analyze production performance. Therefore, studies have been made with water injection commencing seven to nine years after start of oil production. Results of these studies indicate ultimate oil recovery is not very sensitive to the timing of injection startup and that the later injection programs result in the same recovery if the rate of injection is increased.

The key to a successful source water injection program will be the selection of the optimum locations and volumes to be injected, which may vary from one area of the field to another, depending on local reservoir conditions. For instance, shale continuity, the effectiveness of injection into or below the heavy/oil tar zone, aquifer response, and natural depletion performance may influence desired injection locations. The major benefit in terms of additional oil recovery derived from water injection in the Sadlerochit reservoir is improved conformance or sweep efficiency. Additional recovery results primarily from water displacement in areas of the reservoir which experience inefficient recovery under the natural depletion process. Because of the complex and diverse nature of the field, selection of the optimum well locations will require field production performance and testing data.

Eight typical water injection sensitivity studies which demonstrate these effects are summarized in Figure 11. A single model (reservoir description) was used in these studies. All operational factors and offtake rates were held constant except for the indicated variations in the gas delivery and water injection programs. Produced water was returned to the reservoir in all cases. Cases 1 through 4 resulted in the recovery of approximately 39% OOIP with water injection timing varying from 5 to 9 years after beginning oil production. Injection rates for these four cases varied between 1.7 and 2.6 MMB/D. Cases 5 through 8 recovered approximately 40% OOIP with water injection timing varying from 5 to 7 years after beginning oil production. In Cases 5 through 8, injection rates varied between 2.0 and 3.5 MMB/D.

The difference in ultimate oil recovery among these cases is relatively small compared to the difference in the volumes of water injected. Increasing volumes of water injection yield diminishing benefits in terms of incremental oil recovery. Larger injection volumes also require more fuel, additional handling of produced water, and greater volumes of gas-lift gas. The results also indicate that the timing of gas pipeline deliveries does not significantly affect ultimate oil recovery.

The methods finally used in operating the Prudhoe Bay Field will depend on the overall economics which consider the optimum recovery of all hydrocarbons, fuel requirements, the relative cost for different operating procedures, and incremental benefits of the alternative secondary recovery programs.

The individual cases can be summarized as follows:

Cases Recovering 39% OOIP

Case 1:

The water injection program for this case involved startup after five years of oil production. The peak injection rate was 1.7 MMB/D with cumulative injection totaling 8.5 billion barrels through 20 years of oil production. Water was injected into areas which experience poor recovery under natural depletion and where shales can be utilized to control the water in the reservoir. Initially, source water was confined to the shaly areas in the lower one-half of the oil column and the natural gravity drainage mechanism was allowed to continue updip. After adequate gas invasion (7 years), injection was commenced updip behind the gas front in those areas where the "D" shale is continuous and can be utilized to confine the injection to Zone 4.

Case 2:

Source water injection was initiated after seven years of oil production in the same locations as in Case 1. By increasing the peak injection rate to 2.0 MMB/D, the same ultimate oil recovery was obtained as in the earlier water injection case. The source water injection locations utilized in Cases 1 and 2 are the most efficient that could be developed for the model. Even so, comparison with a natural depletion case with produced water injection indicates that for each incremental barrel of oil recovered, it is necessary to inject approximately 15 barrels of water.

Case 3:

In this case, source water injection was deferred until nine years after the start of oil production and the peak injection rate was increased to 2.5 MMB/D. Oil production had declined from the peak rate of 1.5 MMB/D prior to the start of source water injection. Although injection was concentrated in the shaly areas, some was injected in the flank in a peripheral pattern. While some rate acceleration benefits of water injection were sacrificed, the deferral of source water injection startup did not affect ultimate oil recovery.

Case 4:

Gas pipeline deliveries were initiated at 2.5 Bcf/D after five years of oil production. The water injection plan in the oil zone, which was started after seven years of oil production, was identical to the water injection plan in Case 2. In addition, water was injected into the gas cap beginning five years after the start of oil production. This case, with higher gas offtake rate, resulted in the same ultimate oil recovery as Case 2.

Cases Recovering 40% OOIP

Case 5:

Gas pipeline deliveries were deferred until 10 years after the start of oil production. Oil zone water injection was initiated after seven years of oil production at the same volumes and locations as in Case 2. Although the five-year delay in gas deliveries slightly improved ultimate oil recovery, Cases 6, 7 and 8 demonstrate that other water injection programs achieve the same oil recovery with gas deliveries commencing after 5 years of oil production. Moreover, as described previously, deferral of gas pipeline deliveries increases fuel requirements for reinjection and substantially decreases the total energy supply from the field during the early years.

Case 6:

This case reflects an early, large water injection program. Source water injection was initiated after five years of oil production at the peak rate of 3 MMB/D. Because the gas cap had not advanced sufficiently by this time, it was not feasible to inject updip in the oil zone above continuous shales. Such injection would have caused significant volumes of oil to be driven into the original gas cap. To avoid this, the water was injected into the gas cap, the shaly areas in the lower one-half of the oil column, and in the flank of the oil column in a peripheral pattern.

Case 7:

Water injection into the gas cap was initiated as in Case 6 after five years, but injection into the oil zone was deferred until seven years after the start of oil production to allow additional advance of the GOC so that a portion of the water could be injected updip in the oil column. The improved efficiency with this water injection plan offset the earlier start of water injection in Case 5. The importance of the location of injection is expected to be even more pronounced in the field where there are significant variations and complexities which cannot be considered in a simulation model.

Case 8:

In this case, source water injection was started after seven years and built to a peak rate of 3.5 MMB/D. Because this volume was larger than could be confined to only the more efficient areas, it was necessary to inject in the unconfined flank of the oil column and in the gas cap. In total, increasing the injection rate from 2.0 MMB/D in Case 2 to 3.5 MMB/D in Case 8 increased oil recovery by less than 1% OOIP. On an incremental basis, it was necessary to inject more than 35 barrels of water for each additional barrel of oil recovered. This demonstrates that the benefits derived from water injection diminish with increasing volumes because the additional water must be injected into areas of the reservoir which respond less favorably to water displacement.

In summary, these water injection sensitivities demonstrate that (1) ultimate oil recovery levels can be maintained with timing of source water injection varying from 5 to 9 years after the start of oil production with modifications to the water injection program, (2) injecting source water in the optimum locations and at the proper volumes may be more important than the timing of injection startup, (3) the benefits of source water injection diminish with increasing volumes of injection, and (4) adjustments to the water injection program is one method of compensating for potentially adverse effects of the timing or volume of gas pipeline deliveries ranging from 2.0 Bcf/D to 2.5 Bcf/D. These studies, as well as experience in other reservoirs, indicate that it is prudent to evaluate reservoir performance and the results of field testing before making final source water injection decisions.

RESERVOIR SURVEILLANCE AND TESTING PLANS

As discussed in the previous section on simulator study results, operating guidelines have been formulated with sufficient flexibility to accomodate variations in reservoir performance from that predicted. The key to optimizing the reservoir management plan and recognizing deviations from predicted performance is a thorough program of reservoir surveillance and testing. Surveillance activities will include monitoring pressures and gas-oil and oil-water contact movements, and observing the performance of individual wells.

In addition to the regulatory requirements for initial static pressures in all wells and regular pressure surveys in key wells, it is planned that pressures in the gas cap and aquifer will be monitored. Selected wells may also be completed prior to their connection to producing facilities to provide virtually continuous pressure observations within the oil column and gas cap during the early stages of production.

Cased hole neutron logs will likely provide the best indication of gas-oil contact movements, although other tools will be run to provide confirmation. A comprehensive cased-hole baseline logging program is currently being developed.

Water-oil contact movements will be monitored with pulsed-neutron baseline logs (e.g., TDT-K and carbon-oxygen logs) run in selected wells. The gamma ray log has also proven successful in locating water in certain instances and the gamma ray will be run routinely during the completion of each well. Open-hole logs will provide additional spot checks on contact movements for a number of years as development wells continue to be drilled in the field.

The information obtained from the pressure and contact surveys will be analyzed to evaluate such parameters as shale continuity, displacement efficiencies, and aquifer response.

Comprehensive well test procedures are planned, including measurements of productivity index (PI), gas-oil ratio (GOR), and water-oil ratio (WOR) and regular samples of both produced oil and separator gases.

Special interference, pulse, and vertical permeability tests will be conducted to provide information such as effective vertical permeability and the extent of communication across faults and shale intervals.

Production logging will be intensive shortly after startup to monitor the flow distribution of fluids entering the wells and to provide information regarding the continuity between sand members. For these purposes, flowmeters and possibly noise logs and/or radioactive tracers will be run. In problem wells, other surveys might also be necessary, e.g., flowing temperature, gradiomanometer, etc.

Within two years after the start of production, it is planned that water injectivity tests be performed in selected locations. The objectives of such tests would be to (1) determine the injectivity into various subzones under sustained injection conditions to determine the number and location of injection wells and (2) to determine from such tests whether water displacement characteristics in the reservoir confirm present laboratory information obtained from cores. It is considered impractical to make detailed plans for a large-scale waterflood without obtaining such vital information.

Reservoir simulation modeling will also be an integral part of the overall reservoir surveillance program. As production data are gathered, history matching will be utilized to update the models. Projections of future performance will allow continuing evaluation of various operating alternatives.

WATERFLOOD PLANNING

Once adequate reservoir performance information is available to allow evaluation of the desirability and optimum plan for a source water injection program, about three years are required to develop the final design, fabricate, and install the system. Although three years is a tight schedule to install the first increment of a source water injection system at Prudhoe Bay, it is achievable based on recent experience gained in installing production facilities. Production facilities for 1.2 MMB/D of oil will have been completed in approximately 3-1/2 years from the beginning of detail design work. During this period construction expertise has been gained and extensive support facilities have been constructed, all of which will be used in future Prudhoe Bay construction projects, including source water injection systems.

In order to keep construction lead time to a minimum, a detailed Waterflood Planning Study has been initiated which will provide necessary information concerning water source, water treating requirements, potential water freezing problems, environmental considerations, and equipment and material requirements. Based on Arctic construction experience and worldwide waterflood experience, technology exists to solve anticipated Prudhoe Bay waterflood problems, however, numerous optimization studies are necessary to assure the economic viability of the project.

One phase of the Waterflood Planning Study that has already received considerable effort is water treating requirements, including filtration, deaeration, and chemical treatment. The major intent of this preliminary study is to obtain water samples from the Arctic Ocean at Prudhoe Bay on a seasonal basis. In March and June, 1976, an extensive sampling program was conducted. The March sampling was taken during conditions of thick ice and minimum turbidity while the June sampling occurred during the time of maximum river run-off. The results of both of these sampling programs indicate the Arctic water to be of good quality. Dissolved solids and biological studies indicate rapid settling rates and essentially sterile conditions. Oxygen content of the water is low and deaeration may only be necessary during periods of rapid river run-off. Overall, results indicate that the Arctic Ocean can be used and is the most likely source of injection water.

The Cretaceous water sands which overlie the Sadlerochit reservoir at Prudhoe Bay have also been considered as a potential source. However, these sands are poorly consolidated and developing them as a water supply would likely require the drilling of a large number of wells, special sand control completion techniques, and the use of high-volume submersible pumps. While these early indications suggest that the Cretaceous may not provide an adequate long-term, high-volume supply of injection water, these sands may be useful as a source of injection water for localized areas.

Studies conducted over the past several years have indicated that source water injection is mechanically feasible at Prudhoe Bay. However, water injection rates, location, and total volumes appear to be as important to the overall success of a water injection project as the mechanical optimization requirements. Consequently, the reservoir and mechanical aspects of the project must be evaluated concurrently. The preliminary Waterflood Planning Study currently in progress should be completed in mid-1978 at which time more detailed design studies can begin. These studies will continue concurrent with the gathering and analysis of field

98-069 O - 78 - 20

performance history which is necessary before a final decision to inject source water can be made.

CONCLUSIONS

1. The proposed Prudhoe Bay Unit operating plan provides for sustained oil offtake rates of 1.5 to 1.6 MMB/D after 1978, assuming available oil pipeline capacity, and gas pipeline deliveries of 2.0 Bcf/D as soon as gas pipeline facilities and a conditioning plant can be approved and constructed (4-1/2 to 5 years after the start of oil production). This plan provides for expeditious and economic development of the total energy resource at Prudhoe Bay consistent with good oil and gas conservation practices. Approval of the gas offtake plan is needed now to insure that gas pipeline and conditioning plant projects can proceed on schedule.

2. The planned oil offtake rate is supported by sensitivity studies which indicate that in the range of 1.2 to 1.8 MMB/D, oil rate has no significant effect on the ultimate recovery of oil or gas.

3. The planned gas pipeline sales from Prudhoe Bay, when begun, will immediately increase current energy to the consumers and current income to the owners, eliminate fuel requirements and unnecessary costs for injecting produced gas, and provide for a measure of protection for the correlative rights of owners in the Oil Rim and Gas Cap participating areas of the proposed Prudhoe Bay Unit. With appropriate reservoir management, the planned gas offtake rates will have little or no effect on ultimate oil recovery.

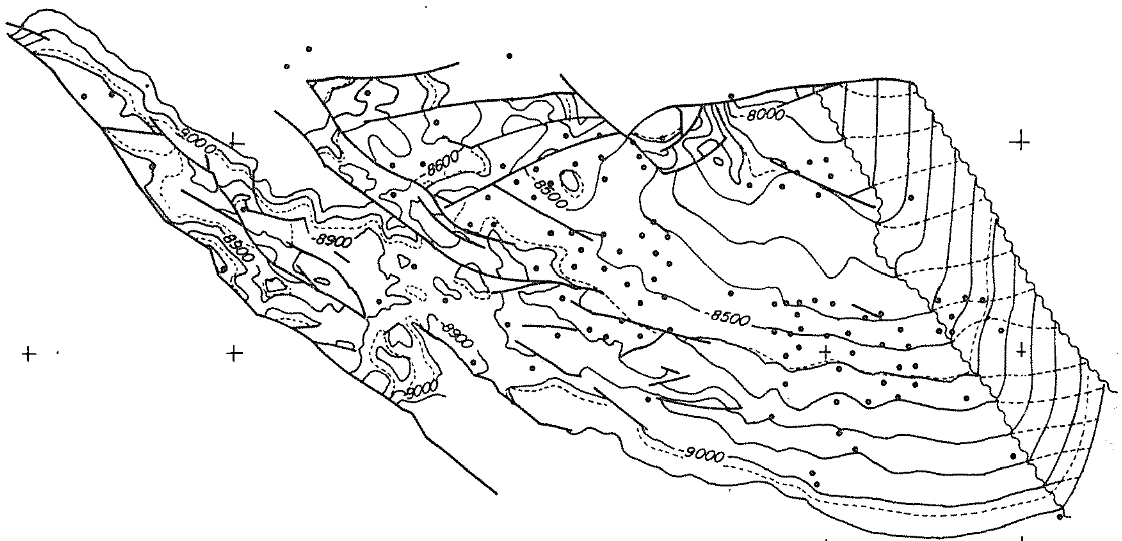
A gas conditioning plant is required to remove carbon dioxide, extract excess gas liquids, dehydrate, and cool the gas to meet pipeline specifications. The final design of gas conditioning facilities will depend upon gas pipeline pressure and specifications. Gas liquids extracted during conditioning will either be blended with the crude and condensate for transportation through the oil pipeline or utilized as fuel.

4. Injection of produced water into certain areas of the Sadlerochit reservoir with poor natural depletion performance will be beneficial to ultimate oil recovery. The current plan is to selectively inject produced water into the Sadlerochit reservoir when water production volumes become significant.

5. Potential exists for additional oil recovery by the implementation of a well designed source water injection program. Within reasonable limits, the timing of source water injection startup is not as critical as injecting proper volumes of water at the optimum locations. Reservoir surveillance and testing information obtained during the first few years of production will provide information necessary to confirm the desirability and define the optimum plan for source water injection. Preliminary design studies currently underway will shorten the implementation time once final decisions can be made. Although final commitment cannot be made at this time, the current plan anticipates that source water injection will be initiated within five to nine years after the start of oil production.

6. Studies indicate that depending on overall economic considerations, oil recovery of about 40% OOIP (8.5 billion barrels) can be achieved from the Main Area Sadlerochit reservoir for a reasonable range of operating conditions and reservoir descriptions. These reserves do not include additional production from the Eileen Area, other Permo-Triassic formations or gas liquids. An expected ultimate gas recovery of approximately 75% of the total gas-in-place in the field results in dry gas reserves of about 26 trillion cubic feet (after removal of gas liquids and non-hydrocarbons).

FIGURE 1
STRUCTURE MAP
TOP OF SADLEROCHIT SAND



3950

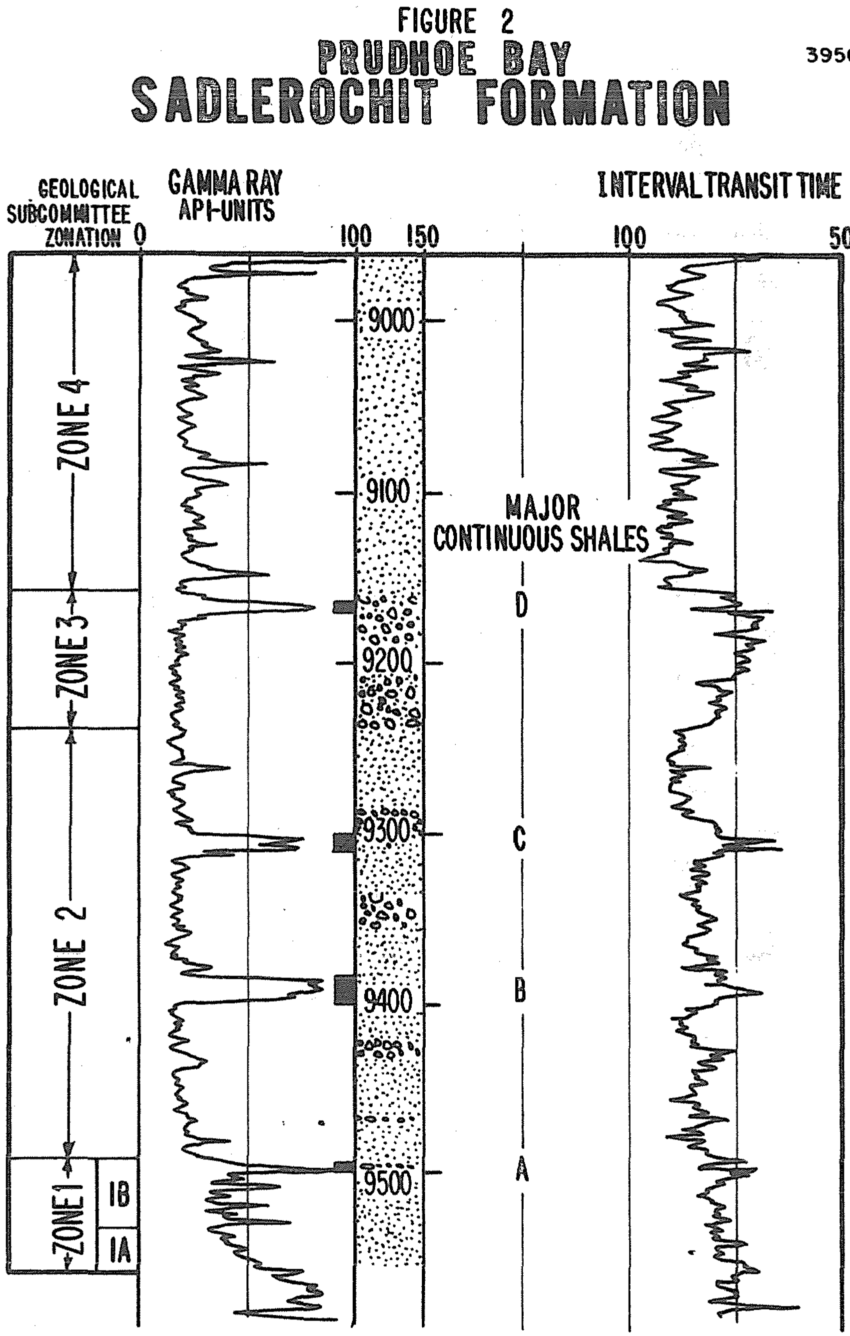


FIGURE 2
PRUDHOE BAY
SADLEROCHIT FORMATION
GEOLOGICAL SUBCOMMITTEE ZONATION
GAMMA RAY API-UNITS
0
100
150
INTERVAL TRANSIT TIME
100
50
ZONE 4
ZONE 3
ZONE 2
ZONE 1
IB
IA
9000
9100
9200
9300
9400
9500
MAJOR CONTINUOUS SHALES
D
C
B
A

3955

FIGURE 3

PRUDHOE BAY FIELD

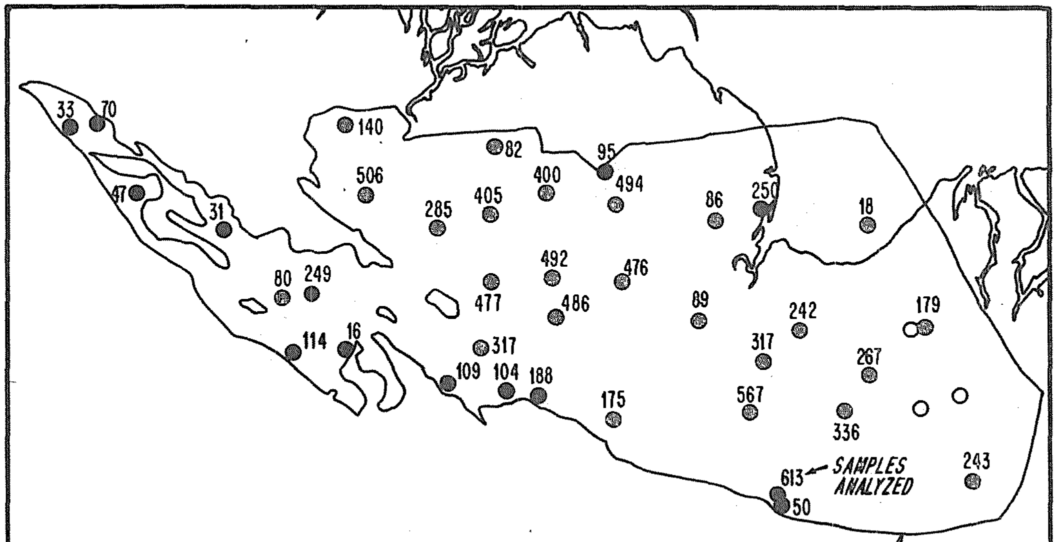
IN-PLACE HYDROCARBON VOLUMES

SAG RIVER, SHUBLIK & SADLEROCHIT FORMATIONS

	MAIN AREA			EILEEN AREA			TOTAL
	SAG	SHUB	SADL.	SAG	SHUB	SADL.	
GAS CAP (TSCF):	3.6	0.1	22.4	0.2	—	0.3	26.6
OIL ZONE (MMMRB):							
LIGHT OIL	0.8	0.1	27.2	0.1	<0.1	1.1	29.3
HEAVY OIL/TAR	—	—	1.9	—	—	—	1.9
TOTAL	0.8	0.1	29.1	0.1	<0.1	1.1	31.2

FIGURE 4
PRUDHOE BAY FIELD
CORE DATA & ANALYSIS
SADLEROCHIT RESERVOIR

3945-A



	EILEEN AREA WELLS	EILEEN AREA SAMPLES	MAIN AREA WELLS	MAIN AREA SAMPLES
● CORE DATA ANALYZED	8	640	30	8488
○ WELLS RECENTLY CORED			3	

FIGURE 5
PRUDHOE BAY
SADLEROCHIT FORMATION

3951

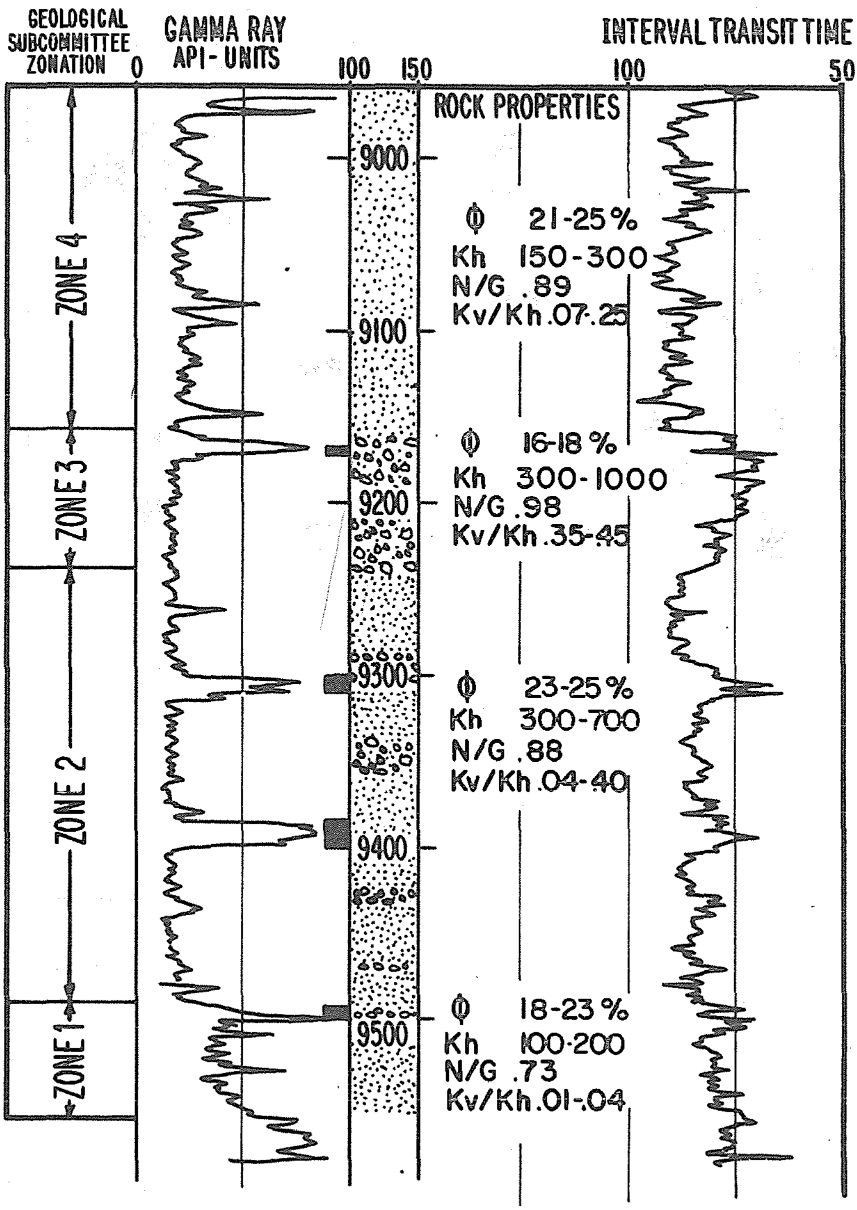


FIGURE 6
PRUDHOE BAY AREA

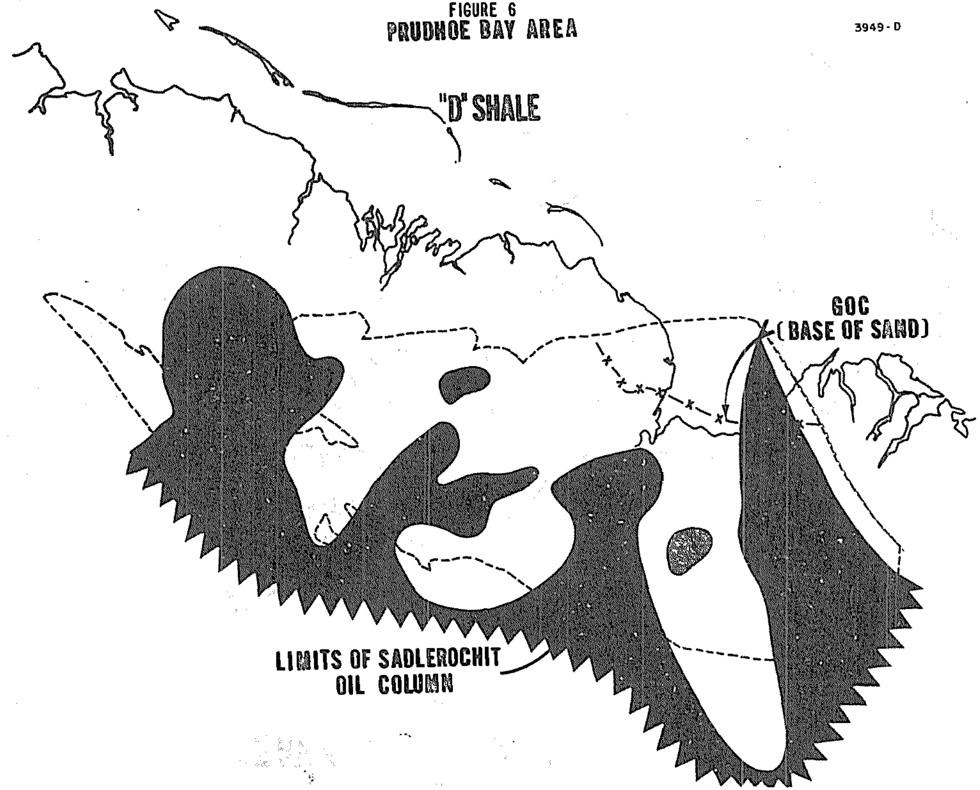
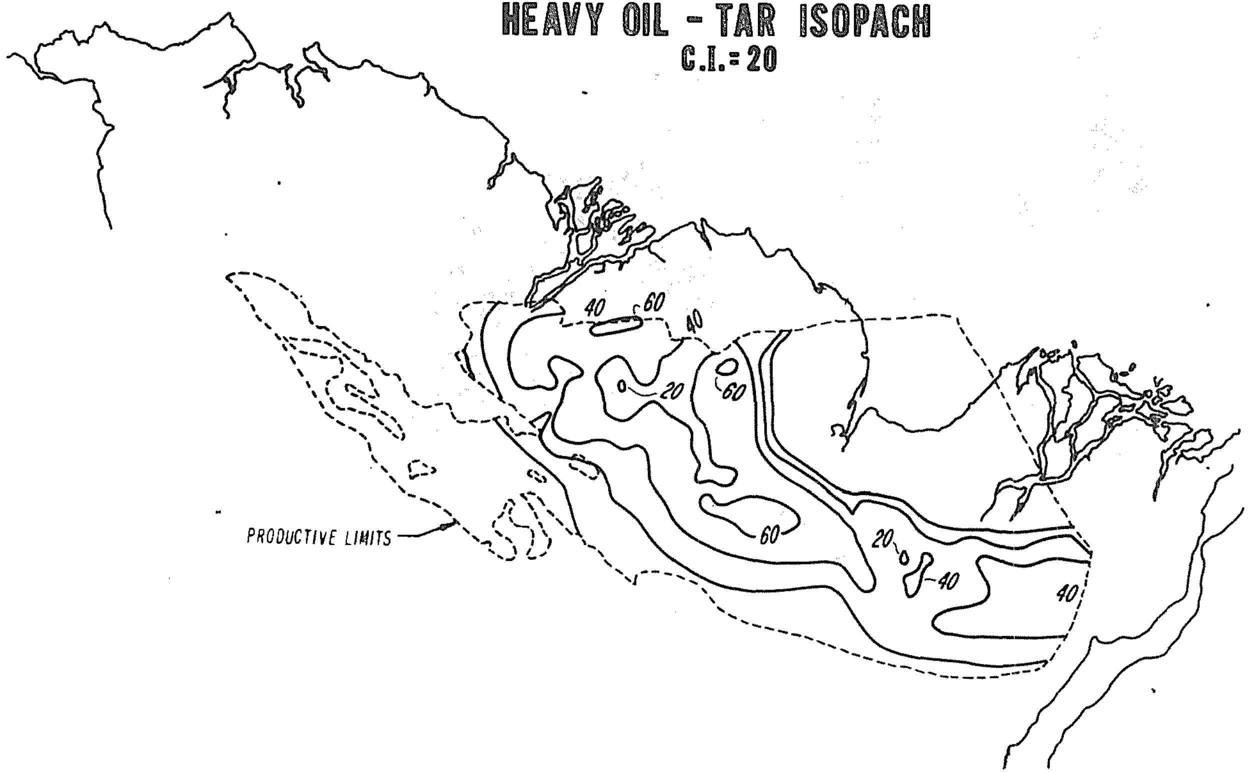


FIGURE 7

HEAVY OIL - TAR ISOPACH

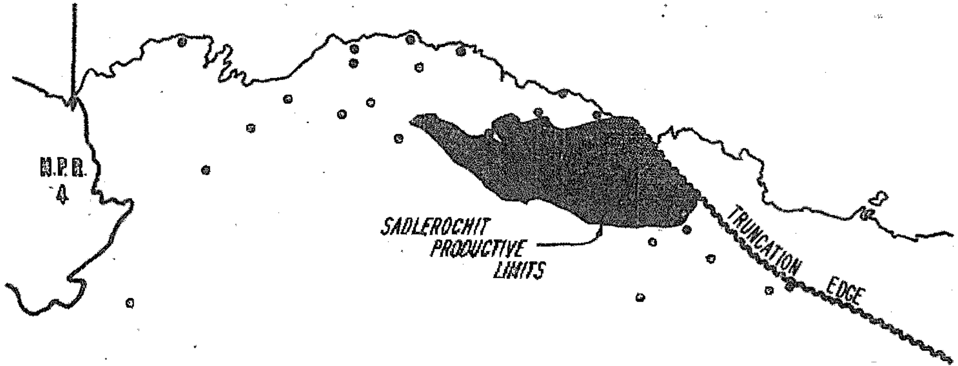
C.I.= 20



3944

FIGURE 6

PRUDHOE BAY FIELD
AQUIFER DESCRIPTION
SADLEROCHIT RESERVOIR



DIST. FROM OWC (mi)	AVG. PROPERTIES Φ (%)	K (md)	AQUIFER VOL. (Billion RB)
1.	20.6	225	36
5	18.1	80	163
10	15.3	25	308
15	13.5	12	400
25	11.4	5	705
50	9.1	2	1150

FIGURE 9
SADLEROCHIT WATER-OIL IMBIBITION
RELATIVE PERMEABILITY
(20% CONNATE WATER SATURATION)

3952

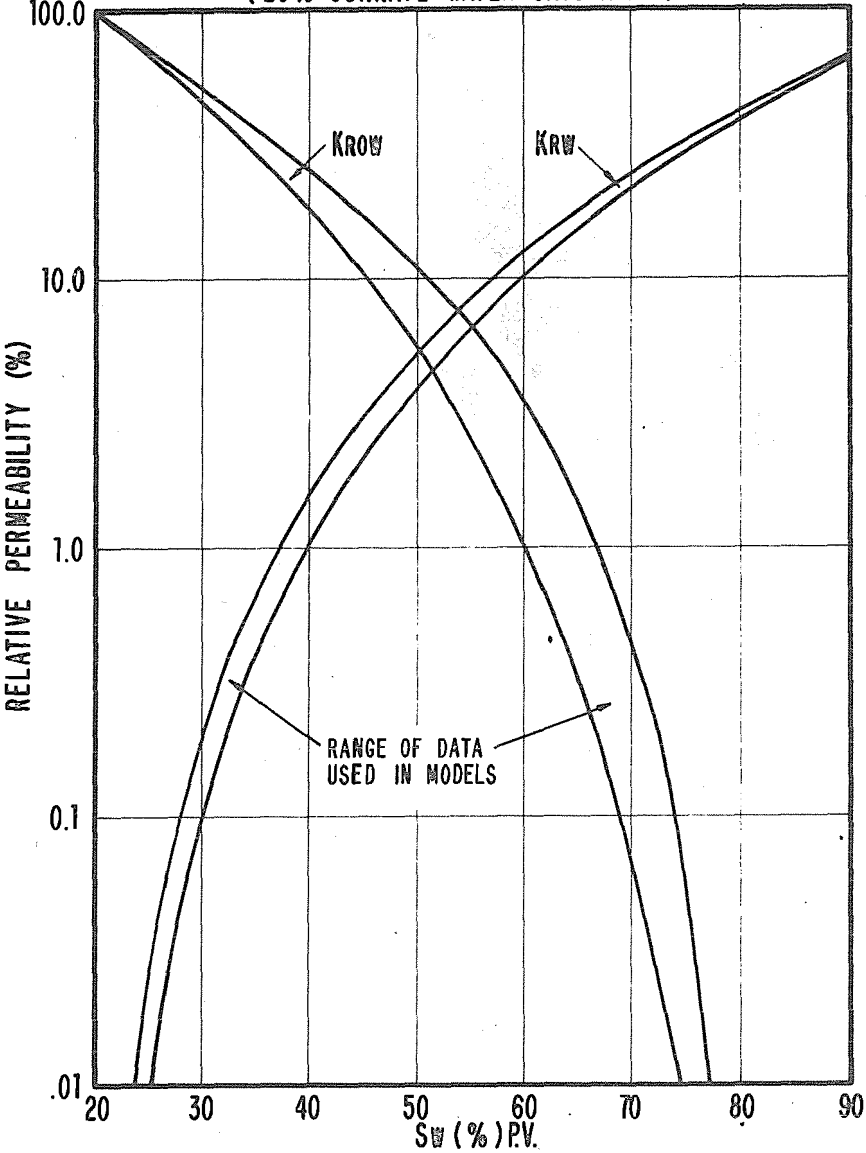


FIGURE 10
SADLEROCHIT GAS - OIL DRAINAGE
RELATIVE PERMEABILITY
(20% CONNATE WATER SATURATION)

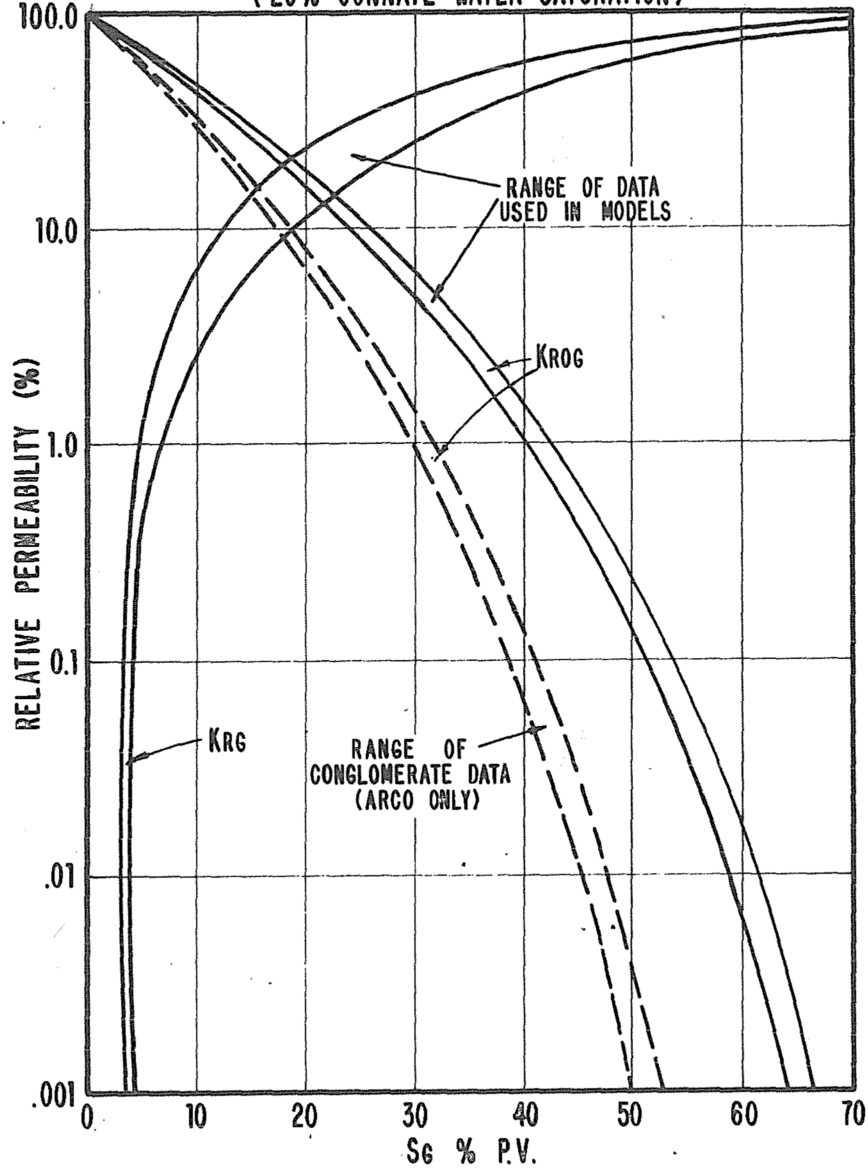


FIGURE 11

WATER INJECTION CASE STUDIES
MAIN AREA SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD, NORTH SLOPE, ALASKA

Case No.	Water Injection Program: Startup (Yrs. of Prod'n)	Water Injection Program: Peak Rate (MMB/D)	Water Injection Program: Total Injection thru 20 years (MMMB)	Gas Pipeline Deliveries: Start (Yrs. of Prod'n)	Gas Pipeline Deliveries: Rate (Bcf/D)
CASE STUDIES RECOVERING APPROXIMATELY 39% OOIP:					
1.	5	1.7	8.5	5	2.0
2.	7	2.0	8.6	5	2.0
3.	9	2.5	10.0	5	2.0
4.	7/5	2.6	11.8	5	2.5
CASE STUDIES RECOVERING APPROXIMATELY 40% OOIP:					
5.	7	2.0	8.6	10	2.5
6.	5	3.0	12.4	5	2.0
7.	7/5	3.0	12.2	5	2.0
8.	7	3.5	15.6	5	2.0

Senator HANSEN. Next to testify will be Dr. K. T. Koonce, Operations Manager, Western Production Division, Exxon USA.

Dr. Koonce, we will be pleased to hear from you.

STATEMENT OF DR. K. T. KOONCE, OPERATIONS MANAGER, WESTERN PRODUCTION DIVISION, EXXON USA, HOUSTON, TEX.

Dr. KOONCE. Thank you, Mr. Chairman. As you indicated I am Alaska operations manager for the western division of Exxon USA. Prior to assignments in Exxon's Production Department, I spent 10 years with Exxon's production research affiliate. For more than half of this time I was directly involved in and managed reservoir research and engineering studies for Exxon's worldwide operating affiliates.

I appreciate the opportunity to appear before this committee and to testify on a subject so vital to the Nation's energy supply.

Exxon believes strongly that it is in the common best interest of the Nation and all concerned, including the producers, to maximize recovery of both oil and gas at Prudhoe Bay and elsewhere. We firmly believe that the plan of operation developed for the Prudhoe Bay field is sound and that the estimated oil recovery of 40 percent will be achieved.

Exxon's experience in other fields supports this relatively high recovery efficiency. While we do not operate the Prudhoe Bay field we have a substantial working interest in the oil and gas and are assisting the operators with the technical skills necessary to maintain an operating plan that maximizes recovery.

Exxon participated in drilling the discovery well in 1968; since that time massive amounts of data have been collected and thoroughly analyzed to develop the best possible description of the Prudhoe Bay field. Exxon, in conjunction with its research affiliate, has independently analyzed rock and fluid properties. Reservoir rock properties have been determined from more than 10,000 samples from over 40 wells and confirmed by approximately 50 production pressure tests. Fluid distribution in the reservoir is based on the rock samples and over 70,000 feet of well logs from 175 wells. Fluid properties have been derived from over 40 samples of the oil and gas in the reservoir. Displacement efficiencies have been determined from extensive lab tests, many of which were conducted at reservoir temperature and pressure conditions using actual reservoir rock and fluids.

Using this extensive data base we have been actively involved in conducting independent reservoir performance studies necessary for development of a fluid operating plan. We have taken into account comparisons with other producing fields and have employed proven reservoir engineering technology, including the use of the most advanced models and similar techniques available. Exxon alone has devoted about 50 man-years and 700 hours of computing time to Prudhoe Bay reservoir studies.

Our studies support the operating plan for the Prudhoe Bay field which includes:

First, an annual average oil offtake rate of 1.5 million barrels per day when oil pipeline capacity is available. Our studies have shown essentially the same oil recovery for oil offtake rates ranging from 1.2 to 1.8 million barrels per day. At the planned offtake rate, oil production is projected to decline after 1987 at a normal rate of about 14 percent per year.

Second, the plan includes gas pipeline deliveries of 2 billion cubic feet per day as soon as a gas transmission system can be completed. It is estimated that this gas delivery can be sustained for 20 to 25 years before declining.

Third, low pressure and artificial lift systems are planned when needed to maintain productive capacity, and fourth, injection of produced water into the reservoir is planned as soon as those volumes become significant, now estimated to be within 2 to 4 years. Additionally, injection of water from a source external to the reservoir can begin within about 7 years when additional oil recovery benefits are confirmed and the optimum injection locations and volumes are determined. This timing is adequate to achieve maximum benefits of waterflooding.

The detailed studies supporting this plan were presented to the State of Alaska Division of Oil and Gas Conservation and their consultant during the course of technical meetings required by the division in 1975 and 1976 and were summarized at the public pool rules hearing in Anchorage on May 5 and 6 of this year.

We are confident that the approved operating plan has sufficient flexibility to accommodate variations in reservoir performance from that predicted. The key to recognizing these variations and optimizing the operating plan is a thorough program of reservoir surveillance and testing. Such surveillance activities include monitoring pressures, gas-oil contact movement, oil-water contact movement, and individual well performance. These activities have been approved by the State of Alaska Division of Oil and Gas Conservation and are incorporated in the field rules.

In the course of our reservoir performance studies, the possible application of tertiary recovery programs has also been considered. Exxon maintains a considerable research effort devoted to developing viable tertiary recovery techniques, but we know of no such techniques that would be applicable at Prudhoe Bay on a fieldwide basis. The industry has many field tests of tertiary processes underway in more mature fields in the lower 48. As such research and development continues, we will examine the potential use of tertiary recovery methods in the Prudhoe Bay field.

I would like to comment briefly now on Dr. Doscher's testimony. In June and July of this year reservoir engineers from Exxon as well as BP and ARCO, met twice with Dr. Doscher. The purpose of the meetings was to allow him to review the studies which served as the basis for the operating plan approved by the State of Alaska. At the close of those discussions Dr. Doscher took no exception to the approved operating plan for the field, which includes gas sales. We are not aware of any independent analyses that he had conducted at that time or has conducted since that time. Consequently, we do not understand how, based on existing studies, he could have reached the conclusions he stated before this committee on October 12.

As we previously testified before the State of Alaska, our studies show that there is sufficient operational flexibility to make gas sales of 2 billion cubic feet per day without adversely affecting ultimate oil recovery.

Simulation studies conducted independently by the field operators and numerous consultants for the State of Alaska, Department of Interior, and gas pipeline applicants also support the preferred plan of operation for the field including early gas sales.

It is unfortunate that confusion has arisen in the proceedings of this committee in spite of such overwhelming evidence. In Exxon's view the committee should move forward in its consideration of the gas pipeline with confidence that Prudhoe Bay gas can be produced without adversely affecting oil recovery.

In conclusion, the approved operating plan for the Prudhoe Bay field meets the major objectives we feel are important.

First, it provides for the timely development of the total Prudhoe Bay energy resource, both oil and gas. The earliest possible development of Prudhoe Bay gas is extremely important since it represents 12 percent of proven domestic gas reserves. The Department of Interior and Federal Power Commission have stated that Prudhoe Bay gas is competitive with alternate energy sources and its development has a positive net national economic benefit.

Second, the reservoir will be managed to achieve the maximum recovery of both oil and gas, consistent with sound engineering practices.

Third, the plan provides the flexibility necessary to respond to actual reservoir performance so as to maintain efficient recovery of oil and gas from the field.

In view of the critical need for domestic energy supplies, Exxon believes the prompt and efficient development of Prudhoe Bay oil and gas resources is in the common best interest of the producers, the State of Alaska, and the Nation.

Thank you, Mr. Chairman.

Senator HANSEN. I have some questions, Dr. Koonce, that I intend to ask of all witnesses. The President's decision assumes that the pipeline's throughput will average 2.4 billion cubic feet of gas per day. What do you believe the average throughput will be over the life of the field?

Dr. KOONCE. As you know, the approved operating plan includes 2 billion cubic feet per day from the Prudhoe Bay Field. Of course, there is a potential for additional discoveries on the North Slope. As far as I can say the Prudhoe Bay proven gas is all that we currently can show.

Senator HANSEN. What oil production will be necessary to sustain that rate, the 2 billion cubic feet or 2.4?

Dr. KOONCE. Oil production?

Senator HANSEN. Yes.

Dr. KOONCE. The basic oil production rate is consistent with maintenance of that rate and that is moving to 1.5 million barrels per day when that kind of pipeline capacity is available.

Senator HANSEN. Will that rate require early production of gas from the gas cap?

Dr. KOONCE. I think it is important for all of us to understand that the actual voidance of the gas cap is going to come reasonably late in development of the Field. Senator Stevens mentioned that it may be as many as 8 years before the gas pipeline would actually be in operation. During that period of time the solution gas from the oil will be reinjected and that will be 2 to 3 trillion cubic feet of gas. So it will actually be in excess of 10 years before there is any net voiding of the gas cap.

Senator HANSEN. Will your company participate in paying for the cost of the gas conditioning plant, or does Exxon believe this expense is a responsibility of the gas pipeline project?

Dr. KOONCE. Senator, with all due respect I am here as a technical witness with expertise in reservoir management and production operations. One of our senior officers, Mr. Larry Rawl testified before the subcommittee 2 weeks ago and I would be happy to submit his testimony and questions and answers to the committee for the period.

Senator HANSEN. If it is responsive to that question I think that would be indicated. If not, perhaps you could convey this question to the appropriate officials in your company and they could submit a response for inclusion in the record.

Dr. KOONCE. We certainly will. [See appendix.]

Senator HANSEN. Will Exxon provide debt guarantees? I might note parenthetically that it is my understanding that the President's decision assumes the State of Alaska and the oil producers will build the plant and assist with debt guarantees and having noted that may I repeat again, will Exxon assist the financing of the gas pipeline project by providing debt guarantees? Perhaps again if I could anticipate your role here today that's a question you might like to refer to your colleagues.

Dr. KOONCE. Yes, all of the questions that you asked Dr. Koch in that vein I believe are addressed in Mr. Rawl's testimony and subsequent testimony and we will submit those.

Senator HANSEN. You have referred to studies which show gas sales at 2 billion cubic feet per day will not affect oil recovery. Would you supply the committee with these reports?

Dr. KOONCE. Yes, we will certainly be willing to discuss those with the committee at any time.

Senator HANSEN. Thank you very much.

Senator Stevens.

Senator STEVENS. Thank you very much, Mr. Chairman.

Dr. Koonce, the decline in projected oil production which Dr. Doscher mentions, and I believe you have heard it mentioned here already today, is that based upon the 9 billion barrel figure estimated for Prudhoe?

Dr. KOONCE. Yes, that decline is consistent with the total 9.6 or 7, possibly 9.8 billion barrels of total liquid.

I would like to say here, Senator, that the decline is not precipitous. The decline, as Dr. Koch indicated, is very normal.

Senator STEVENS. That's 14 percent per year, you said?

Dr. KOONCE. That's correct, and that is quite normal.

Senator STEVENS. Well, in terms of your role with Exxon do you contemplate additional production from beyond the Prudhoe Bay, from the North Slope?

Dr. KOONCE. Senator, we certainly hope so. That's highly dependent on the success of exploratory efforts.

Senator STEVENS. I mean have you based your options on the fact that additional oil will be discovered? Is that part of the package of assumptions that the plan has proceeded on?

Dr. KOONCE. No, sir, not as far as the Prudhoe Bay operation is concerned.

Senator STEVENS. Well, then if we are producing and transporting 1½ million barrels per day for 9 years and it falls off at 14 percent per year if I am correct it is about 210,000 barrels a year it is going to decline. How long will it take to get down to the 500,000 barrels a day that Dr. Doscher mentioned?

Dr. KOONCE. Senator, I don't have that exact projected date.

Senator STEVENS. Do you disagree with that conclusion of his?

Dr. KOONCE. No, sir. It will decline to roughly that rate in roughly that period of time, yes.

Senator STEVENS. It wouldn't be 210,000 barrels, it would be 21,000. But in any event, we have an oil pipeline that has cost us $7.6 billion and we have got a gas pipeline coming along that's going to cost, in addition, $10 to $15 billion, and I find it intriguing that the producers have not projected, as I asked of Dr. Koch, and again I am not being antagonistic, but in view of the increased cost the pipeline was originally going to cost a little over $1 billion. It was up to $1.5 billion the first time I heard. The pipeline is going to cost $5 or $6 billion. Now they say $10 to $15 billion. In view of the inflation cost why haven't the producers explored other options, particularly the two-phased operation of the oil pipeline?

Dr. KOONCE. Let me make several comments about that, if I may. First of all, we certainly are extremely hopeful that there will be additional reserves developed north of the Brooks Range, both on the North Slope and at sea.

If we try to utilize an oil pipeline to transport gas we seriously jeopardize the incentive to explore for additional oil reserves in that area.

Second, the technical problems associated with a two-phase flow line of 48 inches in diameter are absolutely enormous. We have looked into this. We have thought about it. To the best of my knowledge no two-phased line exists that requires any supplemental compression or pumping. There are two-phase lines in the field where the pressure itself carries the oil and gas to a separator where the two are separated, but there are enormous problems with moving oil and gas in a line that size 800 miles through sophisticated pumping equipment which certainly is not designed to have any gas in the oil. This would mean at a bare minimum the oil and gas would have to be separated frequently, recompressed and repumped and recombined.

We do not think that a two-phased 48-inch line is practical in any sense of the word.

Senator STEVENS. Have you done any computer runs on it?

Dr. KOONCE. I would not say that we have done computer runs on it, but we have looked at some hand calculations and you can see just as the line goes up and down the tremendous problems you get into with the liquid settling in the low places and gas rising to the high places. It is a prohibitive problem.

Senator STEVENS. I take it you would dry the gas if you were going to use two-phase whether you used one pipeline or two, wouldn't you? There wouldn't be any liquids in the gas that is put in a two-phased oil pipeline but there wouldn't be the same problem in a one-phased pipeline.

Dr. Koonce. You would dry the gas, certainly. You would take the water out of it. If you have the gas recombined with oil you are going to get some light ends from the oil back into the gas phase. You may create problems at the temperatures involved. These are some of the kinds of very difficult technical problems that would even be associated with that.

Senator Stevens. I take it, then, that you basically disagree with Dr. Doscher in two aspects. One is in terms of the physical operations of the field during the period of recovery and second you disagree with regard to his conclusion that this two-phased operation would make economic sense in view of the characteristics of the reservoir?

Dr. Koonce. Yes.

Senator Stevens. Thank you, Dr. Koonce.

Senator Hansen. Next to testify representing Sohio/British Petroleum is Mr. E. G. Houlston, manager, reservoir engineering, BP Alaska, Inc., San Francisco, Calif. Am I pronouncing your name correctly, Mr. Houlston?

Mr. Houlston. Senator, it is pronounced H-O-L-S-T-O-N.

Senator Hansen. Thank you, sir.

STATEMENT OF E. G. HOULSTON, MANAGER, RESERVOIR ENGINEERING, BP ALASKA, INC., SAN FRANCISCO, CALIF.

Mr. Houlston. Mr. Chairman, members of the committee, my name is George Houlston. I am the manager of reservoir engineering for BP Alaska. BP Alaska operates in the Prudhoe Bay field on behalf of the Standard Oil Co. of Ohio.

I am here today in response to your request to take testimony concerning recommendations made before this committee on October 12, by Dr. Todd Doscher. My statement today has been prepared to clarify BP/Sohio's position in regard to the points raised before this committee.

Many studies on the Prudhoe Bay field have been performed. Indeed, the claim has been made that this field has been studied more than any other prior to production. In my opinion, the most comprehensive review of the work performed on Prudhoe Bay field was presented by the working interests and the consultants to the State of Alaska, at the conservation hearing held in Alaska on May 5 and 6. Those proceedings are a matter of public record.

The Prudhoe Bay field is estimated to contain some 22.9 billion barrels of stock tank oil in place. By far the most significant portion of this in place oil, some 22.2 billion stock tank barrels, is to be found in the Sadlerochit formation. The other 0.7 billion stock tank barrels are located in the Sag River and Shublik formations which overlie the Sadlerochit. Major geologic faults appear to partition the reservoir between the main area of the field and the west end or Eileen area. The field is thus subdivided by geologic formation and by area.

The main area Sadlerochit contains 21.4 billion stock tank barrels and it is this accumulation which has been the subject of intensive study by the working interests in the field and by other interested parties. It has been estimated that oil reserves of about 8.6 billion stock tank barrels will be recovered from the main area Sadlerochit.

The estimated oil reserves for the entire field amounts to some 9.4 billion stock tank barrels. These include 0.5 billion stock tank barrels of condensate recovered from gas cap gas and 0.3 billion barrels from the Sag River and Shublik formations and the west end Sadlerochit.

Gas cap gas in place in the field amounts to 26.5 trillion cubic feet at standard surface conditions. A further 17.1 trillion cubic feet of gas in place as solution gas. Some 26.5 trillion cubic feet of hydrocarbon gas are considered to be recoverable and 300 to 400 million barrels of gas liquids. The heating equivalent of these reserves amounts to about 5 billion barrels of crude oil.

BP Alaska, acting on behalf of Sohio Petroleum, has viewed production from the field as a matter of maximizing total hydrocarbon recoveries. The studies we have conducted have been aimed toward formulating sound reservoir management policies consistent with that objective. Our studies have concentrated primarily on the main area Sadlerochit reservoir. The oil recoveries estimated in reservoir simulation calculations do not include the 800 million barrels of oil and condensate recoverable from other sources in the field.

The studies we have conducted have included not only reservoir fluid considerations but also other factors which influence reservoir performance such as well density, surface facility operating conditions and capacities, gas lifting or pumping of oil wells, and the injection of gas and water. Ultimate hydrocarbon recovery is the outcome of collectively exercising these development options to varying degrees and at appropriate times through the life of the field.

Based on current reservoir information and proven methods of recovery our studies have led us to a plan of operations which incorporates the following major elements:

1. Production of oil at an average rate of 1.2 billion cubic feet per day increasing to 1.5 billion cubic feet per day when pipeline capacity is available.

2. The reinjection of gas produced in excess of that needed for fuel and sales.

3. The delivery of 2 billion cubic feet per day of sales gas as soon as a gas pipeline and a plant to condition the gas to specification can be completed, currently estimated to be sometime during 1983.

4. The drilling of wells on 160-acre spacing or closer if necessitated by reservoir performance.

5. The reinjection of produced water into the reservoir and the probably supplementing of such water with source water within 7 years from the start of oil production, that is, 1984 or earlier.

6. The installation of lower pressure gathering and separation systems and artificial lift facilities.

7. A very intensive program of reservoir surveillance and testing to compare forecasted against actual performance on a continuous basis.

By implementing this plan of operations it is anticipated that peak production rates from the field could be sustained for 7 or 8 years and deliveries of gas could be held at 2 billion cubic feet per day for about 25 years. In all cases we have studied, oil production declines when gas handling facilities can no longer cope with the gas produced with the oil. It should be possible to manage and operate the reservoir within the framework of this plan to achieve a recovery of about 40 percent of the original oil in place after 25 years and about 72 percent of the gas originally in place over 40 years.

After 25 years of oil production our simulation models indicate residual oil saturations in the original oil column which are mainly in the range of 25–46 percent. Earlier testimony given to this committee to the effect that residual oil saturations in our simulation runs were extremely low, approaching zero, can be categorically dismissed as without foundation and in complete contradiction to sworn testimony presented by BP Alaska to the Division of Oil and Gas Conservation, State of Alaska.

Scope may well exist for improving recoveries by applying methods of enhanced recovery, when such methods have been proven in the field. The plan of operations should not diminish the viability of any such prospective schemes. The working interests will remain continuously alert to all promising schemes for additional recovery.

In developing the present plan of operations, we investigated many variations in oil offtake, gas sales and water injection. In contrast to some opinions expressed, our studies have shown that the timing of gas sales at a rate of 2 billion cubic feet per day affects ultimate oil recovery only slightly. We estimate a possible loss of oil recovery on the order of 1 percent of the oil in place or just over 200 million barrels over 25 years of oil production. Over the same period, more than 12 times the heating equivalent of the "lost" oil could be recovered ment that the sale of gas is detrimental to ultimate oil recovery, is thoroughly misleading when considered out of the context of the level and timing of gas sales, the associated oil offtakes and all the other developments which are planned to promote recovery from the field.

We have tested our plan of operations against oil offtakes of 1.2 to 1.8 billion cubic feet per day and gas sales of 2 billion cubic feet per day and gas sales of 2 billion cubic feet per day starting as soon as a gas line and conditioning plant can be completed. Again, from our studies we expect only slight variations in ultimate oil recoveries after 25 years of production.

At oil offtake rates of 1.5 billion cubic feet per day, we have studied the effects of gas sales at 2.5 billion cubic feet per day commencing as soon as a gas pipeline is available. This resulted in a lower oil recovery of about one and one-quarter percent after 25 years. Using an earlier reservoir description we also investigated extreme cases of no gas sales and sales of 3.5 billion cubic feet per day. In the case of no gas sales, water was still injected though at a lower rate, and recovery obtained was about one and one-half percent higher than with sales at 2 billion cubic feet per day. At gas sales of 3.5 billion cubic feet per day recovery fell by about 5 percent but this run was performed with the same water injection rate as the 2 billion cubic feet per day gas sales rate. A more successful outcome would have been possible but was not pursued. We have concluded that gas sales at 2 billion cubic feet per day should not cause concern in regard to ultimate oil recovery. At this stage, any proposal to sell gas at 2.5 billion cubic feet per day by 1983 we would approach with caution, and we would actually oppose any scheme to sell gas at 3 billion cubic feet per day as early as 1983.

It is recognized that the forecasting of reservoir performance with little or no production history in a field as large as Prudhoe Bay is subject to uncertainty. We have had to rely heavily on our reservoir simulation studies to predict detailed reservoir behavior. However, the experience that has been gained from operating other fields similar to Prudhoe Bay has been especially valuable in assessing the validity of our model predictions. We are confident that our near term assessment of Prudhoe Bay performance is a reasonable one.

Looking to the longer term, in many of the reservoir simulation model runs we have made, the differences in oil recovery arising between hypothetical reservoir management options do not become fully apparent until after about 15 to 20 years of oil production have taken place. There is every reason to expect, therefore, that there will be time and scope to adapt our plan of operations to ensure that hydrocarbon recoveries are maximized. The intensive reservoir surveillance and testing program which we will be undertaking will provide the control information necessary for those purposes.

The working interests in the Prudhoe Bay field have acquired unusually detailed reservoir information prior to production. This has been very fully utilized and very considerable efforts have been devoted to studying the field and developing the plan of operations. Although the results of the studies performed by the working interests are not the same in numerical detail, all the working interests have drawn similar conclusions in regard to how the field should be produced.

Mr. Chairman, I submit that this consensus view is a sound technical basis to support the sale of Prudhoe Bay gas as soon as a pipeline and conditioning plant can be constructed.

Thank you.

Senator STEVENS. Thank you very much, Mr. Houlston.

As Senator Hansen indicated, we have a series of questions for all witnesses. Let me ask those of you first. The President's position assumes that the pipeline's throughput will average 2.4 billion cubic feet of gas per day. What do you believe the average throughput will be over the life of the field?

Mr. HOULSTON. Our plan envisages that the existing or the planned oil production rates of up to 1.5 million barrels per day will insure the 2 billion cubic feet a day of gas sales being maintained for a very considerable period of time, 25 years.

Senator STEVENS. Twenty-five years?

Mr. HOULSTON. Yes.

Senator STEVENS. What oil production would be necessary to sustain that rate?

Mr. HOULSTON. As I have said, sir, the 1.5 million barrels a day average oil offtake should be able to sustain 2 billion cubic feet a of oil production.

Senator STEVENS. Will that rate require early production of the gas from the gas cap?

Mr. HOULSTON. The gas cap production we don't anticipate contributing very largely to gas sales until beyond the first 10 years of oil production.

Senator STEVENS. After that it would require production from the gas cap. The question pertained to early production of gas from the gas cap, do you think that's early production in this field, would you say 40 years producing the gas cap after 10?

Mr. HOULSTON. I don't think it is. It depends, of course, on how one should define "early," but by the earliest possible time at which gas sales could take place, well in excess of 2 billion barrels of oil will have been produced. I don't consider that to be terribly early, sir.

Senator STEVENS. In your report on technical considerations of the Prudhoe Bay unit operating plan which was submitted to the State of Alaska in October of 1976, the oil in place was estimated to be 31.2 billion barrels. Your prepared statement this morning estimates only 22.9 billion stock tank barrels. Could you tell us what the reason for the reduction and estimate of oil in place is?

Mr. HOULSTON. Yes. There is no reduction. The estimation of the oil in place is conducted on the principle of reservoir barrels. There is shrinkage on production of those reservoir barrels. I think you will find, sir, that that is the difference.

Senator STEVENS. You have not reduced your estimates, then, from 1976?

Mr. HOULSTON. No, sir.

Senator STEVENS. In your statement you indicate that the estimated oil reserves for the entire field amounts to some 9.4 billion barrels including .5 billion barrels of condensate recovered from the gas cap. Why do you assign condensate to the oil production when the API estimate of crude production and reserves appear to exclude condensate from all estimates?

Mr. HOULSTON. Perhaps I am not too familiar with the way the API categorized those, sir, but it was my understanding that condensate, being a liquid, would drop out in the oil separators and was classified along with crude oil.

Senator STEVENS. Do you have any studies of the effect of gas sales on oil production?

Mr. HOULSTON. Yes. We have run some studies on the effect of gas sales on ultimate oil recovery. We have found in all cases that the effect has been very slight as my testimony addressed.

Senator STEVENS. On behalf of the chairman of the committee it is his request that he would like to request that the committee be provided with copies of your studies on the effect of gas sales. If that is consistent with your company policy I would like to have it. If not, I would appreciate it if you would discuss it with the committee staff.

Mr. HOULSTON. Yes.

Senator STEVENS. Let me ask a couple of questions about Dr. Doscher's report. Dr. Doscher's report indicates that within 15 years the production rate is down to less than 500,000 barrels a day. Do your studies indicate that also?

Mr. HOULSTON. Yes. The oil production rate does decline and I would say that this is a perfectly normal process.

Senator STEVENS. Are BP's decisions with regard to the oil pipeline and gas pipeline based upon any estimate of future recovery from the Beaufort Sea or any other area of the North Slope?

Mr. HOULSTON. I am not sure that I can answer that point, sir. I am sure that we are hopeful that other sources of oil production will be found.

Senator STEVENS. I am hopeful it would dwarf Saudi Arabia, too, but I am not sure we should base options on hopefulness. I am wondering from company policy if you projected and estimated recovery on other sources on the North Slope?

Mr. HOULSTON. I am afraid I cannot answer that, sir. I am not expert on those matters.

Senator STEVENS. Could you tell me if BP has studied the two-phase flow of gas and oil through the oil pipeline as one option for the transportation of gas for gas sales?

Mr. HOULSTON. No, sir, we have not studied that option in detail. However, I could make some points in relation to that method of transportation. As far as I understand it it would require at each of the pump stations along the Trans-Alaska Pipeline System to recompress gas and reinject it into the line. The line, as I understand it, goes over a number of fairly substantial mountain ranges. In my experience within BP, the problems with transporting a two-thousand mixture in a line of 48 inches in diameter over mountain ranges it is simply mind boggling.

BP's experience at two-phased oil flow is limited to an instance in the Arabian Gulf where I believe the line was 12 inches in diameter. It went through only 26 miles versus the 800 we are talking about. There were very severe operational problems in that line, sir. The irregular arrival of gas and oil made separation virtually impossible at certain rates.

I would ask you to consider that in the Doscher proposal of using taps as a two-phased oil line it would be very, very difficult for any mere mortal to design the full range of operating conditions in the gas-oil ratios, particularly as we have all projected an oil production decline in those phases.

I submit to you, sir, that my company has not done the detailed calculations mainly because we don't know of anybody in the world who has ever faced the prospect of using a 48-inch line in such a mode of transportation.

If I may just express my own professional opinion, and I qualify again it is not with the benefit of very, very detailed work in computer simulation runs, I don't think it it, sir, sound, if you will. That's my personal opinion.

Senator STEVENS. When you interpret the two-phased flow of gas and oil what does that mean to you? It seems to mean something different than it did to me. How would that operate?

Mr. HOULSTON. Well, if our experience in the Middle East was anything to go by, the line would vibrate severely. I would fear for the integrity of it working in that particular mode day in and day out.

Senator STEVENS. What caused the vibration?

Mr. HOULSTON. The different speeds at which the oil and gas would actually physically move in the line. As I pointed out, the mixture would have to climb several mountain ranges and the gas would tend to accelerate on the upgrades and hold up on the downgrades. You would get rather an irregular velocity profile throughout the mixture. This would produce some kind of vibration in the line even beyond safety and environmental reasons. Maybe I am shooting from the hip, but I wouldn't recommend doing it.

Senator STEVENS. This report came up too late to really do anything but raise serious questions. I am happy to have you answer some of them.

What about the problem of the recoverability of oil? I know you mentioned it in your statement. Dr. Doscher projects that the decision with regard to the gas pipeline transportation should be put off for a period of time. I believe he said 5 years, at least, until actual production has been monitored. Are you familiar with that suggestion?

Mr. HOULSTON. Yes, as a reservoir engineer I can't dispute a suggestion of that nature. Surely as time goes on we will learn more and more about the reservoir and presumably be in the best position to optimize and control our future operations but I will say this that it is admirably demonstrated in Dr. Doscher's report that the reservoir engineer's lot is one which has to cope with uncertainty all through the life of a field and I just put forward the suggestion that in 3 or 4 years' time on whatever, however many years time, we will still be faced with a certain degree of uncertainty in matters relating to very long-term forecasts on oil or anything else for that matter in 25 years.

Senator STEVENS. Well, as a reservoir engineer do you think you know enough about the reservoir to project sufficient data to make the decision now to proceed with a gas pipeline of such cost?

Mr. HOULSTON. Well, let's put it this way, sir, we have tried to give Prudhoe Bay field the best physical we know and all of our studies point toward being able to make the kinds of projections that I have presented before this committee in my testimony. We are reasonably confident as far as we can tell that it should be possible to operate the field along the lines that we have indicated and to achieve the types of recoveries that we have spoken to.

Senator STEVENS. And BP on its behalf and the behalf of Sohio supports the authorization for the construction of the pipeline?

Mr. HOULSTON. Yes, we see no technical reason why it shouldn't go ahead.

Senator STEVENS. Thank you very much.

Do you have any further questions?

[No response.]

Senator STEVENS. Thank you very much. I appreciate your candor.

Dr. Doscher, I find myself in an enviable position of being a member of three other committees each of which is meeting at this time so I am here and happy to have you here, Dr. Doscher. Do you want to proceed with your statement?

Dr. DOSCHER. I think so.

STATEMENT OF DR. TODD M. DOSCHER, PROFESSOR OF PETROLEUM ENGINEERING, UNIVERSITY OF SOUTHERN CALIFORNIA, LOS ANGELES, CALIF.

Dr. DOSCHER. At the time I was requested to appear before you on October 12, I informed you that my professional attention, and that of my colleague, Dr. Elmer Dougherty, Jr., was brought to bear on the

Prudhoe Bay oil field because we were retained by the Legislative Affairs Agency of the State of Alaska to assess the operating plans that were submitted to the State's division of oil and gas.

You are apparently here concerned with one of the conclusions which we reached in that study. We believe it is necessary for you to assess this one conclusion concerning gas sales within the total framework of our study.

Our overall conclusion is that studies prepared by the operators on the field, and those prepared on behalf of the division of oil and gas, as well as those prepared by still other groups have not been juxtaposed, scrutinized, and challenged well enough for an unequivocal decision to be reached at this time as to what is the best operating plan for Prudhoe Bay. Certainly not to the extent as I and my colleague would have done had we been given the responsibility to do so.

Of course, a definition must be given to the best operating plan. The best may be variously defined as the best for maximizing the immediate flow of royalties and taxes to the State, or for maximizing the profitability of the operators, or for maximizing the recovery of crude oil, and the maximum flow of benefits to the people of Alaska.

Our studies explicitly used these two yardsticks for defining best: the maximum recovery of crude oil, and the maximum flow of benefits to the State. We were retained by the State of Alaska.

It is always a goal of the reservoir engineer to maximize the recovery of crude oil. At this time the need for attaining such a goal is intensified by the fact that our Nation's access to supplies of crude oil is sorely limited and the limitation increases daily. The National Petroleum Council's prediction of future supplies of crude oil in the absence of Prudhoe Bay and new discoveries is shown in their figure 5 of their December 1976 study. America's supplies will have dwindled to less than 1.5 million barrels a day by 1990, and even with Prudhoe Bay will be only 2 million barrels a day. Compare this with the 8 million or so we produced last year and the 20 million barrels we burned each and every day. It will be a stroke of sheer luck to be able to double this rate by successful exploration and enhanced recovery. A Prudhoe Bay field discovered every other year would just keep our supplies constant if we could continue to import oil.

We must also look forward to severe limitations with the coming decade of our ability to import crude oil. The oil in the subsurface of the Mideast is limited too by Nature, and production will surely peak within the decade ahead. Our basic yardstick, therefore, of assessing whether the proposed operating plans for Prudhoe Bay will maximize the recovery of crude oil is well justified. We concluded that the evidence for the claim that gas sales from Prudhoe Bay would not interfere with maximizing crude oil production is weak. We believe the evidence for reaching such a decision will not be available for several years during which time reservoir surveillance will provide the required data.

It is to be noted that the Prudhoe Bay field is so large that a mere 1 percent difference in recovery efficiently amounts to a volume of oil that is produced from some very large oilfields. So large, in fact, that less than a handful have been discovered in the United States since 1960. Whereas in former times one could be sanguine about sacrificing a percentage point in recovery efficiency for greater convenience, a smaller investment, or somewhat higher profitability, the same standards can no longer be applied.

Further, by conventional technology some 12 billion barrels of crude oil will not be recovered from Prudhoe Bay. It is folly to adopt an operating plan that doesn't consider the possible effect of such a plan on the potential implication of tertiary recovery processes that may succeed in capturing some of that 12 billion barrels of oil that will remain in the largest reservoir ever to have been discovered within the United States.

So much for our first yardstick.

Now, for the second: the maximum flow of benefits to the State of Alaska. We concluded that this matter had not been given the attention it merits. We do not believe the sale of gas is in the best interests of the State or the Nation, that is, the sale of gas now envisioned.

It will be impossible to sell more than 2 billion cubic feet of gas a day without seriously hurting the crude oil recovery even using the optimistic analysis of the operators therefor. A daily sale of 2 billion cubic feet a day through a pipeline that might well represent an investment of $25 billion, which we have observed in the literature, will require a transportation tariff of some $5 per thousand. This in itself, the transportation cost, is so much greater than current pipeline delivered costs for natural gas, and so much greater than those envisioned by any proponents of deregulation that the wellhead price of gas itself will be pushed back to marginal values. The State will reap but a fraction of the value of the gas.

There is also a major question as to whether the gas will be marketable, on the proposed schedule, unless the price of all other gas supplies are raised to its equivalence.

The State would gain much more from their resources by ultimately converting a significant amount of the gas to liquid fuels, alcohols, and petrochemicals. The State could envision starting gas movements in the present crude oil line within 15 to 20 years. Certainly, there are problems in using the present line for gas and oil flow, but there is a lot of money available to study these problems. Our technology should be used to its fullest to seek optimum use of these facilities. The Prudhoe Bay reservoir is a short lived reservoir. Within 8 years oil production will start a precipitous decline, when our needs of additional liquid fuels will be verging on the desperate, and within 15 years its potential will be less than 500,000 barrels a day.

The State could envision a long future of profitable and valuable utilization of its gas resources for over a century, particularly if such use is combined with utilization of its coal resources, should it not consent at this time to gas sales. The Nation would be little the worse for not having the Prudhoe Bay gas available for immediate burning. It will amount to less than 5 percent of our current consumption. An equivalent amount of gas could probably be made available from other sources, far cheaper and within the same time framework, if exploration and production of marginal sources in the lower 48 were promoted by trivial increases in regulated prices. This would be true for a decade or two, but for longer periods of time you must address more fundamental issues.

There is the possibility of converting the gas to methanol on site. The line does have a potential for taking the gas out in one form or another. The Prudhoe Bay, as you have heard many times this morning, is a short lived reservoir. It doesn't matter that it is a normal decline. The fact is that it is a precipitous decline and in some 15 years a 500,000 barrel a day reservoir. The State could envision a long future of profit and an available gas resource for over a century, particularly if the use is combined with the utilization of its coal resources.

That's my statement.

Senator STEVENS. Dr. Doscher, you heard the testimony of the mind boggling problems, as you mentioned too, of the 48-inch line on the two-phased oil and gas transportation system. Do you concur that there are such problems?

Dr. DOSCHER. There are problems, but I don't believe that they cannot be overcome for the amount of money that is available and in the interest of the State of Alaska.

Senator Stevens. From the point of view of your report to the Legislature you did not discuss any question of maximizing the production of gas?

Dr. DOSCHER. No, I did not discuss that. I don't think there will be any problem. The best way to maximize the production of the gas is to stay with it over a long period of time, because if you are merely interested in gas production you can operate the reservoir to very, very low pressures and recover a tremendous fraction of the gas.

Senator STEVENS. Do you know of any place in the world where the two-phased system that you suggest has been used effectively?

Dr. DOSCHER. No, sir.

Senator STEVENS. Has there been any computer model of it to demonstrate that it could be used?

Dr. DOSCHER. Not to my knowledge.

Senator STEVENS. Have you run any computer analysis of your suggestion?

Dr. DOSCHER. No, sir, no.

Senator STEVENS. You tell me that the report that I have is in draft form and it has a caveat on it from Gregg Erickson the director of research of the State's Legislative Affairs Agency, that indicates that it does not represent the view of the Alaska Legislative Affairs Agency, and that the final form of this report will be available later this month or early in November. Are you revising that or are they revising it?

Dr. DOSCHER. No. The only revisions that we will do will be correcting typographical erors and the caveat, I think, is proper. We actually put that on because it is our report and we did not discuss it with the Legislature to get their approval. It was our report in satisfying a contractual obligation to the Legislative Affairs Agency.

Senator STEVENS. Incidentally, Dr. Doscher, I made sort of a flippant comment the other day about politics. I want you to know I did not imply that you were involved in any kind of a political foray here.

Dr. DOSCHER. Fine. I understand and appreciate that very much, Senator.

Senator STEVENS. Your colleague in the study, Dr. Dougherty, does he agree with your comments?

Dr. DOSCHER. Yes.

Senator STEVENS. Do you stand by your recommendation to the committee that no action be taken on this proposal by the President?

Dr. DOSCHER. I do, sir.

Senator STEVENS. I want to ask you the other side of the question I asked the other witnesses. Have you assumed in your judgment that there will be no future discovery from the Beaufort Sea at the North Slope?

Dr. DOSCHER. I don't assume either way. I say with any exploration, based on the current history of the United States and overseas, that the chances are not good for future discoveries and that should additional discoveries be made, and I hope they are made, then we should attempt to keep our plans flexible enough so that we can encompass some limited amount of Beaufort Sea production in the current line. Again, this speaks for delaying any decision that closes off options until we have more time to actually see how this reservoir performs and to see how well our luck is in discovering new reserves in the Beaufort Sea or in the Brooks Range.

Senator STEVENS. You established one technical question. You point out that Mr. Houlston of BP testified that saturations in the operations simulation runs were extremely low, approaching zero. He stated this was not correct. What did you base your assertion on in that?

Dr. DOSCHER. I believe that either I left out a sentence or maybe in the transcript—I will take responsibility for it. But when I was addressing this to the Senator from Oklahoma at the last meeting I was talking about the relative permeability curve which shows, for example, in the Van Poollen study, a residual saturation of oil of 32 percent to gas is assumed in the model.

In the operating model, at least the one which we were given most access to, the residual oil saturation goes to very low values approaching zero. As a result of this difference the saturations of oil in those elements of the reservoir which are invaded by gas to get to values in the teens in the results we were shown which is a very, very low residual to a gas drive and this is one of the problems with using a simulator.

You see this information is given to the simulator and the simulator can't do anything but respond to it. So, therefore, the results which come out of the simulator rely on this particular input. If this particular input turns out not to be correct then the simulator is not predicting reality and this is one of the major problems we have. We are not at all certain of the validity of the input into the simulator.

Senator STEVENS. The basic bottom line of your recommendations to the State legislative committee would be that plans should be developed to utilize the gas production from Prudhoe Bay in Alaska and that we export only the oil, is that correct?

Dr. DOSCHER. And gas products. For example, you can make methanol out of the gas which can serve as a fuel directly or revaporize as methane at its port of entry for making petrochemicals. In other words, the State should essentially assess what of Prudhoe Bay can be used in the next 100 years to make the State a thriving community with a positive base of resource and then once it has done that to assess what it has left over for export as ordinary gas. And I have a hunch that the State could well use most of the gas resources and convert it to very useful products for America and for the world. It is a gold mine. Gas, in my mind, should not be burned. It is too valuable a resource. It has been wasted on many occasions. There are other fuels which can be used for mere burning. A valuable resource you buy such as methane should be converted to the host of petrochemicals, medicinals, and special liquid fuels that gas and only gas can serve as a prime material for.

Senator STEVENS. Aren't you, in effect, asking the State to use its authority under the Conservation Statutes to, in effect, deny the producers the right to sell the gas that they produce?

Dr. DOSCHER. Well, the State could be the purchaser.

Senator STEVENS. That would be mind boggling.

Dr. DOSCHER. It could be. But I realize there are many mind-boggling things, but the situation with respect to energy in our Nation is such that we have to face up to mind-boggling things to insure that we survive another century or so.

Senator STEVENS. One last question. In your studies did you do any economic studies of the energy loss in converting to methanol for instance?

Dr. DOSCHER. No, sir. Our study was very limited. It was to assess the plans and give recommendations.

Senator STEVENS. Thank you very much.

Mr. Chairman, it is nice to have you here.

Senator DURKIN [presiding.] Are you ready for comments?

Senator STEVENS. Right behind you.

Senator DURKIN. Dr. Doscher, I have some questions of the other witnesses as well.

Senator STEVENS. Would you let me interrupt? I forgot to ask Mr. Gore, John, do you have any comments to make or were you just there to answer questions?

Mr. GORE. No. That's all right.

Senator STEVENS. That's Mr. John Gore.

Senator DURKIN. We have four or five hearings at once and none of us have the gift of bilocation or trilocation. I will apologize for being late, but submit the question for the State of Alaska, for Exxon, BP and Arco, to Mr. Van Poollen and Mr. Houlston and hopefully we can get an early reply. You can get a copy of the questions from the reporter.

Where did Dr. Doscher go?

Senator STEVENS. Dr. Doscher has a couple of questions.

Dr. DOSCHER. Sorry.

Senator DURKIN. No problem.

Again, Dr. Doscher, I want to thank you for both appearances here. Many of us have concerns, I think the real question is are we jeopardizing that source of oil supply to Alaska and to the lower 48 and I think we have to resolve that question to the best extent possible because we just can't suffer a loss of 4 to 6 billion barrels of oil in today's world condition especially when our balance of payments is so far out of whack buying OPEC oil.

Dr. Doscher, when you began working on your report with respect to Prudhoe Bay Field did you expect to have access to the operator's proprietary information?

Dr. DOSCHER. We were not sure of it. We told the State when we were preparing the contract with them that if we had access we should envision the probability that they would ask for a secrecy agreement and the State agreed to permit us to sign secrecy agreements with the operators in order to have access to any information they would like to show us.

Senator DURKIN. So, in response to a question did you get access?

Dr. DOSCHER. I would say we had good access. I wouldn't say we had complete access. That is, I don't know whether we had complete access. The situation was such that we had to ask for what we wanted and when we asked for it I would say in 80 percent or 90 percent of the cases we got what we wanted, but nothing was laid out on the table without our asking for it. But when we did ask for it we got it in most cases.

Senator DURKIN. Do you think you have had access to adequate information?

Dr. DOSCHER. I think it was adequate to tell us what the methodology was and as I say one of the critical aspects here is the assumed residual saturations which really govern the entire concept and the entire ultimate behavior of the reservoir and this was given in the hearings at Anchorage to a limited extent and we chased it down in our discussions with the operators and that's the thing of utmost importance here, what was the assumed residual oil saturation.

Senator DURKIN. With respect to the proprietary information did I understand that the State Division of Oil and Gas has—did you get access?

Dr. DOSCHER. No. There was a little more limitation there because when we asked for things quite frankly we got them but several pages were omitted. It was a little more difficult getting free access to that information and their problem was that the information was given to them originally under secrecy agreement according to some charter or some rules or regulations to the State so they had a problem in deciding what they could release to us, but that was a little more limited.

Senator DURKIN. Do you think that access to that proprietary information would have enabled you to more thoroughly evaluate the data and the operating plan?

Dr. DOSCHER. I really don't think so. Again, I will come back to the fact that the critical facts we have found are the things that were influencing the results of the operator and of Van Poollen and Associates is what their input to the model was and it was this input, as I say, that in our estimation is not certain information. It is presumed correct and within the possibility that that input can be in error to some extent then the results of the simulation can be in error.

The other thing that we encountered, and this is what anyone would encounter, that as you study the runs which were made public, that is the various runs, there was not a complete consistency between the runs so that, in other words, one parameter and only one parameter was not varied at a time. So it was in some respects impossible to say what the reference case was to which you were comparing the preferred scheme that the operator set forth. So this, of course, was beyond us to do. We did not have the ability at all, nor were we given the job to run additional cases to round out or complete the evaluation of the various parameters.

Senator DURKIN. Last May I understand there were hearings in Anchorage. Do you feel that those proceedings were adequate in terms of verifying the various discrepancies and consultants' work?

Dr. DOSCHER. No. We mentioned that in the report. We do not think the presentations were given the scrutiny and the juxtaposition that they merited. For example, the Van Poollen report on behalf of the State and, for example, the report prepared by Core laboratories for the Alcan Pipeline people showed a very significant effect, a trend was established to show a very significant effect of gas production on oil recovery and this was not raised at least in the public session. It was not raised to our knowledge in saying to the operators, well, now how do you account for this?

Now, certainly, there is a complete difference in sophistication in the two sets of models but nevertheless the fact that the trend of losing oil as the function of the gas sales were so strong in the Core laboratory's study and fairly strong in the Van Poollen study and seemed to be completely not present in the limited number of runs that were presented for the operators that if it were my responsibility, as I said this morning, if it were the responsibility of my colleague and myself we would have essentially challenged it and juxtaposed the various things and asked for additional fill in runs. We would have done that.

Senator DURKIN. Excuse me. We are operating under a time constraint. I apologize if I am asking questions that were answered earlier. But I doubt if you have highlighted either in testimony this morning or in the report to discrepancies which you found to be most important.

Dr. DOSCHER. Right.

Senator DURKIN. In your opinion what is the tertiary recovery potential at Prudhoe Bay?

Dr. DOSCHER. We do not know that there is a tertiary process that will work. We are engaged in a lot of tertiary work in this country today but we do know something about the tertiary recovery techniques that might be used and, for example, in the case of carbon dioxide one would want to have a very high pressure in the reservoir. There, until we feel, until it is established that carbon dioxide is or is not useful we feel that every attempt should be made if it doesn't interfere with something else dramatically to maintain a high pressure in the reservoir until such time as we can say, yes, this is applicable or no, it is not.

The thing is we talked about tertiary recovery is getting another 10, 20 or 30 percent of the original oil in place out of the reservoir and in the case of Prudhoe Bay 10 or 20 percent can be a lot more oil than we will discover in major fields in the next 10 years by primary exploration. So, in other words, the tertiary recovery prospects from Prudhoe Bay could well be the second largest field ever to be discovered in the United States. It is numbers like that that one has to bear in mind.

Senator DURKIN. Dr. Doscher, have you described what you would consider the optimum rating plan that would maximize the oil recovery and the gas recovery——

Dr. DOSCHER. No, we certainly have not and we see nothing wrong with the plan for the first 5 years. The only thing we are calling attention to is the question of committing an investment that could be $15, $20 or $25 billion because once that is committed you have closed the option of doing anything but selling the gas because with a commitment like that on the ground there is no two ways about it, the gas is going into that pipeline. So this is the only conclusion we have really with respect to the gas line, is that we think the commitment should not be made at this time. If it were our money and our decision we would wait a couple of years, see how the reservoir performs and the Beaufort Sea and see what the other possible end uses were for the gas and then make the decision at that time.

Senator DURKIN. I believe earlier you suggested that we wait 3 years.

Dr. DOSCHER. Two to five. It depends on how readily the information is—how definitive it is, whether it is in a gray area or whether it is truly clear cut.

Senator DURKIN. In other words, you sort of feel that we are in somewhat the same position as the blind man feeling the elephant and not knowing what we are up against and needing more time to avoid a potential catastrophic loss?

Dr. DOSCHER. I will agree with that. I think that there is more time needed and there is not enough to be gained, as I pointed out, by hastening the construction two or three years earlier because it is only going to be 5 percent of our supplies and this will not, in itself, be a do or die thing for America.

Senator DURKIN. You state in your report that the reliability of the data which was used to develop the permeability data by the operators was not established in the technical literature.

Dr. DOSCHER. I think you are talking about the use of the centrifugal technique to determine residual oil saturation. This, as I say, this is the way they got very low residual oil saturations to gas and although this is a method that comes to mind and it is a good idea, there is no verification that the time scaling in the centrifugal operation is equivalent. At least I see no proof in the literature that it is equivalent to the real world of reservoir operations.

Senator DURKIN. Could you, if you haven't already, submit for the record your explanation of how the permeability may affect production as proposed and, you know, your view of the assumptions made by the operators in devising the current operating plan. You may have already done that.

Dr. DOSCHER. I may have mentioned it. For your benefit let me say again, whereas in the Van Poollen study an end point saturation of 32 percent is assumed, that is the lowest value to which the oil can be driven by expanding gas. In the case of the operators this was not assumed to be an end point saturation but that the saturation would gradually become smaller and smaller and smaller and this, then, in the computer model lets you get a saturation below 32 percent in the elements of the reservoir that are swept by gas.

Senator DURKIN. I believe this has already been covered, projected differences in the saturation between the operators and Van Poollen seem to be crucial in determining a preferred operating plan. We would like, if we don't already have it, the basic differences in these two estimates and how they compare with operating experience and conventional geological wisdom.

Dr. DOSCHER. Well, I think we mentioned most of it and I will just elaborate on the last one which we again cover in the report. We tried to find evidence for such low residual gas saturations in the literature and such high recovery efficiencies by gas expansion and gravity drainage and we were not able to unequivocally find confirmation of that in field case histories reported in the literature.

Senator DURKIN. Ted, if you don't have any objection, it may have have already been done, I would like to insert the GAO findings which state why current geologic wisdom would indicate that GAO supports Dr. Doscher to a considerable degree.

Senator STEVENS. I think that should be inserted. [See p. 340.]

Senator DURKIN. I would like to point out that they will be made available momentarily and I think if the producers or operators differ with the findings I would urge you to get your differences in the record just as soon as possible.

Dr. Doscher, I gather that—you know we hear a lot about Mexican gas and Mexican gas can be here in the lower 48 or upper 48, if you will, as early as 1979, that the Mexican gas can be piped into the pipe network that exists coming out of the basin and spreading all across the country. Have you given any consideration to us rectifying the gas shortage problem by relying on the Mexican gas for the next few years while we are waiting to see if your conclusions are borne out?

Dr. DOSCHER. I don't think, sir, that you have to rely on Mexican gas. I think that there is probably, as I said both last time and this time, that there is probably enough gas to be found in the lower 48 by a small increase in regulated prices or by deregulation.

Senator DURKIN. I am afraid that it is going to be a big rather than a small increase in price.

Dr. DOSCHER. Well, modest compared to the price of Prudhoe Bay gas. You would have to say based on anticipated price of line costs that it is smaller.

Senator DURKIN. So I gather the bottom line as far as you are concerned is that the Mexican gas may help, may come on the line sooner, but it is your feeling that there is enough gas in the lower 48 that we should not hazard the Prudhoe Bay oil reserves by committing so much gas to the Alcan Pipeline?

Dr. DOSCHER. Within the time framework and the costs that you are talking about, yes. But obviously we have a slight difference on what deregulation means, but I believe that there is significant additional gas or small increments of gas, much smaller than the increment required for delivering Prudhoe Bay gas.

Senator DURKIN. So you think that if we move now not only will we jeopardize up to 6 billion gallons of oil in the Prudhoe Bay Field but we also might well end up with a gas pipeline that tremendously increases the cost of the delivered product to the lower 48?

Dr. DOSCHER. Yes.

Senator DURKIN. I am not sure what the extent of the law is with respect to the President's authority but I gather that assuming for the moment that the President has authority to withdraw the proposal that he sent to Congress that you would recommend that President Carter withdraw the proposal and if he doesn't have authority to withdraw it that Congress turn down the proposal at this time?

Dr. DOSCHER. That would be my recommendation.

Senator STEVENS. I have got to be a little facetious with you and say that I hope that Mexico doesn't have a Dr. Doscher because I am not sure we are going to get any gas.

I am informed that this is probably the last hearing that depends on the committee's reaction to the GAO staff analysis and I am not a member of the committee. But assuming that this is the last time we are going to be conducting hearings in this matter, I want to urge the witnesses that are here today and those on behalf of the State and Dr. Koch, Dr. Koonce and Mr. Houlton for BP and yourself, Dr. Doscher, to submit any comments you have for the record on the GAO comments as I think we should have a complete record by the time this matter gets to the floor.

For myself, Mr. Chairman, I have got to disagree with you. I think we have before us a recommendation from the President on the act that we passed that is another step in the procedure towards authorization of the gas pipeline. Even after we approve the President's recommendation the matter still has to have further, as I understand it DOE investigation and above all it has got to stand the test of the crucible of financeability in the marketplace.

I think Dr. Doscher's comments reinforce my position that this is no investment for the State of Alaska. It is not one we should be forced to participate in and I disagree with the President in that regard in terms of his assumption that the State of Alaska should participate in financing. I think that the ultimate test of the Alcan line will be in the marketplace if the financing institutions of the United States and of the world finance market have confidence that the gas will be there and it will be producible and transportable according to the plan that is set forth in the Alcan application, then I think that the money will be forthcoming and the line will be built and the problems that Dr. Doscher foresees will be, in effect, not answered but countered by the effects of private financing.

If the private financing is not available we will have to come back to the Congress in any event to resume the consideration of how the line will be financed and at that time perhaps should that occur which I don't predict, then I fervently hope it does not occur, but should that occur then obviously the question of using any form of public revenues from the Federal source, and as far as I am concerned, certainly would be applicable to using any public revenues to the State of Alaska, would require a deeper examination into the Doscher position by the Congress or by the State legislature.

But right now it seems to me that that's a matter for the private marketplace assuming that all of the impediments to financing are resolved in terms of securing the permits from the National Energy Board of Canada and from the Provinces and Provincial Treaty and Provincial commitments to right-of-way charges and other Provinces of Canada. But I think we have no alternative but to approve the President's recommendation because should there be further discoveries on the North Slope and Beaufort Sea and we are all aware that there is drilling going on out on the Beaufort Sea by the Canadians at this time, I think that we would face the question of construction on the second pipeline in any event, Dr. Doscher. So it seems that we should proceed with the consideration of the President's recommendation in my opinion and as I said, I am hopeful the committee will consider it and will report it so that we can act on it this year.

I appreciate your comments and I recognize that there has been a substantial question raised but, again, I think when we are talking about this kind of money, particularly if it does not involve a Federal guarantee and does not involve forced participation by the producing companies, then the pipeline entity has a great burden and that's the burden of securing financing. That's the question. If the finance world believes you have raised considerable questions that would put too great a risk involved in this project, Dr. Doscher, then we will hear about it, I am sure, in the long run.

Senator DURKIN. Thank you. My concern and I think the concern of the committee—and that's why I appreciate so much Dr. Doscher's contribution—my concern is that we could well lose up to 6 billion barrels of oil that is needed, needed in the lower 48. We have the pipeline proposal that is in conference now, the energy conference, to get some of the oil to my neighbors in the Northeast.

I supported the Alcan proposal because it seemed to make more economic sense than the others, but I am afraid you might end up with gas at $4 or $5 or even more an MCF, or I am afraid or concerned that we might run into problems with financing. I think that was one of the advantages of the McMillan proposal all along. That does not contemplate a tariff as some of the other proposals did, and I am concerned that the pipeline may be 2 or 3 years or a year or so into construction and then Dr. Doscher could be proved to be clairvoyant, then we have the high-priced gas, we lose the oil, and then we are going to be faced with either a tariff or a Federal tax phase to pick up the tab to complete the pipeline, and with all that might not get the gas as well as losing the oil. That is my concern and I am not sure. It is always easier to state the problem than provide the conclusion and the answer. But those are the concerns that I have and those are, I think, the concerns that the committee and ultimately the Congress is going to be faced with in between Russell's tax proposals and what have you.

Senator STEVENS. Mr. Chairman I think it should be determined how long this record is going to stay open. We know we are only going to be in session now until November 3d or 4th. It would seem that we ought to have at the most a week's delay on this record. I think that's excessive. I would hope the committee would notify all concerned to have whatever submissions they wish to make to the committee by next Monday.

Senator DURKIN. Yes, I talked to Scoop and I am not in the habit of making decisions for Scoop, but my suggestion would be—

Senator STEVENS. You leave then and I will make it.

Senator DURKIN. OK. What I was going to suggest was maybe Friday and then knowing the mail delivery service they will probably get here by Monday. So I really urge, and the Chairman may well overrule me, but I would urge that anyone that has any information that they think this committee should consider should start working on it about 10:40 today and get it in here just as soon as possible. We would like to hold the record open until Monday. The Chairman may extend that and I will see him at the Energy Conference, but I think it is imperative that you get any remaining statements or supporting statements or what have you in.

I think we should point out that the GAO staff report is a preliminary report and if they were settled with a lack of adequate information as well, I think this is the case where haste is in your best interest. With the schedule on the floor no one knows how long we are going to be around here. I think we are going to be here until New Year's Eve trying to work out that Energy Conference.

So, if there is nothing else, Doctor, again I want to thank you and the other witnesses.

[The report referred to follows:]

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

October 19, 1977

The Honorable Henry M. Jackson, Chairman
Committee on Energy and Natural Resources
U.S. Senate
Washington, D.C.

Dear Senator Jackson:

Enclosed herewith is a copy of the report by Professors Doscher and Dougherty which you requested in your telegram of October 12th. Senator Chancy Croft, the legislator responsible for the contract under which this draft report was prepared, has authorized its release to you on the condition that it be considered an internal U.S. Senate document and that its use be restricted to senators and senate staff until 12:00 noon Alaska daylight time, October 20, 1977. This will provide Senator Croft time to distribute the report to the appropriate legislators here in Alaska. We trust this condition will not present you with any difficulties.

Please note that this is a draft, albeit a second one, and that it does not necessarily represent the views of the Alaska State Legislature or the Legislative Affairs Agency. We contemplate that the report will be prepared in final form later this month or early in November, and will make a copy available to you at that time.

Warmest regards,

Gregg K. Erickson
Director of Research

Enclosure
cc: The Honorable Chancy Croft
GKE:dh

DRAFT

REVIEW AND ANALYSIS OF THE PROPOSED OPERATING PLAN AND OF THE STUDIES AND COMPUTER SIMULATIONS OF THE DYNAMICS OF THE SADLEROCHIT RESERVOIR

PREPARED UNDER CONTRACT TO THE
LEGISLATIVE AFFAIRS AGENCY OF THE STATE OF
ALASKA

TODD M. DOSCHER AND ELMER L. DOUGHERTY, JR.
LOS ANGELES, CALIFORNIA

~~SEPTEMBER~~ 1977
OCTOBER

Todd M. Doscher

Todd M. Doscher is Pahlavi Professor of Petroleum Engineering at the University of Southern California, Los Angeles, and a consulting petroleum engineer. He is licensed in the states of California and Texas and the Province of Alberta, Canada.

Dr. Doscher was formerly consulting petroleum engineer to the Exploration and Production Department of a major, integrated oil company. He has over thirty years of experience in petroleum production operations, research and development activities, and in the evaluation of energy and mineral resources. His work has ranged from reserve audits to economic feasibility studies, the development of field operating practices, the invention of specialized drilling fluids, and the logistics of capping gas well blow-outs.

Among other achievements he developed the membrane filter, now in world wide use, for the evaluation of water quality for subsurface fluid injection and was Division Engineer in charge of the development of the first in-situ process for recovering the Athabasca Tar Sands. He has been chairman of the American Petroleum Institute's subcommittee on crude oil recovery efficiency and was the first chairman of the Implementation Committee of Society of Petroleum Engineer's Improved Oil Recovery Field Reports. He was a Distinguished Lecturer of the Society in 1976-77.

Dr. Doscher has been elected to membership in the honorary societies of Phi Beta Kappa, Sigma Xi, Tau Beta Pi and Phi Lambda Upsilon for his achievements in a variety of scholastic disciplines. He holds a bachelor's degree, summa cum laude, and a master's degree in chemical engineering from the College of the City of New York and the Case Institute of Applied Sciences, respectively. He also has a doctorate in colloid chemistry from the University of Southern California.

Elmer L. Dougherty

Elmer L. Dougherty, Jr., is Professor of Petroleum Engineering at the University of Southern California at Los Angeles and a consulting petroleum engineer.

Prior to joining the faculty of the University of Southern California in 1971, Dr. Dougherty was employed by several major U.S. petroleum and chemical companies. His work included refinery chemical engineering, reservoir engineering and directing operations research efforts. In addition, Dr. Dougherty has served in senior management capacities with two firms in the management consulting and computer software fields.

Dr. Dougherty's work has been widely published in the fields of petroleum engineering and operations research. In 1964 he received the Cedric K. Ferguson Medal, awarded by the Society of Petroleum Engineers for the best paper by a junior member. Some of his work includes "Simulation of Oil Reservoirs on a Digital Computer", "A Computerized System for Planning Major Investment Decisions in Oil", and "Optimizing the Scheduling of Oil Field Development". He has also given several papers in the area of statistical and mathematical analysis of oil lease bidding.

Dr. Dougherty is a member of numerous professional associations, including the Society of Petroleum Engineers, the Society of Petroleum Well Log Analysts and the Operations Research Society of America. He is also a member of the professional honorary societies Sigma Xi and Tau Beta Pi. Dr. Dougherty holds a Bachelor of Science degree in Chemical Engineering from the University of Kansas, and has received his masters and doctorate degrees in Chemical Engineering from the University of Illinois.

DRAFT

TABLE OF CONTENTS

			Page
Chapter I		Introduction	1
Chapter II		Major Observations and Conclusions	2
Chapter III		Porosity, Oil Saturation and the Oil in Place	8
Chapter IV		Reservoir Permeability, Configuration, and Recovery Mechanisms	12
Chapter V		Percent Recovery Estimates and Computer Simulation Models	27
Chapter VI		Accumulation of Reservoir Data, Performance of Reservoir Tests, and Surveillance of Producing Operations	42
Chapter VII		Conclusions	47
	1.	Concerning the adequacy of the review of the operating plans submitted by the operators and the studies prepared on behalf of the Division of Oil and Gas of the State of Alaska.	47
	2.	With respect to the staffing of the Division of Oil and Gas of the State of Alaska and other agencies of the state that will be required to maximize the wealth of Prudhoe Bay for the citizens of the State of Alaska.	49
	3.	With respect to the State's evaluation of ways and means for maximizing their interests in the wealth of Prudhoe Bay on behalf of their citizens.	50
	4.	With respect to the research and development programs to increase the recovery efficiency beyond that attainable by conventional technology.	52
Appendix		The Mechanics of Oil Production	55

DRAFT

PREFACE

The authors of this study wish to express our appreciation to the Legislative Affairs Agency for the confidence and trust they put in us in executing this study of the State's most important physical resource, the Prudhoe Bay Oil Field.

For the purpose of executing this study, we have relied heavily on published information in the public domain. In addition, we contacted the operators of the Prudhoe Bay Field, the Division of Oil and Gas of the State of Alaska, and the Division's consultant, H. K. vaN Poolen and Associates, as well as other engineering firms which, for one reason or another, had prepared analyses for the prediction of performance of the Prudhoe Bay Field.

As a requirement for technical discussions with their engineering staffs, the operators requested, and we executed secrecy agreements with the operators, in accordance with approval from the Legislative Affairs Agency.

We intentionally did not overreach what we believed were the limits of our privileges and the necessities for information under our contract to the Legislative Affairs Agency. Therefore we may not have delved into certain details that we believed were proprietary and would ADD little to our conclusions. Our primary attention was to the methodology employed in the performance predictions and to the source of the input data. The agreed-upon remuneration for our services also posed limitations on the pursuit of overly detailed examination of documents and conference follow-ups. Again, we believe such additional examinations would not have any significant effect on our conclusions.

DRAFT

Chapter I

INTRODUCTION

This study was prepared in accordance with an agreement entered into by the Legislative Affairs Agency of the State of Alaska and Todd M. Doscher and Elmer L. Dougherty, Jr.

The purpose of the agreement is to provide, through the Agency, professional consulting services in oil and gas reservoir analysis to the Alaska State Legislature.

The statement of work, parts (A) and (B), of the agreement follows:

> (A) The Contractors shall provide a written review and analysis of the proposed Prudhoe Bay operating plan, and the studies and computer simulations that have been made of the dynamics of the Sadlerochit Reservoir, including the studies made for the Alaska Department of Natural Resources by H. K. Van Poolen and Associates, Inc., and for the U. S. Department of the Interior by H. J. Gruy and Associates. In addition, the Contractors shall contact the principal owners of leasehold interests in the Prudhoe Bay Field and obtain from them such information as is relevant to this analysis and as the owners may be willing to release to them.
>
> (B) The purpose of the written review and analysis shall be to provide the legislature with an independent audit of the practical and theoretical implications of the reservoir operating plans that have been and may be proposed by the field operators and the Alaska Department of Natural Resources.

Todd M. Doscher and Elmer L. Dougherty, Jr., the contractors, ~~for this study~~ herewith submit the attached report in fulfillment of the agreement to provide the specific services requested.

The contractors are individually responsible for the opinions, interpretations and findings that are presented in this report. The opinions, interpretations and conclusions are not necessarily shared by the Legislative Affairs Agency of the State of Alaska, nor by associates, clients and employers of the contractors.

Chapter II

MAJOR OBSERVATIONS AND CONCLUSIONS

The dynamics of a petroleum reservoir are a function of 1) the physical and chemical characteristics of the fluids contained within it, 2) the geological configuration of the reservoir and its lithology, 3) the pressures and temperatures to which the fluids and rocks are subjected, and 4) the rates and total volumes of fluids that are withdrawn from it and injected into it.

Accurate prediction of reservoir behavior turns upon knowing as much as possible about the first three factors and being able to describe them numerically. Then the values ascribed to the parameters which describe the reservoir and its fluids are inserted into mathematical equations which represent the physical laws controlling fluid flow. The particular mode of operating the reservoir, fluid production and injection as a function of time through wells deployed at specific locations in the reservoir, is then stipulated and the production behavior of the reservoir results from the simultaneous solution of the mathematical equations.

The physical laws, which are represented mathematically in carrying out such a reservoir prediction, are inviolate. However, to facilitate solution of the many simultaneous equations that represent the laws governing flow of fluids from point to point in the reservoir, mathematical approximations are frequently employed even when using high speed digital computers. The accuracy of the predictions become primarily a function of how reliably the reservoir analyst knows the correct values of the parameters of the subsurface fluids, of the relationships between reservoir fluids and the reservoir rock, and how well the reservoir has been described mathematically. The reliability of such predictions increases as observations are made of reservoir performance and the values of the reservoir and fluid parameters are adjusted to account for observed behavior. The reservoir is only completely understood the day that it is shut down, and then only with respect to its response to the particular operating plan that was used.

Nevertheless, early predictions are important and necessary. It is only by predicting the behavior of various modes of operation that the operator can choose that scheme which promises to be the most rewarding -- an optimum combination of produced volumes and economic return. The prudent operator usually allows for sufficient flexibility in implementation of his chosen mode of operation should performance of the reservoir indicate that the values of the dominant parameters as gleaned from reservoir performance are different than those chosen at first based on diagnostic tests, laboratory analysis and analogy with his experience.

Crude oil reservoirs tend to be unique entities, and analogy has proven not to be too reliable except in broad generalizations. The American Petroleum Institute has studied the possibility of correlating reservoir performance of fields in the United States, Bulletin D-14, 1967. The correlations that were achieved are inadequate to predict the performance of any one reservoir with an acceptable degree of reliability although they can predict the average performance of a group of reservoirs.

The Sadlerochit reservoir in the Prudhoe Bay Field is the largest reservoir that has ever been discovered in the Western Hemisphere. The physical laws governing fluid in this reservoir are the same as those governing fluid flow in any other reservoir. The task of modelling the reservoir and the description of the reservoir is simply a bigger task. Because of the tremendous financial investment that will be made to produce this reservoir, the operators have made a great investment in time and expense to model the reservoir and

98-069 O - 78 - 23

predict its performance. The Department of Natural Resources, Division of Oil and Gas, has also modelled the reservoir and carried out reservoir predictions. This work was contracted to H. K. van Poolen and Associates, consultants to the Division of Oil and Gas. Still other predictions of reservoir performance were executed for other private and public purposes by other consultants.

This study was conducted, not to make additional predictions, but to audit the content and conclusions of these reservoir predictions which had already been published. The major conclusions of this study follow. Additional conclusions will be found in Chapter VII.

MAJOR CONCLUSIONS OF THIS STUDY

I. With Respect to the State's Responsibility to its Citizens to Analyze the Operating Plans for the Prudhoe Bay Field

The State of Alaska's Division of Oil and Gas has not adequately represented the State in ascertaining the reliability, sensitivity and economic impact of the operating plans for the Prudhoe Bay Field proposed by the operators of the field, nor has the Division adequately compared the work presented by the operators to the work carried out on their behalf by their consultant.

The inadequacy of the Division's review of the work of the operators and of their consultant is primarily due to the fact that the Division of Oil and Gas is not adequately staffed to oversee the State's interests in the largest crude oil reservoir discovered in the United States. The Division has not been assigned the responsibility for assessing the economic impact of the operating plans on the State, but neither has any other agency of the State. This is a vital function in the exploitation and management of the state's resources. It is therefore mandatory for the State to increase the competence and scope of the Division of Oil and Gas at the earliest possible date in order for the State to be assured of deriving maximum benefits from its resources for the citizens of the State of Alaska.

Immediately, the staff of the Division of Oil and Gas should be strengthened to guarantee that adequate surveillance of reservoir performance, and data collection and recording does occur for the necessary task of reviewing and analyzing reservoir performance to protect and strengthen the state's interests. The plans for such surveillance and data collection should be comprehensive but well planned so as not to interfere with or be an undue burden on the operators in their pursuit of efficient management of producing operations.

2. <u>With Respect to the Approval of Plans for Future Operation of the Prudhoe Bay Field</u>

No operating plan should be approved or committed to by the State at this time which does more than assure the minimum orderly development of the field to attain crude oil production at the rate required for successful operation of the Aleyska Pipeline.

This conclusion is based on the belief that it is necessary to confirm from field performance supplemented by special tests and testing procedures and continuing analysis that the most likely values of the parameters of the reservoir and reservoir fluids have been chosen as input for the mathematical predictions of reservoir performance. Further, that the mathematical description of the reservoir is adequate to account for observations made of field performance.

It follows that net withdrawals (sales) of gas should not be committed to at this time. A period of no less than two and possibly as much as five years will be required to make the necessary observations and tests to validate the values of the various reservoir parameters that affect reservoir performance. Only by the accumulation of such data can performance predictions be made which will confirm to the state the desirability and/or necessity of selling the gas from the Sadlerochit reservoir. During this period the State should embark on studies which will reveal the desirability and advantage to the state of other modes of utilization of the gas (other than pipe-line sales some five years hence as proposed by the operators) should it be concluded that it is not necessary for economic production of the crude oil for such early sales to occur.

The State need not have any fears of relinquishing any economic benefits from the early sales of gas, all other factors being unaffected or rendered more favorable by such a delay.

3. <u>With Respect to Potential Recovery of Additional Quantities of Crude Oil Over and Above that Which the Operators Believe is Recoverable by Conventional Technology</u>

Twelve ~~B~~illion or more barrels of crude oil will be left behind in the Sadlerochit reservoir at the conclusion of conventional operations sometime after the turn of the century. This is not due to the inadequacy of any of the specifically proposed operating plans, but due to the limitations of conventional technology in exploiting crude oil reservoirs. Because of the magnitude of this volume of unrecovered oil, and because of the unique nature of reservoirs, the State should not rely solely on the spin-off of technology being pursued for other reservoirs for the development of a tertiary recovery process that may be applicable to Prudhoe Bay.

The ~~S~~tate SH~~w~~ould, on its own if necessary, but preferably in conj~~ection~~UNCTION with the operators and the federal government embark on an intensive research and development program to ascertain the feasibility and applicability OF a tertiary recovery process for the

Sadlerochit reservoir. Since the primary recovery process BEING ~~that is~~ used may affect the applicability of a terti~~ary~~ARY process, the implementation of such a research and development program should be expedited immediately .

Chapter III.

POROSITY, OIL SATURATION AND THE OIL IN PLACE

An oil reservoir is not a uniform accumulation of sand grains. The interstitial voidage, the porosity, varies throughout the reservoir. In order to estimate the pore space that is filled with oil, gas and water, cores are taken from a number of wells in the field and analyzed in the laboratory. Since it is impossible to sample every inch of every well, electric logs are used to make such estimations on a routine basis.

In a sandstone such as that of the Prudhoe Bay reservoir, it would be expected that the density log would give the most reliable result for estimation of porosity. Unfortunately, at the top of the formation there is a significant concentration of iron sulphide (pyrite), a very dense material which prevents a reliable calibration being made between the log response and the true porosity. Iron sulphide occurs to a lesser, but erratic degree throughout much of the rest of the formation. The density log (a type of radioactive log employing the Compton scattering of gamma rays by electrons) does not give reliable porosity values in such a situation.

In lieu of the density log, the acoustic log was used as the standard tool for measuring porosity. The log was calibrated in the laboratory against cores whose porosity was subsequently determined. This cross checking of the acoustic log response against actual cores was done to obviate the problems that are usually encountered in using standard relationships between porosity and acoustic velocity. There are three factors that tend to make the standard response relationships result in estimates of porosity that are too high: 1) presence of interbedded shale; 2) lack of complete consolidation and compaction of sandstone matrix; and 3) presence of residual oil saturation in the flushed zone measured by the sonic log.

The laboratory calibration should tend to reduce these errors. However, the core porosities determined in the laboratory are themselves probably higher than the true values in the formation. The principal reason for this is the change in effective stress between the in-situ conditions and those on the surface. In a well consolidated sandstone such as that of the Sadlerochit, the difference in porosity may be small, but not trivial, when estimating the amount of oil originally in place in a reservoir.

A censored report made available to us by the Division of Oil and Gas indicated that the analysis of the cores from one well showed a one porosity percent reduction when the cores were stressed to reservoir conditions. However, the validity of this correction and its applicability to all measurements could not be verified by us since the actual data had been removed from the report. From our discussions with the operators we would conclude that they did not make such corrections in their resource studies although some of those working on the mathematical reservoir simulation studies suggested that such corrections had been made. We were not able to verify just what had been done but the greatest evidence suggested no attempt had been made to take into account porosity changes as a function of confining pressure.

The important conclusion is that since both the acoustic log porosity and the core porosity both tend to be too high, a cross plot between these two quantities does not demonstrate that the calculated porosity is the correct in-situ value. It is possible of course that neither of these measurements deviated significantly from the correct, in-situ values but no evidence to support such a contention has been provided.

Obviously, if the porosity measurements result in porosity values that are too high, the estimate of void space and of oil in place will be too high. Actually, the error in the estimate of oil in place will be somewhat larger (on a percentage basis) than the percentage error in the porosity. This is so because porosity itself enters into the calculation of the oil saturation.

Use of porosity values that are too high in the Archie equation to evaluate water saturation from resistivity logs will result in water saturations which are too low; the oil saturations will be correspondingly too high. The net effect is to further increase the upside error in the estimate of oil in place.

It is our belief that the estimate of the oil in places as a result of neglect of the effect of pressure on porosity could be too high by a factor of 5% to 10%.

The consultant to the Division of Oil and Gas has presented an estimate of original oil in place which is some 10% less than that calculated by the operators. Although this difference can be traced to his use of a porosity value consistently lower than that used by the operators, it is not certain whether the deviation in porosities resulted from differences in interpretative technique or from the fact that a much smaller data base was available to the concultant. The consultant did not correct for the effect of pressure on porosity as far as we could determine. It must not be assumed that the two estimates of oil in place represent the probable range within which the true estimate of original oil in place falls. There may be a consistent difference in interpretation or in the data base which only a detailed study could reveal.

Although the estimates of the oil in place do not affect the relative estimates of recovery efficiency nor of the conclusions concerning the preferred operating scheme, there is some concern about the differences between the two estimates. It is somewhat surprising that this point was not raised for significant discussion at the hearing in Anchorage this past May. A 10% difference in original oil in place is some two billion barrels. Such a difference between the estimates of two reservoir engineering groups is worthy of serious attention.

Chapter IV.

RESERVOIR PERMEABILITY, CONFIGURATION, AND RECOVERY MECHANISMS

The permeability of the formation, just as the porosity, varies throughout the reservoir. Actually, in a single sedimentary unit it might be expected that the variation in permeability can be studied statistically and an average permeability assigned to the unit. This is basically true, but it does not take into account local extremes which may occur randomly within the unit and cause marked differences in behavior. For example, shale deposition within a sandstone member may have occurred because of a marked reduction in fluid velocity in the stream from which deposition took place, or a very coarse, heterogeneous deposition (conglomeratic section) may have occurred in a high velocity stream. The occurrence of such variations in rock structure across the producing section may cause a marked change in the flow of fluids in the reservoir. Perturbations in the rock composition and structure can greatly vary the advance of one fluid into another thereby exacerbating or ameliorating phenomena such as viscous fingering, channeling, and coning. These effects become most pronounced of course, when the production mechanism relies on the encroachment of water or gas into the oil column.

A reservoir can be sampled only by drilling a hole through it. The nature of the reservoir between the holes can only be conjectured. The Sadlerochit reservoir, unfortunately, is not, as noted several times earlier, a uniform reservoir. The Sadlerochit comprises several sedimentary units, varying from high energy, conglomeratic sands to low energy shaly sands. In the former the permeability is likely to be high throughout whereas in the latter the possibility is great that marked changes in permeability will occur over relatively short distances. As a result of such changes the ability of fluids to flow within or through shaly sands is greatly reduced. As will be discussed below, this uncertain variability in rock characteristics makes constructing a realistic model of the Sadlerochit a difficult job.

A further complication is that the reservoir is intersected by several faults across which fluids may or may not flow. Not until significant volumes of fluids have been produced from the reservoir and the associated pressure changes carefully analyzed will it be possible to reduce the uncertainty in the reservoir configuration and in the effect which non-homogeneities in the reservoir configuration will have on future reservoir behavior.

It is, nevertheless, necessary to construct a model in advance in order to make an initial choice from the possible production schemes that could be used to produce the reservoir. To construct a model, at each point in the reservoir a PERMEABILITY value must be assigned ~~to the permeability to~~ FOR each of the several fluids contained within the pore space. Unfortunately, permeability cannot be measured in-situ. Production tests provide transient pressure data which can be interpreted to determine "kH" values, the product of the permeability and the thickness of the productive formation. The value of kH thus obtained is an average value representation of the rock in the immediate neighborhood of the well when filled with the particular fluid saturations which exist around the well bore at the time the test was made. It was noted in Chapter III that the permeability of the rock to oil and water and gas varies as the saturation of these fluids vary. Since the saturations will change during production, to predict reservoir behavior it is necessary to have more than one value of permeability at one particular saturation.

Cores brought into the laboratory can be mounted in an appropriate apparatus, and the relative permeability to oil and water, or to oil and gas, can be measured over a fairly wide range of saturation. The data is obtained by simultaneously flowing the two fluids through the core until an equilibrium condition is reached. However, the values of relative permeability obtained are not unique functions of saturation; different values will be attained depending upon the direction in which the saturation of oil (or water) is changing. The drainage relative permeability values are those which control fluid flow when oil saturation is increasing, and the imbibition values are those which are obtained when the water saturation is increasing.

Even though there are standardized laboratory methods for measuring relative permeability, there is some question concerning the significance of laboratory derived relative permeability data. The operators did use preserved cores and reservoir fluids to determine the relative permeability functions recognizing the fact that cleaning of cores and the use of laboratory fluids frequently give different results. Relative permeability data obtained on cleaned cores usually result in significantly higher relative permeabilities to both oil and water. On the other hand, the reliability of data obtained on composite cores (a series of small cores butted against each other), which were used by the operators to develop the oil-water relative permeability data, has not been established in the technical literature. The multiple end effects encountered at each joint may have an effect on the derived values for the relative permeability.

The most serious problem in regard to relative permeability arises in estimating the end point values of relative permeability, viz., the saturations at which the permeability to either fluid (most importantly, of course, to oil) becomes zero (if it does so at all when saturation is greater than zero). As noted in Chapter III, for oil the end point saturation and the shape of the relative permeability determine in great measure the actual efficiency with which the oil is displaced by water or gas. A very low end point (residual) saturation to oil is of little consequence if an excessively larger number of pore volumes of water must be forced through the rock to reduce the oil saturation to that value. The problems arising in the definition of the relative permeability curve at low oil saturations ~~is~~ ARE highlighted by the differences in the conclusions of the operators and of the consultant to the Division of Oil and Gas, H. K. Van Poolen and Associates.

The averaged relative permeability curves of the operators do not appear to differ greatly from those used in the study prepared by H. K. Van Poolen for the Division of Oil and Gas.

The Division of Oil and Gas would not permit us to view the original data they had on hand; the only curves available to us were those published in the Van Poolen report and those presented by the operators at the Anchorage hearings in May. We are therefore unable to rate the quality with which the curves actually fit the experimental data nor the quality of the experimental data points themselves.

Van Poolen's curves give somewhat higher values for the relative permeability to oil for both the oil/water and oil/gas systems, and a significantly lower relative permeability to gas in the oil/gas system. The most significant difference between ~~the two~~ VAN POOLEN AND THE OPERATORS results from the interpretation of the basic data from which the curves were derived.

Van Poolen interprets the relative permeability data to indicate that sizeable end point saturations exist. Average irreducible oil saturations of 0.42 ± 0.10 and of 0.23 ± 0.10 were reported by Van Poolen for the oil/gas and oil/water systems, respectively. (However, in the simulation studies, Van Poolen used an irreducible oil saturation of 32% to gas.) The operators do not believe that irreducible oil saturation to gas is this large. They have attempted to verify their belief by measuring residual saturations resulting from subjecting the fluids to a large centrifugal force developed by placing the cores in a rotating device. By plotting and extrapolating their results on semi-logarithmic graph paper (relative permeability on a logarithmic scale vs. saturation on a linear scale) they obtain a continuous curve which can be extrapolated down to very, very low oil saturations. The corresponding relative permeability values are several orders of magnitude below a value of 0.01 (an approximate lower limit to laboratory measured values of relative permeability).

We are not certain of the validity of the centrifugal results, particularly in regard to the scaling of possible time-dependent effects. Over geological time periods we can expect the non-wetting oil phase to have been practically completely drained from a gas cap. We have no evidence that such drainage is approached under dynamic operating conditions and a producing life of twenty-five years.

Although much careful laboratory work and theoretical analysis was probably carried out to justify the use of the low residual saturations secured in the laboratory centrifuge, ultimate validation can only be secured from observations in the actual reservoir. When the operators' curves were used in the simulation studies, the residual oil to gas invasion in the areas where gravity stabilizes the displacement falls to values well below 20%, and average significantly less than the end point residual saturation reported by Van Poolen. 2

This result from the operators' simulation studies is the most crucial one in their representation of the preferred operating plan, since it provides the basis upon which expansion of the gas cap is chosen as the preferred operating scheme for the Prudhoe Bay Field. It is again surprising that the Division of Oil and Gas did not raise this matter at the Anchorage hearings in May. The contention of the operators that such low residual saturations to gas invasion would be achieved was in opposition to the interpretations that were reported in the studies which they sponsored.

To find support for the operators' contention that such low residuals of oil will be attained by gravity drainage at the rates called for in the planned operation of Prudhoe Bay, we searched the literature for supporting case histories. Unfortunately, there is not much published data on this score. Certainly, the results reported by Exxon for the Hawkins Woodbine Reservoir in 1975 tends to support the concept that residual oil saturation can be driven down to extraordinarily low values by gas cap expansion-gravity drainage. The Hawkins Woodbine producing formation contains a much more viscous crude than does the Sadlerochit, and on this basis it would be expected that the efficiency with which oil is displaced by either water or gas would be low because of viscous fingering. On the other hand, the permeability of the reservoir sands is very high, 1194 mds. for the Lewisvillive member and 3396 mds. for the Dexter (six to seventeen times ~~fold~~ greater than that of the Sadlerochit). The residual saturations to both gas and water invasion are quite low in the cores taken from the reservoir, 3% and 15%, respectively. These residual saturations are extremely low for such a crude and raises the possibility that these cores were flushed during the coring operation itself as suggested by the operator. It should be added that the higher saturation of gas in the gas invaded zones could have promoted flushing and given rise to the apparent low residual saturation. Woodbine reservoir sands are known to be driven to very low residual oil saturations by water encroachment , viz., in the East Texas field cores have been revealed to have saturations less than 10%.

However, the volumetric results are impressively different. A low rate of production may have contributed significantly to these results; for many, many years withdrawal rate from the reservoir was limited by the Texas Railroad Commission's imposition of allowable production rates. For results from the operation of the Hawkins Woodbine reservoir to be extrapolated to Prudhoe Bay or any other reservoir, consideration must be given to rates of withdrawal; and, in particular the rate at which the gas cap did in fact move southward in the Hawkins reservoir. It is worth~~y of~~ noting that the operator of the Hawkins Field in opting for enhancing recovery from the field by gas injection into the gas cap will repressure the gas cap and maintain the pressure during the subsequent production life rather than depend exclusively on gas expansion to lower pressures.

In a Venezuelan reservoir familiar to us efficient gravity drainage is being achieved by complete reinjection of produced gas and maintenance of reservoir pressure.

The writers have had the opportunity to review the performance of a relatively small group of some twenty reservoirs in Texas which have been subject to recovery by gas reinjection into the gas cap. The reported average recovery efficiency from such reservoirs is of the order of 44%. This efficiency is somewhat greater than that from a much larger sample of sandstone reservoirs subjected to an induced water flood, viz., 38%. An analysis of reservoir properties of the two groups indicates that the former (gas cap reinjection) have significantly better parameters (particularly, permeability) than those in the latter group. When the performance of the reservoirs being produced by gas reinjection is compared to that of a group of reservoirs having approximately the same parameters, but subject to a natural water drive, they do poorly in comparison, 44% vs. 54% recovery. Unfortunately, a substantive comparison of performance, given equivalent reservoir parameters and drive mechanism could not be found. In summary, we could not find an unequivocal verification for the supposition that in the Sadlerochit the residual oil saturated to gas expansion will be significantly less than that to water invasion, viz., that less oil will be left behind by gravity drainage than by water encroachment.

The occurrence of a strong natural water drive in the Sadlerochit has been virtually ruled out because of the deterioration of reservoir properties in the water column downdip from the oil accumulation. Encroachment of water may be further limited by the existence of an

98-069 O - 78 - 24

altered, more viscous crude at the oil water contact. It is not certain whether the tar mat *per se* would be a significant barrier to fluid flow.

Had there been a strong water drive in the Sadlerochit, then the chances would have been great that the operators would have chosen to produce the reservoir by taking advantage of the water drive. The oil water contact would have been allowed to rise and produced solution gas would have been reinjected into the cap to maintain its pressure.

One is then led to inquire why, in the absence of a natural water drive, a water flood is not initiated to execute the same function that a natural water drive would have played. The primary reason for not choosing to do so is the contention of the operators that allowing the gas cap to expand to lower pressures will result in the high displacement efficiency (low residual oil saturation) already alluded to. Additionally, there are questions concerning the continuity of the shales in the lower sedimentary units and the tar mat over various areas at the oil water contact. These latter problems could probably be overcome by the judicious choice of injection locations. Then, too, there is the cost of implementing a large scale water flood at this time. With such heavy investments already made over a significant period of time without the production of revenues, and in the perceived absence of clear cut advantages, a choice would be made by any prudent operator to chose an operating plan that did not require additional investments.

Gas Expansion-gravity drainage, the preferred production method of the operators, leads to a reduction in reservoir pressure.

A significant lowering of the reservoir pressure before final blow down acts to reduce oil recovery, in the absence of compensating factors, in a dual manner. First, the loss of pressure reduces the rate of influx of crude into the producing wells thereby accelerating the time at which production falls below the minimum economic limit. Secondly, the pressure loss allows dissolved gas to come out of solution in the crude oil thereby increasing the oil content of the oil phase (a solution of gas in oil) that is left behind the displacement front. The total amount of unrecovered oil is increased. In addition, the loss of solution gas results in an increase in crude oil viscosity which again reduces the influx of oil into producing wells.

The operators eventually intend to offset some of the effect of that component of the pressure reduction due to gas withdrawal from the cap by injecting water into the gas cap. This is preferred BY THEM to a greater degree of reinjection of the produced gas because of the presumed saleability of the gas and because of the energy consumed in gas injection. However, no data has been presented by the operators to compare the cost of eventual water injection with the cost of reinjection of gas.

The operators have presented results of their studies which indicate that the recovery efficiency of the preferred operating plan could be increased from approximately 36% to approximately 40% by the initiation of source water flooding five to ten years after production starts from the Prudhoe Bay Field. It appears from the limited information made available to us that a major fraction of the water to be injected would be injected into the gas cap where it would serve primarily to retard the rate of pressure reduction. Some water would be injected into the oil column to increase the sweep of displacing fluid in the reservoir. However, we would estimate that the reservoir would be far from having been completely swept by water and expanding gas at the time of abandonment.

Prudent analysis of alternative producing schemes would in our experience have required a thorough technical and economic comparison of early implementation of a water flood to an extent sufficient to approach complete pressure maintenance and of total reinjection of produced gas without any injection of water other than that produced from the reservoir. These would have served as references for the evaluation of all other plans. Although these may have been studied by the operators for their own use the results of such analyses were not presented to the State. The Division of Oil and Gas did not request such studies from ~~their~~ ITS consultant.

The operators are planning to conduct a small scale water injection operation sometime in the next two or three years to get information on the actual residual oil saturation to water encRoachment. This, together with observations on the residual oil saturation behind the advancing gas contact, will serve to erase any doubts on the comparative efficiency of the two displacement mechanism. Should the results of such observations lead to conclusions concerning the values of important parameters that are different from those ~~input~~ USED in~~to~~ the current simulations then consideration can be given to a revision in operating plans. Should the reservoir performance be considerably different from that which is anticipated, then the opportunity for revision will exist only if the necessary options are still available. Thus, it does not appear prudent at this time to commit to the withdrawal of gas from the reservoir for pipe line sales until it is certain that such sales will not interfere with the adoption of possibly superior production schemes. It would also appear to be more than prudent for the operators to accelerate their field verification of the residual oil saturation to water flooding.

A major contributing parameter to the choice of the gas expansion-gravity drainage process as the preferred process is the conclusion that the vertical permeability in much of the Sadlerochit reservoir is a high fraction of the horizontal permeability. Because of the nature of the deposition process, it is a general observation that vertical permeability is less than horizontal permeability. The sand grains tend to align themselves parallel to the direction of flow of the water from which they were deposited. Thus, the more elongated the sand grains, the lower will be the ratio of vertical to the horizontal permeability. Measurements on individual, small cores indicate that the vertical to horizontal permeability ratio is not significantly less than 0.5. However, the existence of interbedded shale streaks and shale beds can seriously reduce this ratio over greater thicknesses. Obviously, an impermeable layer of shale will reduce the vertical permeability to zero across any vertical macrosection of reservoir that contains such an impermeable layer.

Although shales have been observed in cores and on log traces throughout the Sadlerochit, correlation of the shales from one well to another is common only in the lower sedimentary units which are shalier than the upper zones. The operators have made statistical analyses of the occurrence and a real extent of shales based on the observations in the wells, and have used these observations to introduce shales into their reservoir model. Based on these analyses the operators divided the reservoir into two sections, a shaly one and a non-shaly one; and conducted simulation studies on each to estimate the differences in behavior that may be anticipated.

Again, this is very critical input into the mathematical model since IF ~~should~~ the frequency and impermeability of the shales have been underestimated, THEN the areal sweep of the oil column by the expanding gas cap will be less than now anticipated by the operators.

A high ratio of vertical to horizontal permeability has been indicated to promote efficient oil recovery by gravity drainage. It also promotes gas coning which works against efficient recovery of the reservoir crude oil.

Gas coning is a very complex phenomenon which involves excessive production of gas from the gas cap along with the crude oil. Significant reservoir energy is thereby lost as the gas is produced. Gas coning occurs because of the differences in density and viscosity between the overlying gas and the oil. Under the influence of the pressure drawdown required to cause the influx of fluids into a well bore, the gas oil interface will tilt downwards around the well and may reach the level of the perforations. This phenomenon is highly rate sensitive. As the velocity of the fluids converging on the well bore increases, the pressure drawdown around the well bore also increases. Since the tilting of the gas oil contact increases as a function of the pressure drawdown, the tendency to suck the gas cone into the perforations increases with production rate into any single well.

The operators are completely aware of the potential damaging effects of gas coning on production performance and have already requested permission to reduce the spacing in the field to 160 acres in order to minimize such coning. An increase in the number of wells, while keeping the total production rate constant, will, of course, lower the production rate per well. The lower production rates, in turn, lower the pressure drawdown around each well and therefore REDUCE the EXTENT ~~tendency~~ of gas coning ~~to occur~~.

Water coning, the upwards tilting of the oil water interface and excessive water production accompanying oil production, will not be as severe as gas coning. However, the operators will choose the intervals to be perforated in the producing wells so as to minimize both gas and water coning.

Because of the importance of the vertical permeability within the reservoir, it is somewhat surprising that neither the state nor the operators sought to use a published technique which has the potential for measuring the in-situ vertical permeability, at least within the vicinity of a well bore.

It is certain that if the Sadlerochit reservoir is produced according to the plans set forth by the operators (or by any other conventional technology) the oil left behind in the reservoir when it is abandoned will exceed twelve billion barrels.

Neither the operators nor the state have as yet pursued any detailed studies, to our knowledge, of the potential of tertiary or enhanced recovery techniques in recovering some of this residual crude oil. We do not wish to imply in any way that such techniques are currently available, although many have been proposed and are under study for reservoirs in the lower 48. Because of the enormity of the residual and the critical supply situation for crude oil in the United States, which will only worsen in future years, it is of utmost urgency to consider as soon as possible the development and applicability of enhanced recovery techniques for the Prudhoe Bay Field. It is none too early to do so because the operating scheme to be used during primary operations may have a significant effect on the successful implementation of tertiary recovery processes. A successful tertiary recovery process might well recover an additional four billion barrels of crude oil. This will be again discussed in Chapter V?. ?

Chapter V.

PERCENT RECOVERY ESTIMATES AND COMPUTER SIMULATION MODELS

In the absence of any data to indicate trends in Prudhoe Bay's production performance, theoretical reservoir prediction methods provide the only means of making recovery estimates. To apply these prediction methods to Prudhoe Bay computer models of the reservoir were constructed. These models use well established equations to predict over time (a) the simultaneous flow of oil, gas and water throughout the reservoir system and (b) the fluid pressure at each point in the reservoir resulting from different rates of production from and fluid injection into the reservoir. The computer programs used to obtain these predictions have been used many times in other equally ~~complex~~ RESERVOIRS development of these. Because of the relatively recent (a little more than a decade ago) ~~of the~~ sophisticated computer based schemes for reservoir prediction, it is not possible to find a large number of reservoirs whose history was predicted from scratch, and which have been operated long enough to evaluate the match of prediction with performance. On the other hand, there is a significantly larger body of documented successful predictions of reservoir performance that were made for reservoirs for which some historical production performance was already available. In these cases the model could be fixed by history matching procedures.

There is an old adage in the computer game, viz., garbage in equals garbage out. Interpreted here this means that if the models constructed do not reasonably approximate the configuration of the reservoir and the distribution of fluids within it, the results will be worse than meaningless; they will be misleading. Likewise, if the values of the parameters which are used in the model to represent fluid flow through the porous media under the continuing changes in pressure and saturation resulting from production are not a compatible blend of the important physical-chemical properties of the fluids and the rock with the model's aggregated representation of the reservoir, the results will be meaningless.

Accomplishing the first requirement necessitates a careful analysis of the structure and composition of the producing formation, and of the distribution of fluids within the pore space. Both the consultant to the Division of Oil and Gas and the operators carefully interpreted data from well logs and cores to define the structure of the producing formation. The operators gave much more consideration to the composition of the formation, however, than did the consultant. The important composition parameter is the amount of shale interbedded within the sandstone producing member. The major impact which this constituent has on fluid flow was discussed earlier.

The operators concluded that several correlatable interbedded shale layers act as total barriers to vertical flow over considerable portions of the Sadlerochit. They also conducted extensive statistical and computer modeling studies of vertical cross sections of the Sadlerochit to estimate the reduction in vertical permeability caused by shale stringers visible in individual wells but not readily correlatable between wells. The reduced values of vertical permeability were then FED INTO ~~input to~~ the large computer models used to predict reservoir performance and percent recovery. In ITS ~~his~~ prediction model the consultant simply fixed vertical permeability equal to 0.1 times horizontal permeability; in the layers of the model representing cleaner sand sections this factor was increased to 0.3 or 0.5.

As a result of these differences in accounting for the effects of interbedded shales, the flow patterns in the consultant's model must have been drastically different from those in the operators' models. It is surprising that the significance of this difference was not examined DURING ~~in~~ the Anchorage hearings.

To determine the fluid distribution within the formation both the operators and the consultant appear to have thoroughly analyzed all available basic data. These include well logs, flow tests and fluid samples. With the exception of the anomalous behavior observed in the Eileen area where clean oil is produced from a section of the Sadlerochit for which the calculated water saturation is surprisingly high, the fluid distribution obtained seems eminently correct. Of course, the extent to which the several faults in the Sadlerochit will affect flow will not be known with certainty until sufficient production data are available. In the present studies the effect of faults has been assumed minimal, a reasonable assumption based upon the fact that the elevations of gas/oil and water/oil contacts are fairly uniform throughout.

Accomplishing the second requirement that the values of the parameters used in the modeling studies comprise a satisfactory translation of the basic reservoir data into numbers within the model which will cause it to make realistic predictions is a subtle art. The efforts discussed above to determine the most likely value to assign to vertical permeability throughout the recovery prediction model illustrate both the advantage of having considerable practical reservoir modeling experience to decide the proper way to proceed and the painstaking work required to obtain a suitable translation.

Other important situations which had to be dealt with were the assignment of values to the parameters, of the aquifer, which determine the amount of water influx and pressure support to be derived from the aquifer; and the way in which to model the effect upon water influx of the heavy oil zone of variable thickness which lies just above much of the water/oil contact. The base data for the first situation are the porosities and the permeabilities of cores taken from wells penetrating the Sadlerochit formation outside the limits of the oil-bearing region. Sufficient data points were available to establish with reasonable certainty that the reservoir properties deteriorate downdip; and the parameters introduced into the model reflect the poor qualities of the aquifer.

Deciding what to do in the model to reflect the heavy oil zone is a more subjective problem. Heavy oil or tar barriers have been observed at the water/oil contact in many reservoirs throughout the world. A tar barrier of varying flow resistance underlies the Hawkins Field mentioned earlier ~~above~~; similar tar barriers exist at the water/oil contact in both the Abqaiq and Ghawar Fields in Saudi Arabia. Interpretation of production data from these fields indicates that these tars act as an impediment to flow of water from the aquifer, but constitute complete flow seals only in limited areas, if at all. In Prudhoe Bay the generally held opinion seems to be that the heavy oil is more mobile than in these examples just cited so that the reduction in the model's permeability at the water/oil contact to reflect the flow barrier should be less. The correct value to assign is, however, uncertain and will remain so until sufficient production data are available to allow a quantitative analysis to be made.

The effect of this uncertainty on reservoir predictions is reduced by the fact that the aquifer has such low transmissibility.

Two other important translation problems which had to be dealt with in constructing the recovery prediction models were how to represent the effects of water and gas coning and what relative permeability curves to use. As discussed previously the high pressure gradient around a producing well can suck a cone of gas down (or water up) into the perforations. In terms of reservoir dimensions the radius of the top of this cone is small, say 50 feet or so. In the reservoir prediction models the dimensions of the grid blocks used to represent the reservoir are much greater than the dimensions of such a cone. Typically, the grid blocks had a length of 1000-5000 ft. and a thickness of 40-100 ft. In the model the pressure and saturations calculated are volume averages over the grid block, and the composition of fluids flowing out of a grid corresponds to these volume average saturations.

In order to realistically incorporate the effects of coning into their prediction models the operators first constructed single well coning models. These are cylindrical with a single producing well at the center; the length of the cylinder spans the producing formation, and the maximum radial dimension is, say, 2-10 times the radius of the fully developed cone. The coning models are used to determine the amount of coning as a function of the distance from the fluid contact to the nearest perforations, pressure drawdown between the perforations and the surrounding average reservoir pressure, and ratio of horizontal to vertical permeability, including, of course, any local shale barriers. (Coning is also influenced by the densities and viscosities of the fluids, but these are fixed by pressure and temperature.) The production performance of the detailed well coning models was transformed into a set of curves which were then used in the reservoir prediction model to more accurately predict the producing ratio of each well in the recovery predictions.

H. K. Van Poolen in his study prepared for the Division of Oil and Gas did not use this rather painstaking approach to determine producing ratio. It would be expected, then, that his results should tend to be more optimistic than those of the operators, i.e., his

GAS OIL RATIOS WATER OIL RATIOS

(GOR~~'s~~) and (WOR~~'s~~) should tend to be lower. The significance of these differences was not considered at the hearings in Anchorage.

Three important aspects of the relative permeability curves had to be considered in the prediction models; how to account for gravity segregation within a single grid block, whether to use the drainage or the imbibition curve, and what values of end point or residual saturations to use. The operators assumed that the fluids were segregated within each grid block containing a fluid/fluid contact. For example, in some instances if the gas/oil contact fell in a cell it was assumed that the portion above the contact was filled with gas plus residual oil and that below the contact the cell was filled with oil saturated with gas at the average pressure in the cell. The relative permeability curves used in the model were adjusted to reflect the fact that flow from this cell into its neighbor would consist of gas above the contact and oil below the contact.

The operators assumed that the drainage relative permeability curve applies on first opening the reservoir to production. This curve is assumed to continue to apply until water influx into a cell begins at which time a rapid transition is made to the imbibition relative permeability curve. No such assumption was made by Van Poolen.

As discussed previously the most critical considerations in the recovery models ARE ~~is~~ the values to assign to the end point or residual saturations. Aside from the uncertainty discussed earlier about what values will be representative of behavior in a small sample of the reservoir rock, another uncertainty arises from the modeling process itself. The values measured in the laboratory are representative of conditions within a microscopic pore volume, which for purposes of discussion can be thought of as that contained within 1 to 2 to 3 cubic inches of rock, which has been thoroughly swept with gas or with water. In the prediction models the volumes of the grid blocks varied from about 1 million cubic inches to 50 trillion cubic inches. The models compute average oil saturation vs. time. Given the laboratory values, considering the discrepancy in volumes just cited, what values of residual oil should be used in the reservoir models to cause them to predict most accurately the percent recovery which will be observed in the reservoir. None of the reservoir blocks will be as thoroughly swept as was the microscopic pore volume in the laboratory, but the difference will not be uniform and is not predictable with certainty. The operators assumption of intracell gravity segregation deals partially with this problem.

As the above discussion indicates there are many uncertainties surrounding the recovery predictions. These uncertainties can only be eliminated or reduced by collecting production data and comparing observations to predictions. This process of modifying a model to improve the agreement between prediction and observation is standard procedure in the use of reservoir models; this process, alluded to earlier, is commonly called history matching. The operators indicate that they plan to continue working with their models and that as production data become available they will examine it looking for ways to improve the reliability of their models.

Likewise, the Division of Oil and Gas indicated that as soon as sufficient production data become available to warrant the action, they plan to request their consultant to update their model.

Whereas one can be sanguine about the thought that BY OBSERVING ~~with~~ performance the reservoir models can be increasingly fine-tuned AND THUS MADE BETTER ~~to be~~ able to predict subsequent performance; it is still necessary to choose what is believed to be the superior production process based on predictions which are made before any performance is available. In order for such a selection to be made, it is necessary to rate the comparative reliability of the input parameters that will control performance by different production methods and to rate the overall mathematical simulation procedure which is used.

With no doubt or reservations, we believe that the simulation scheme used by the operators is superior to those used by any others who have attempted to predict the performance of Prudhoe Bay. On the other hand, we do not believe the operators have in their public presentations reported on the effect on production performance of a sufficiently wide range of operating conditions. H. K. Van Poolen has studied the effect of a wider range of conditions, but still the variability was somewhat limited and somewhat arbitrary so that inter-comparisons between the results from changing conditions is not easily achieved.

The consensus conclusion of the operators as reported at the Anchorage hearings is that about 40% of the original oil in place may ultimately be recovered if their proposed operating plan is followed. This plan includes

1. Oil production to be initiated at the rate of 1.5 MMB/D.
2. 160 acre spacing to be used (with some 80 acre spacing).
3. Low pressure gathering systems and artificial lift.
4. Injection of all produced water. AND SOME APPARENTLY, AT A LATER DATE, SOURCE WATER.

In our contacts with the operators, we found that one of the operators appeared to take the lead in discussions with us and the supply of information. Although the other operators indicated their results were somewhat different than those of the principal spokesman they agreed that the differences were minor. Therefore, in the subsequent discussion we will refer to the results presented by one of the operators as being representative of the group.

The spacing of 160 acres and less (rather than the 320 acres originally believed to be suitable for Prudhoe Bay) and the low pressure gathering system and artificial lift were demonstrated to be necessary to raise the crude oil recovery efficiency from the high twenties to 34% while committing to the sale of natural gas of 2 BCF/D starting five years after crude oil production was initiated. By injecting the water produced along with the crude oil, recovery is raised to 36%.

The operators did not present a base case to demonstrate what recovery efficiency might be expected in the absence of any gas sales. A case in which gas sales were delayed for fifteen years, by which time over 80% of the ultimate crude oil has already been recovered, ~~recovered~~ WITH THE ULTIMATE AMOUNTING TO 37.5% of the reservoir crude oil. The comparison is not sufficient since when considering the total economics and cost/benefits of the project a run with no gas sales and higher spacings would be in order.

98-069 O - 78 - 25

Van Poolen, on the other hand, shows a significant effect of gas sales on recovery efficiency when sales are increased from 2 to 3 and then 4 billion cubic feet a day. The recovery efficiency is gradually reduced from 41% to 32% (a loss 1.9 billion barrels). Again, Van Poolen does not give a case without gas sales that can be directly compared with the three runs just cited. Extrapolation of the results of these three cases to zero gas sales would suggest that the recovery efficiency would increase to 9.1 billion barrels, or 47.7% of the oil in place.* Such explicit extrapolation is not justified, but the implicit trend certainly is in the absence of any other information. We therefore believe the State Division of Oil and Gas should have delved into these matters at the Anchorage hearings in May 1977. Again, it must be emphasized that there are some significant differences in the simulation techniques used by van Poolen and the operators, and there are significant differences in the input data (see below). However, we believe the trends established in any one model~~l~~ing procedure are significant even though absolute values of predicted performance may be open to question.

---

*Core Laboratories, Inc. in their report prepared for the Alcan Pipeline Company present results of mathematical simulations which show a monotic decrease in oil recovery from 8.36 billion barrels of crude oil to 6.23 billion barrels as the gas sales are increased from 0 to 4~~x~~ billion cubic feet a day. At the time Core Laboratories conducted their studies it was believed that gross production had to be only 117% of gas sales. Subsequent information indicates that the gross will have to be closer to 135% of net. Thus, the effect of a given value of net gas withdrawals (sales) would have even been more pronounced in the Core Laboratories study.

It is worthy of note that H. J. Gruy and Associates also found a significant difference in recovery with and without gas sales, the effect of no gas sales being such as to raise the recovery efficiency from 29% to 39% even without waterflooding. Gruy and Associates used the basic input of the van Poolen model, but a simulation scheme of their own.

The operators did not present the results of a full scale pressure maintenance program by water flooding without any associated gas sales. van Poolen did IN PART showing a recovery of 7.8 and 8.2 billion barrels, or 40.8% and 43.0% of the oil in place at maximum crude oil rates of 1.6 and 1.2 million barrels a day, respectively. These were the highest efficiencies reported by van Poolen, and would have probably been higher if the reservoir pressure was eventually drawn down to that of the reference case with gas sales. van Poolen implied in a subsequent report study that the production scheme used in reaching such high recovery efficiencies might have been unrealistic. We see no evidence for this although there has been no economic feasibility study made of the implied scheme of production.

Van Poolen does show that the effect of gas sales on reducing recovery can be compensated for by carrying out a water flood and changing the operational limits on gas oil ratios. Thus, the recovery is increased from 7.1 billion barrels (Run 8) to 7.9 billion barrels (Run 21). However, the latter result (gas sales, water injection and changed operational limits) is even slightly greater than the case for no gas sales and water injection, 7.8 billion barrels (Run 11). We believe that the result for no gas sales would be significantly higher if the run were continued, blowing down the reservoir to reach the same terminal pressure as in Run 21. It would seem to be in order for the Division of Oil and Gas to have sought to have performance predictions prepared for them that were compatible for direct comparison.

The operators did study the effect of limited water flooding, starting five to nine years after the initiation of production of crude oil (with gas sales starting five years after crude oil production) as already noted. Their studies indicate an increase in recovery can be achieved by such injection; a gradual increase from 36% to 40% as a function of the rate of water injection and its timing. A good amount of this increase appears to be due to the increase in the gas cap pressure, since a large fraction of the water is injected directly into the gas cap. The increase in recovery is not primarily due to a major sweep of the crude oil column by the injected water.

We believe that the operators have stressed gas expansion and gravity drainage as the principal modes of production because of their belief that the residual oil saturations to such a drive will be less than that to water. Gas sales are looked on with favor because of the reputed cost for continuing gas injection, and because of the relatively low present value of water flood recovered oil
does not
which doesn't speak well for additional capital investments ~~in~~ DURING the early life of the operation.

We believe that the State must look on the matter of crude oil recovery from a somewhat different stand point than that of the operators. The State, whether or not it is interested in reinvesting its earnings from the operation of Prudhoe Bay in other profitable ventures, does not have the same opportunities for doing so nor the same freedom to do so as a private enterprise. The state has responsibilities to its citizens and the citizens of the nation that the private enterprise does not.

First of all, there is the matter of the absolute value of the recovered oil itself. A difference in a percentage point in recovery can be sacrificed with impunity in ordinary reservoir operation in past times if a significantly higher profitability is achieved. A percentage point in the recovery of oil from Prudhoe Bay represents 200 million barrels, a major oil field in itself.

Secondly, just what is the trade off between the cost of gas reinjection and water injection even as proposed by the operators, and what are the corresponding recovery efficiencies for such base case operations?

Thirdly, are the interests of the State and the Nation better served by stretching out the period of utilizing the natural gas from Prudhoe Bay? In the possible absence of future discoveries, say from THE Beaufort Sea, the present crude oil pipeline will not be highly utilized after fifteen years of operating Prudhoe Bay. Crude oil production begins to decline precipitously after some eight years of operation, and within fifteen years the production rate is down to less than 500,000 barrels a day. Should consideration be given to using the crude oil line for two phase flow of gas and oil at that time with gradual increases in the gas oil ratio of the throughput?

The gas arriving at some convenient destination within Alaska could be converted to liquid fuels and petrochemicals from which the State and the Nation will derive greater ultimate economic and social benefits than those to be gained by delivering the gas at this time at great cost to the lower 48 for mere burning!

These are vital matters to be examined by the state, and such examination is possible only by having available a more comprehensive series of reservoir performance predictions, economic studies, and gauges of practicality.

In concluding this review of the analysis of the prediction of recovery efficiency, a comparison of some of the results of van Poolen and the operators will bring into final focus some of the problems in appreciating the differences between the results of various mathematical simulations.

For the van Poolen cases which are most closely comparable to the preferred plan of the operators (Runs 3A and 5A) an average recovery of 41% is predicted compared to 39% for the Exxon runs 6 and 7. (The 2% difference is of the order of 400 million barrels.) However, considering the differences in the two models it is surprising that the results are so close. The biggest difference between the two models, from our somewhat arm's length remoteness, is the assumed residual oil saturations to gas invasion. As stated earlier, the residual oil saturation in the operators' model can be driven to quite low values by the continuing invasion of gas whereas in the van Poolen model there is an end point saturation of 32%. Since recovery is proportional to pore volume swept multiplied by the reduction in oil saturation, van Poolen must predict a considerably higher sweep efficiency than do the operators. Van Poolen's higher sweep is consistent with the fact that ~~he~~ THEY built less realism into ~~his~~ THIER model than did the operators; the simplifications ~~he~~ THEY made could well lead to APPARENT improved sweep efficiency IN THE MODEL OUTPUT. What is startling is that these two effects almost exactly offset one another, and that the Division of Oil and Gas did not bring this matter up for discussion at the Anchorage hearings.

The fact that two different schemes provide answers of such similar numerical value cannot be used to indicate that the common result is correct. Attention must be given to the nature of the input data, the nature of the reservoir model, the scheme for solving equations, and the exact nature of the operating conditions imposed on the model reservoir behavior. Again, we point to the necessity of production data for calibrating these models. When predictions are made before the accumulation of real reservoir performance data, it is necessary to leave options open for the operator to respond to the accumulation of real knowledge about reservoir performance.

Chapter VI.

ACCUMULATION OF RESERVOIR DATA, PERFORMANCE OF RESERVOIR TESTS, AND SURVEILLANCE OF PRODUCING OPERATIONS

No mortal now knows exactly how the Prudhoe Bay Field will perform. This fact has been exemplified and stressed many times in the previous discussion. None of the parties involved would likely question THE many uncertainties in reservoir performance which need to be dealt with. An extensive and thorough program of test and measurement and general surveillance of reservoir operations has been laid out to provide the necessary data to unravel these mysteries.

The planned program of data collection to which the operators have agreed is specified in Rules 1-15 in Conservation Order No. 145. These rules call for a continuing program of testing well performance and collecting a large body of data indicative of how the reservoir is performing. Pressure surveys, gas-oil ratio tests and productivity profiles (spinner surveys to indicate where produced fluids are entering the well bore) will provide a growing volume of data indicative of what is happening in individual wells. A thorough program of well logging is planned to track the movement of the gas/oil and the water/oil contacts throughout the field.

Interpretation of these latter two sets of data will indicate the degree of gas and water coning and the effect of permeability barriers. These data will be particularly valuable in selecting optimum perforation intervals in new wells and in planning workovers of existing wells. Reservoir material balance calculations, initially, and later reservoir simulation studies INCORPORATING ~~made using~~ these data will begin to reveal the vitally important values of residual oil saturation and to throw light on the many other uncertainties built into the reservoir prediction models. All of this information should be of particular value in planning and implementing water injection.

These rules also provide for minimum well spacing of approximately 100 acres, prohibit gas flaring, limit pool offtake rates and specify safety practices to be followed in drilling and producing wells. The procedures to be followed in cementing and casing a well are also specified, and particular concern is given to avoiding serious problems with the permafrost.

Surprisingly omitted from these completion procedures was a provision to test the integrity of the cement seal through the productive formation. For the benefit of those uninitiated in oil well completion procedures, when a well is drilled a piece of pipe (called either a casing or a liner depending on whether it does or does not extend to the surface, respectively) is inserted through the hydrocarbon bearing strata and cemented in place. A sufficient volume of cement is forced into the annulus between the pipe and the rock face of the productive formation to fill the annulus to a level of at least 500 feet above the highest potentially productive formation (Rule 3). The cement must overlap by at least 100 feet the next deepest casing string (obviously of larger diameter) (Rule 3). Perforations are simply holes blown through this deepest section of pipe by bullets or jets of metal fired at selected depths.

In order to have complete control of the producing well the cement must bond securely to both the outer wall of the pipe and the rock face. A cement bond log can be run in the well to determine if the seal is complete. If a faulty section is detected, a hole is cut in the pipe opposite and more cement is squeezed under high pressure into the annular region outside the pipe. The operators indicated that such logs are run and the drilling reports which we examined confirmed this. It is surprising, however, that running and carefully interpreting a cement bond log in all wells, both injection and production, is not incorporated in the completion rules. A faulty cement seal can greatly exacerbate gas coning since a leak between the casing and the productive formation can provide a conduit with effectively infinite permeability from the gas cap into the perforations. (A noise log or a temperature log will frequently reveal such leakage behind the casing in a producing well.)

~~In~~ At the Anchorage hearings in May the operators testified to their plans to conduct all of the surveillance activities called for in Conservation Order No. 145. In our discussions with them they indicated that in their judgment they have assigned sufficient experienced engineers to adequately monitor performance and to interpret the data so that it can be put to use to improve the operation of the reservoir.

The Division of Oil and Gas was not, however, adequately staffed at the time of our discussion with them in July to handle its surveillance responsibilities. They were actively recruiting FOR an ~~experience~~ WITH engineer 5 to 10 years experience to be assigned full time to this watchdog activity. It seems a fair question to ask whether the Division will, after it recruits the one person for whom it is now looking, have sufficient capability to do its job properly. Attempting to answer this question requires careful consideration of what the Division's role should be. Certainly, it should not be envisioned that the Division should approach the level of staffing required to duplicate the reservoir engineering studies performed by the operators. The engineers carrying out these studies for the operators are experienced and are backed up by large staffs of specialists and research scientists providing a complete cross-section of talent and experience. On the other hand, very few would argue that Alaska's interests are being properly looked after if its watchdog group is so thinly spread and lacking in the required competence and skills that all it can effectively do is rubber-stamp the operators proposals.

Even without even beginning to duplicate the operators' efforts, there remains a very large amount of work which the Division must do to properly oversee operation of the Prudhoe Bay Field. This work falls into three categories: on-site inspection and supervision; data acceptance, review, organization and storage; and independent interpretations and analyses. The first category is an essential part of knowing that things are being done properly and that accurate data are being collected; regular visits to the field are also necessary to keep an engineer tuned in to the significant problems being faced and ~~to~~ how the data collected relate to these problems. The second category is to make certain that the data are reasonable and that the measurements seem to be made correctly. Because the volume of data to be delivered to the Division is large, procedures for storing it in a readily retrievable and useful form need to be devised. The last category feeds off of the first two; the Division will need to perform independent analyses to arrive at its own interpretations.

The charter of the Division does not call for it to consider economics in its analyses, But at some point such considerations must come into its deliberations because (a) the operators' proposals are necessarily developed against a back drop of economic factors, and (b) the people of Alaska are interested in achieving the maximum economic benefit from their interest in Prudhoe Bay.

In addition, the Division of Oil and Gas, the Legislative Affairs Agency, or some other agency or agent of the State must be assigned the role of assessing the end use and utilization of the state's resources in Prudhoe Bay (and other oil and gas and mineral accumulations) that are not yet committed.

Finally, the Division of Oil and Gas, or an appropriate research board should pursue under their own auspices or jointly with lease holders and the Federal Government, research and development programs that will increase the absolute recovery of wealth from the Prudhoe Bay field and the maximum conversion of the crude oil and gas into economic and social benefits for its citizens and those of the other forty-nine states.

Considering the enormous treasure in the Prudhoe Bay Field, and the magnitude and multiplicity of the tasks which must be performed to insure its maximum utilization, there is considerable doubt that the current staffing plans of the Division of Oil and Gas are adequate. Not only must the staff~~ing plans~~ of the Division be increased, but its scope and responsibilities greatly extended or supplemented by other agencies of the State of Alaska.

DRAFT

Chapter VII

CONCLUSIONS

1. Concerning the adequacy of the review of the operating plans submitted by the operators and the studies prepared on behalf of the Division of Oil and Gas of the State of Alaska.

It has been concluded on many counts that the results of the simulation studies presented to the State by the operators and others prepared for the Division of Oil and Gas have not been as adequately reviewed as required to protect the interests of the State in their great resources in Prudhoe Bay.

In reaching this conclusion we do not impugn that the studies are manifestly incorrect or improperly conceived. We appreciate that they are built on an input which can be debated, operating conditions which can be varied, and a reservoir model that can only approximate the real Sadlerochit reservoir.

The studies prepared by the operators emphasized the plans which the operators had selected based, in part, on their interpretation of laboratory tests and their need to maximize their interests. Theirs is a proper course of action. The studies prepared on behalf of the Division of Oil and Gas of the State, although more comprehensive in the range of variables addressed, were not sufficiently internally consistent for positive trends in the variation of operating characteristics to be adequately revealed.

There are sufficient differences between the van Poolen studies and those of the operators so that the Division of Oil and Gas should have addressed these differences, despite the differences in the sophisticated and apparent realism of the models. We call attention, specifically, to the differences in the estimates of the original oil in place in the reservoir, and the differences that are implied ~~of~~ IN the effect of gas sales on ultimate oil recovery even under water flooding conditions. Both the van Poolen and Core Laboratories studies indicate a substantial effect of increased gas sales on decreasing oil recovery.

We have attempted to show throughout this report the basic limitations of reservoir performance predictions in the absence of actual reservoir performance. Because of these limitations, it is not possible to make sufficiently accurate performance predictions in the absence of some performance data to history match, or calibrate the model and the simulation scheme chosen. We are impressed, as should all Americans, with the enormity of the Prudhoe Bay reservoir and that at this time it contains some thirty percent of the reserves of liquid fuels of the nation. Whereas a difference of one percentage point in recovery efficiency for lesser reservoirs in past times could be sacrificed with impunity for greater convenience in operations, or greater profitability, a one percentage point difference in the recovery of crude oil from Prudhoe Bay is some 200,000,000 barrels. Only some sixty fields with larger ultimate recovery than this volume have ever been discovered in the United States, and only three (including Prudhoe Bay) since 1960.

We have therefore concluded that the State should make no commit~~t~~ment beyond that which is required for the orderly development of the field to permit attainment of crude oil production at the rate required for the economic operation of the crude oil pipeline.

The State should seek to have prepared an internally consistent set of reservoir performance predictions that explore the effect of individual variables, economic costs and a wide range of operating conditions. Such base case information is necessary for informal assessment of preferred operating plans.

2. With respect to the staffing of the Division of Oil and Gas of the State of Alaska and other agencies of the state that will be required to maximize the wealth of Prudhoe Bay for the citizens of the State and the Nation.

The present and planned staffing of the Division of Oil and Gas is inadequate for the role the Division of Oil and Gas must play in order to provide the necessary surveillance, data collection, and independent analysis of the performance of Prudhoe Bay.

In addition to these conventional activities the State should add to the responsibilities of the Division, or assign to currently activated agencies or newly created ones, the tasks of economic assessment of various operating plans for the Prudhoe Bay Field, and of the economic and social benefits of the end use and utilization of the oil and gas that is not already committed; further, THE STATE SHOULD ~~to~~ sponsor and participate in research and development programs that hopefully will increase the recovery of crude oil from Prudhoe Bay beyond that which can be recovered by conventional technology.

Whereas increased staffing on all counts is needed, the greatest urgency resides in developing a sufficiently competent staff to exercise proper surveillance and the informed collection of field performance data. Data can never be collected after the fact. At the same time, such surveillance and data collection activities must be undertaken without creating an unnecessary burden on the operators nor in interfering with the orderly development of the field.

3. With respect to the State's evaluation of ways and means for maximizing their interests in the wealth of Prudhoe Bay on behalf of their citizens.

The operators have presented the conclusions of their studies which show that the sales of gas and eventual implementation of water flooding will not interfere with realizing a high recovery of crude oil from the Sadlerochit reservoir. The State has not studied the possibility that there are other alternate and more beneficial uses of the gas for their account which will not interfere with the interests of the operators, and simultaneously maximize the total recovery of fuels, particularly liquid fuels for the ~~N~~ nation.

There is serious doubt in our minds that the gas can be marketed profitably in a free market or that such sales of gas to the lower forty eight states is in the best overall interests of the state and the nation.

Estimates of the cost of the proposed gas line abound. We are impressed by recent estimates ~~that~~ WHICH suggest THAT a cost of twenty five billion dollars or more would not be surprising. A gas rate limited to two billion cubic feet a day would require a transportation cost of $5 per thousand cubic feet in order to return an investment of twenty five billion dollars at a 15% discounted cash flow. This cost is in the absence of any operating costs, taxes, and purchase price of the gas at the well head. Gas, burdened with such a transportation cost would probably not be competitive. Other sources of gas could well become available at such costs. Further, the two billion cubic feet a day constitutes less than 5% of our nation's consumption at this time; a marginal source by itself.

It appears necessary therefore if the State is to wisely make use of its resources that it set about to ascertain the realistic, anticipated costs of pipe line construction and the possibility that such a transportation system for the gas would be built. There are alternate and possibly more beneficial uses for the gas.

In the absence of future discoveries of crude oil which can be transported by the present crude oil line from the North Slope to Valdez, throughput will begin to decrease precipitously within eight years and within fifteen will be less than 500,000 barrels a day. It may be possible at that time to use the crude oil line for two phase flow of oil and gas. Ultimately, some of the gas could be liquefied and transported to West Coast destinations by tankers.

In addition, the gas could be converted in part to liquid fuels (alcohol) capable of being transported through the crude oil line. In addition, the gas could be converted to petrochemicals. There is little question about the range of possibilities for using the valuable resource of gas in many ways, any one of which and all together would probably represent far greater utilization of the state's resources for the ultimate long range benefits to the citizens of the state and the nation.

The state would be remiss in not embarking upon a full fledged study of the potential of alternate utilization of the gas in lieu of permitting it to be shipped at great cost to the lower forty-eight for mere burning at this time.

98-069 O - 78 - 26

4. With respect to ~~the~~ research and development programs to increase the recovery efficiency beyond that attainable by conventional technology.

Some twelve billion barrels of crude oil are likely to remain in the reservoir following the time when the field reaches its economic limit sometime after the turn of the century by the application of only conventional technology. It has not been sufficiently impressed on the citizens of the United States that Prudhoe Bay will have spent its maximum potential for producing crude oil within eight years, and thereafter begins a precipitous decline, reaching a value of less than 500,000 barrels a day within fifteen years. Further, that conventional technology will leave amount of crude oil then will be extracted. This oil will remain in the reservoir because of the nature of the fractional flow curve (see Appendix). An increasingly large and uneconomic quantity of water or gas would be required to recover this residual oil.

A great effort is underway in the United States, in part sponsored by the United States Energy Research and Development Administration (ERDA), seeking processes for recovering crude oil left behind by conventional technology. Success to date has been limited except in the use of steam injection techniques in California's heavy oil reservoirs.

Because of the reported high vertical permeability (the parameter that recommends gravity drainage as the production mode), there is ~~any~~ an enhanced recovery process, carbon dioxide injection, that possibly may succeed in Prudhoe Bay. Carbon dioxide injection is being actively studied for the recovery of residual oil by many large oil producers, ~~U. S.~~ ERDA, and universities.

Carbon dioxide under high pressure is miscible with many crude oils. The density of this liquid, a function of pressure and temperature, is of the same order of magnitude as crude oils. If such miscibility of carbon dioxide with Prudhoe Bay crude can be demonstrated, then significant recovery of the residual oil from Prudhoe Bay field is conceivable. The thick sand interval and high permeability would recommend consideration of a gravity stabilized process in which the carbon dioxide is injected at the gas-oil contact to sweep the residual oil downwards. Mixing with the methane gas cap would be restricted because of the far greater density of carbon dioxide. Such a stabilized process is probably the most effective way for implementing the carbon dioxide recovery process.

We do not know of the existence of any large, naturally occurring quantities of carbon dioxide on the North Slope. The gas in Prudhoe Bay does contain some 12% of carbon dioxide which is not sufficient nor can it be made available in a sufficiently timely fashion to be used in such a recovery scheme. A search for naturally occurring carbon dioxide could well be undertaken.

Produced crude oil could be burned to produce carbon dioxide. We would roughly estimate that combustion of one third of the additionally produced crude oil would provide the required carbon dioxide for such a scheme. Already, in tertiary recovery operations in California, Venezuela and other places in the world one third of the additionally produced crude oil is used to generate steam for profitably producing viscous crudes.

The ultimate value of a delivered barrel of Prudhoe Bay crude may be so much greater than its on-site value (it already is so), that the cost of burning two billion barrels of the six that might be produced by such a scheme would be more than offset by the four billion barrels of saleable crude.

Values of the process could be further enhanced by concomitant use of the energy liberated by combustion. For example, a 700 mile power transmission line to Southern Alaska is not out of the question. Some of the carbon dioxide could be supplied by gas reforming with the "by-product" hydrogen being used in the production of petrochemicals. Additionally, a combination of carbon dioxide, power and hydrogen coild be manufactured by partial gasification of the crude oil or of the heavy ends of the crude.

Again, we would summarize our views by stating that there is conceptual technology for increasing the recovery of crude oil from Prudhoe Bay, and that such methods could be compatible with other technology for enhancing the long range utilization of the resources of the State for the benefit of the State of Alaska and the Nation. We believe the State should pursue the definition, development and implementation of those programs, ~~that~~ which will achieve the most favorable results while still promoting the orderly and prudent development of the Prudhoe Bay field.

DRAFT

APPENDIX

THE MECHANICS OF OIL PRODUCTION

The sedimentary rocks that constitute the Prudhoe Bay reservoir are comprised of sandstones, conglomerates and shales that were washed down from mountains to the north and deposited by a southward flowing river system in deltas and rivers. The reservoir is comprised of several zones, each having been laid down under relatively constant geological conditions. They vary from relatively clean sands deposited in a main river channel to the finer clays, since compacted to shales, deposited in quieter bays. Thicknesses of conglomerates consisting of coarse sands, even pebbles, interbedded with shales are also found.

It is obvious that the Prudhoe Bay reservoir is not a uniform entity. This nonuniformity is a hallmark of practically all crude oil reservoirs. As a result there is not any singular and unique value for any one reservoir parameter. The values for porosity (fraction of the rock comprised of pores which can be filled with oil, gas and water) will change foot by foot and probably inch by inch. Only a most likely or average value derived by statistical analysis, can be assigned to any of the pertinent parameters that govern fluid flow and recovery efficiency. To each assigned value must be appended a designation of its likely variation.

The values of the most important parameters, moreover, cannot be directly measured in the reservoir; rather, the values must be calculated or inferred from some other measurement.

For example, the porosity of the reservoir (the fraction of a rock layer's volume which can be filled with oil, gas and water) is a most important parameter for the estimation of the original oil in place in the reservoir. Although there are down-hole tools which can investigate this parameter, these tools must be calibrated against a piece of rock, a core, cut from the formation by special coring tools driven by the drill string. (In the case of Prudhoe Bay, the use of the preferred down-hole tool for reliable porosity estimation was found to be inapplicable because the reservoir rock contains unusually dense materials.) Cores used for reference calibration are taken to the laboratory, "cleaned up", and their porosity measured under conditions which attempt to restore the subsurface environment of the reservoir. It is obvious that such measurements can only approach the true in-situ values. The calibration is effected by comparing the down-hole tool's response in the section from which the core was taken to the laboratory-determined value.

Another parameter, even more important in affecting recovery efficiency and production rates, is the permeability of the rock to oil, gas and water when the rock contains (is saturated with) varying amounts of oil, gas and water. Permeability is a measure of the ease with which fluids will flow through the reservoir under a given pressure gradient (pressure drop per foot of reservoir) after allowing for differences in the viscosity of the fluids (viscosity is a measure of the thickness of the fluids; molasses has a high viscosity, water has a low viscosity). Again, values of permeability are usually measured on "cleaned up" cores, which have been resaturated with oil, water and gas in various proportions by any one of several procedures. Measurement of fluid flow rate through the core and the corresponding pressure drop across the core provides the data from which permeability is calculated.

The permeability of a core in the laboratory shows intuitively unanticipated behavior. If the rock is filled with only water, the permeability to water is found to be essentially the same as that to oil. However, when the core is filled with the two immiscible fluids (oil and water do not mix, they are immiscible), it is found that for a given pressure drop the total rate of flow through the core is significantly less than the rate of flow when only one fluid is present. The loss in permeability is a function of the saturation (see Figure 1).

In addition to the total flow being less than that for either fluid by itself, the fraction of water and of oil in the stream flowing through the core changes systematically with the saturations of oil and water in the rock. Figure 2 shows the changes in the fractional flow of water with changes in saturation corresponding to the data of Figure 1.

An examination of this figure shows that at some maximum saturation of water, corresponding to a minimum saturation of oil, oil will no longer flow in the rock. Thus, if water

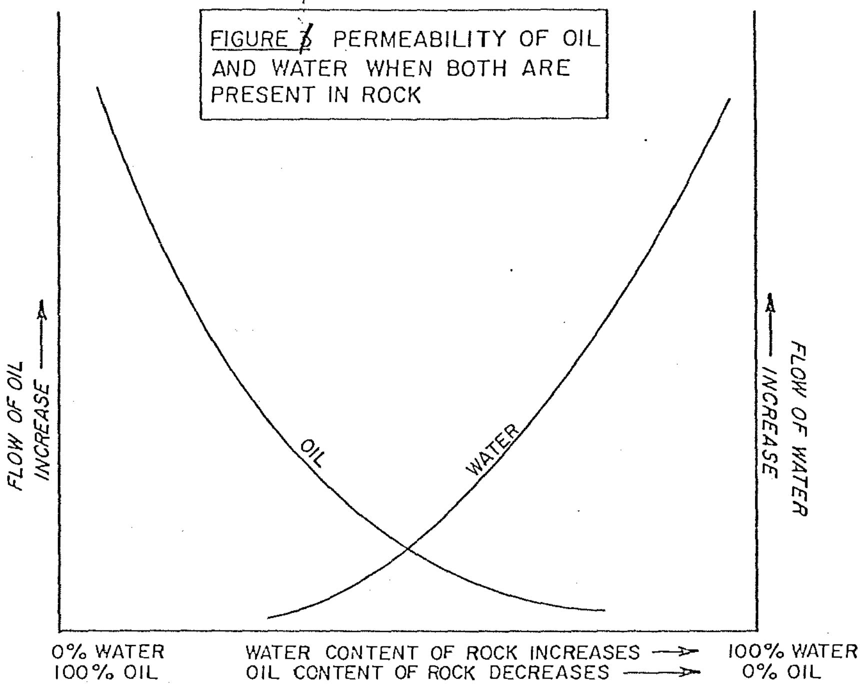


FIGURE ~~3~~ 1 PERMEABILITY OF OIL AND WATER WHEN BOTH ARE PRESENT IN ROCK

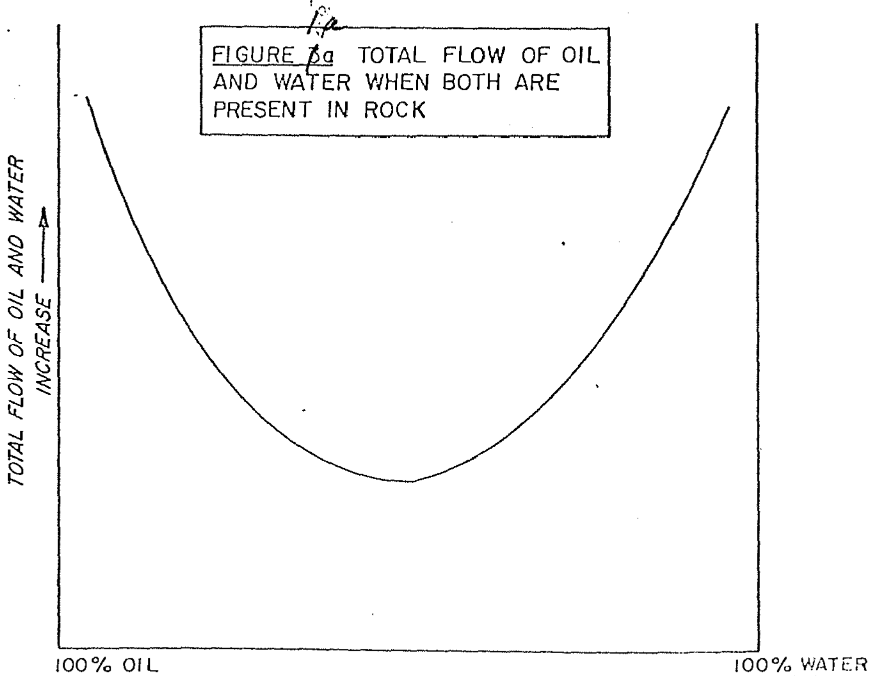
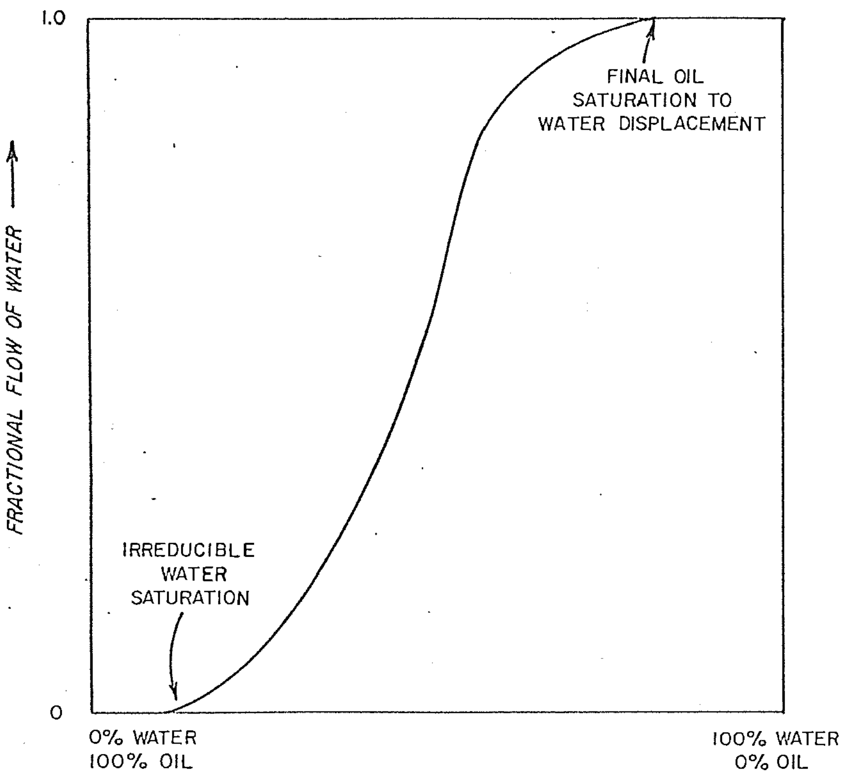


FIGURE ~~3a~~ 1a TOTAL FLOW OF OIL AND WATER WHEN BOTH ARE PRESENT IN ROCK

FIGURE ~~4~~ 2

FRACTIONAL FLOW OF WATER
IN OIL— WATER SYSTEM

(FRACTIONAL FLOW OF OIL = 1-FRACTIONAL FLOW OF WATER)
(ASYMPTOTIC APPROACH TO FINAL OIL SATURATION)



invasion was the dominant mechanism for displacing oil in the reservoir there is some level of oil saturation which cannot be reduced. Obviously, this level sets a theoretical limit to the amount of oil that can be recovered by water displacement. Further, the amount of water required to reach this irreducible minimum value for the oil saturation is governed by the curvature of the fractional flow curve as the water saturation approaches its maximum value. If the curve reaches its maximum value abruptly, as in Figure 3, it will take a relatively small amount of water throughput to reach the irreducible oil content. On the other hand if the end point is reached gradually (asymptotically) as in Figure 2, large volumes of water will be required to reach the irreducible minimum oil saturation.

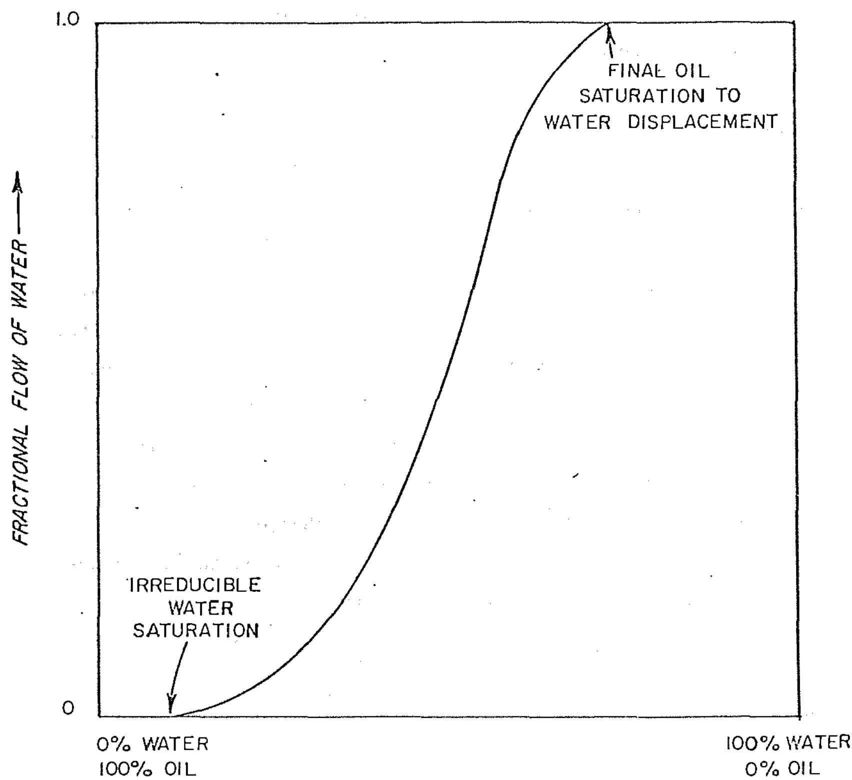
A similar relationship holds for the simultaneous flow of oil and gas. Now, however, the porosity available to the oil and gas is less than the total porosity of the rock. Some of the porosity will be filled with an irreducible amount of water. The presence of this water results from the fact that most minerals are wetted by water in preference to oil, and is a reminder of the fact that most sedimentary rocks that contain oil were laid down in a marine environment. At a later time when the oil migrated from the source beds into the rocks, some 10% to 30% of the water in the pore space remained behind primarily in the form of films of water around the rock grains.

The saturation at which gas flow is initiated is known as the critical gas saturation, and is usually only 1 to 5% of the

FIGURE ~~2~~ 3

FRACTIONAL FLOW OF WATER
IN OIL—WATER SYSTEM

(FRACTIONAL FLOW OF OIL = 1 — FRACTIONAL FLOW OF WATER)
(ACUTE APPROACH TO FINAL OIL SATURATION)



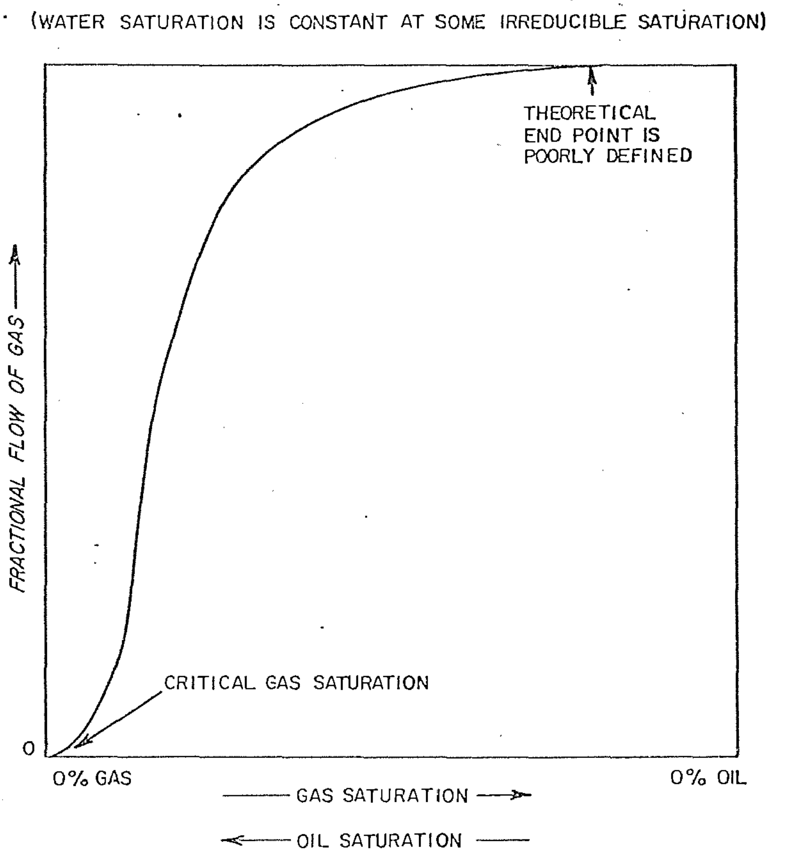
porosity. The fractional flow of gas (Figure ~~6~~ 4) not only is initiated at low gas saturations, but also rises very rapidly with further small increases in gas saturation. As a result, the final approach to the maximum gas saturation (minimum oil saturation) is more gradual than in the case of water displacing oil. Indeed, there is much question as to whether there is any true residual oil saturation when gas displaces oil in the presence of water-wetted rocks. However, because of the asymptotic approach of the curve to its maximum value, very large volumes of gas must be put through the core to reach the minimum (zero ?) value of residual oil. From a practical point of view, therefore, there is a real residual oil saturation to a gas drive since infinite volumes of gas cannot be put through the core.

Another property of reservoir fluids that must be kept in mind is their compressibility. It is well-known that the volume of a given amount of gas will be decreased if the pressure on the gas is increased (a parallel is what happens when one sits on an air cushion). It is not always realized that liquids such as oil and water are also compressible. Of course, the change in volume of a liquid for a given change in pressure is much smaller than in the case of a gas. Although the compressibility, or inversely, the expandability of oil and water under a reduction in pressure is small, if the pressure is decreased on a very large volume of water the absolute expansion will be very large indeed. Water expands only three one hundredths of

4

FIGURE 6

FRACTIONAL FLOW OF GAS
IN GAS-OIL SYSTEMS



one percent when the pressure is reduced by 100 pounds, but if the initial volume of water is a trillion barrels the absolute expansion is 300 million barrels. If the pressure is reduced by a thousand pounds, the absolute expansion is three billion barrels.

Crude oil contains dissolved gas (associated natural gas), and the amount of gas dissolved is a function of pressure. The volume of a given weight of "pure oil" will increase as the gas is dissolved in it, and will, of course, decrease as the gas is liberated.

In a reservoir such as Prudhoe Bay where a gas cap exists the crude oil has dissolved all the gas it can at the reservoir pressure. Were it not so saturated, the free gas would be continuing to dissolve in it until equilibrium was reached. Therefore, any reduction in the pressure on the Prudhoe Bay reservoir will lead to the liberation of gas. This decrease in pressure will of course happen when fluids are withdrawn (produced) from the reservoir. Some of this gas is liberated within the reservoir, dispersed in the oil. The fractional flow of oil in the produced fluids will therefore begin to decrease according to the fractional flow concepts presented above. The decrease in oil flow will be proportionately far greater than the increase in gas saturation. Since the volume of oil shrinks as gas is liberated, the oil saturation in the reservoir decreases even more rapidly as gas is liberated. The fractional flow of oil further suffers, and gas production begins to increase rapidly.

It is obvious that other factors being equal, it is best to produce a reservoir at as high a pressure as possible to secure the most favorable flow of oil into the reservoir.

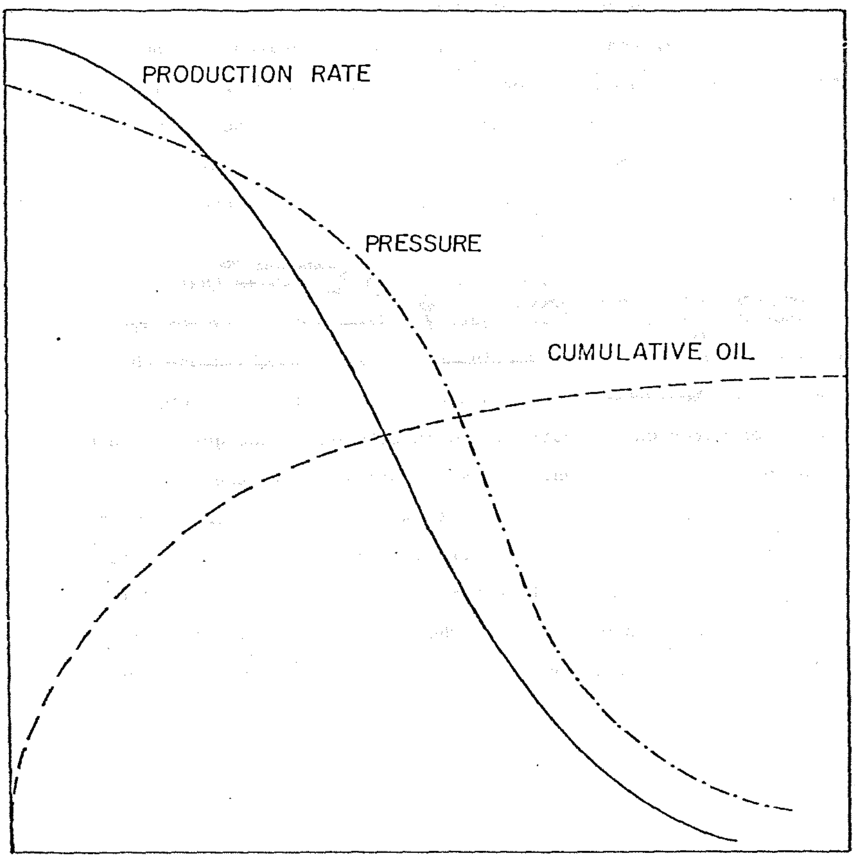
It is of course impossible to avoid some pressure reduction in the reservoir. It is this very drop in pressure which provides the energy for the oil to flow into the bore hole of a well. Production can be seen to be a self-defeating process. The withdrawal of oil from the reservoir lowers the pressure, a reduction in pressure decreases the available energy for additional flow, the reduction in pressure liberates gas and shrinks the oil which further lowers the flow rate of oil into the well, and when shrunken oil is left behind in the reservoir, the reservoir oil contains a higher content of "pure oil". A crude oil reservoir can never produce oil today better than it did yesterday (Figure ~~7~~ 5).

A thick, vertical slice of a reservoir (Similar to ~~such as~~ that of Prudhoe Bay but without the shale layers) is depicted in Figure ~~8~~ 6. ~~(In this case we assume no thin layers of shale occur in the oil band which is not the case in Prudhoe Bay.)~~ There is a column of gas on the top, a column of water on the bottom, and in between is the gut of the reservoir, the oil column. There is some water in the oil column, most of it at an irreducible minimum saturation at which it will not flow. Following drilling, and casing the well, the liner (casing across the oil saturated interval) is perforated with explosive jets or bullets. The perforating fluid in the hole is then circulated out; the pressure at the bottom of the

5

FIGURE ~~7~~

PRODUCTION HISTORY
A DEPLETION RESERVOIR



TIME →

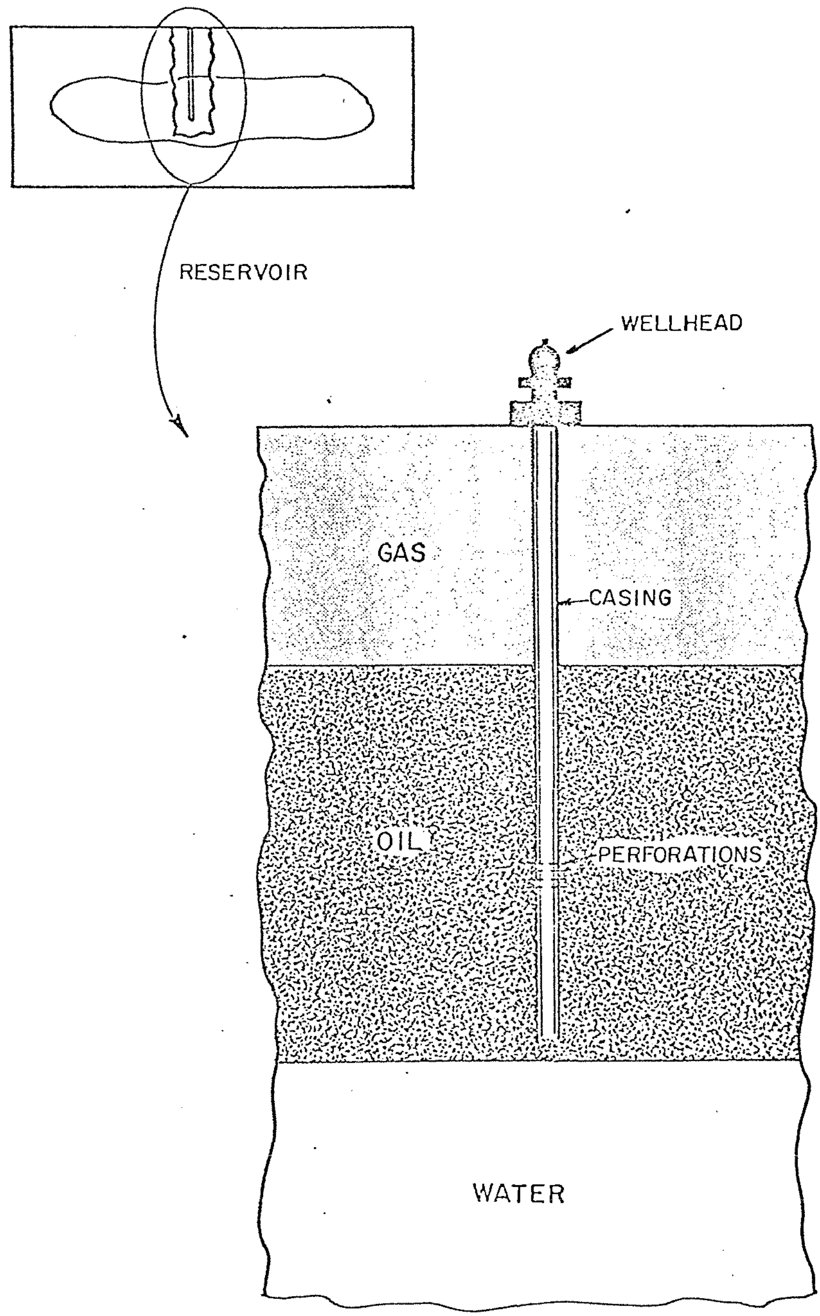


FIGURE ~~8~~ 6 ORIGINAL FLUID LEVELS

98-069 O - 78 - 27

hole is allowed to fall below that of the reservoir. The resulting difference in pressure results in a flow of oil out of the reservoir into the bore hole. As the oil reaches the lower pressure of the bore hole, gas comes out of solution. The gas continues to expand upwards towards the lower pressure of the wellhead. Because the tubing in the well through which fluids are conducted to the surface has a smaller diameter than the casing, the oil entering the well is entrained by expanding slugs of gas and carried to the surface. The well is said to flow naturally.

Gradually the pressure begins to drop throughout the reservoir and the oil-gas interface begins to fall. The space formerly occupied by oil is replaced by the gas, which expands as reservoir pressure drops (Figure 7 ~~8~~). How much oil is left behind at this descending interface between the oil and gas? If the descent was infinitely slow, the oil left behind might well be close to zero; recovery would be nearly 100%. Under practical conditions, the rate will never be infinitely low and the residual oil saturation will be determined by the curvature, or asymptotic approach to the ultimate residual saturation (see Figure 4 ~~8~~) and the rate chosen for withdrawal of oil.

As a result of the pressure drop within the reservoir, some gas will be liberated from the oil as the oil flows to the perforations. This gas will tend to rise because of its low density towards the gas cap. This is known as gravity segregation and will occur all the more rapidly if the vertical

FIGURE A

FLUID LEVELS FOLLOWING DEPLETION BY GAS CAP EX-PANSION

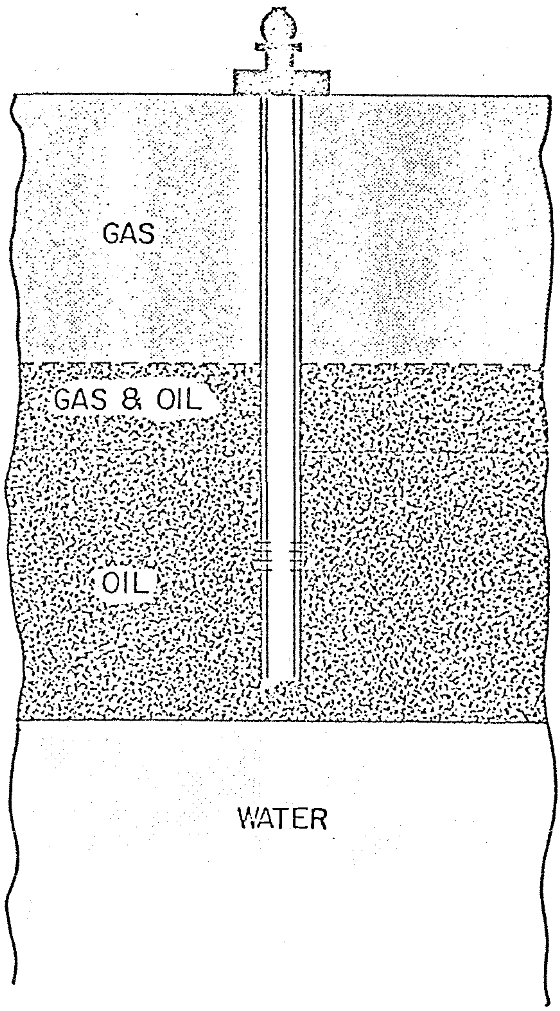


FIGURE ~~10~~ 8

GRAVITY SEGREGATION OF LIBERATED GAS

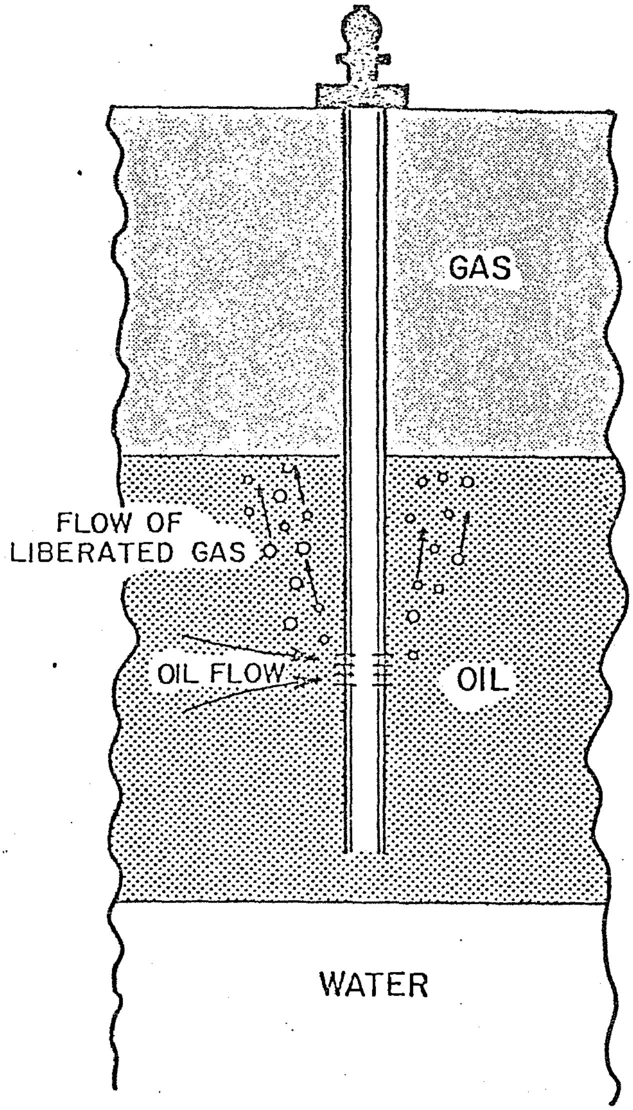
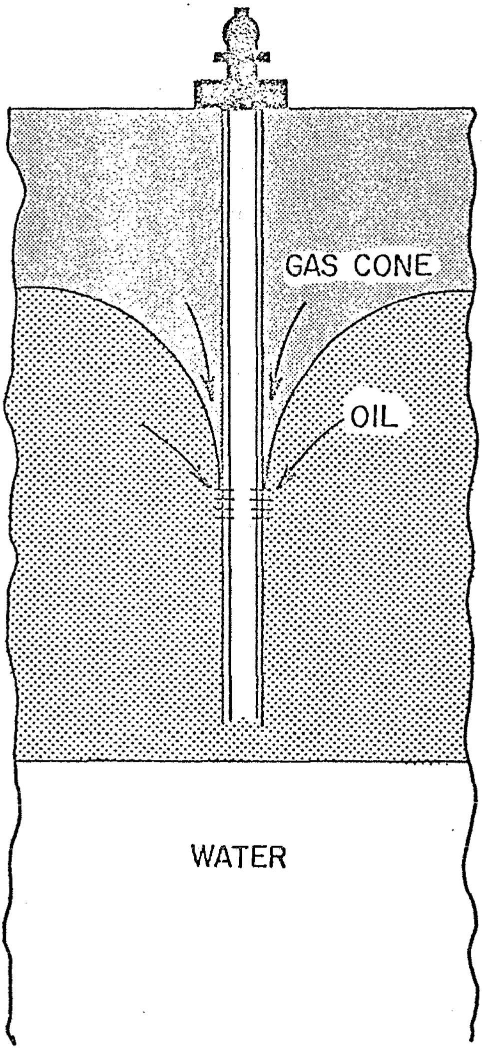


FIGURE ~~11~~ 9

CONING OF GAS INTO A PRODUCING WELL



permeability of the rock is high. This is good because even less gas will be produced than if segregation did not occur, and the gas cap is fortified (Figure ~~10~~ 8).

If the pressure drop between the oil column and the perforations is high, due to a high production rate, the gas cap will be sucked down into the perforations (Figure ~~11~~ 9). This is known as gas coning; it is to be avoided, in general, because it results in a loss of energy available to displace additional oil into the well.

Gas coning may be reduced by lowering the velocity of the oil towards a well bore. Thus, coning can be restricted by decreasing production rate. If some given rate of production must be maintained from a reservoir, then coning can still be restricted by drilling more wells. This operation is known as infill drilling. An intermediate solution would be to seal off the existing perforations and create new ones lower down in the oil column so that the gas cap will not be sucked into them until a later time.

The perforations are not put at the bottom at the beginning of production at Prudhoe Bay to avoid sucking the water up into them (water coning). Of course, the water column itself will be expanding as the reservoir pressure is reduced. A large water leg would result in significant expansion leading to a rise in the oil-water interface; displacement of oil by water (a natural water drive). In many reservoirs a natural water drive originating from a water column, much bigger in size than the oil column, results in oil displacement at but a tiny drop in reservoir pressure. Historically, such natural water drive reservoirs in the United States have given the greatest recovery efficiencies the industry has encountered. Some reservoirs, in East Texas and Louisiana, had recoveries as high as 70%.

For a reservoir slice as depicted in Figure ~~8~~ 7 with a large and strong aquifer contiguous with the oil column, there would be no choice in the mode of operating the reservoir. The gas cap pressure would have to be maintained to prevent oil from being pushed up into it.

If the aquifer is limited and weak, a choice must be made: to allow the gas cap to expand or institute a water drive by injecting water. The decision must be made based on the following parameters:

Firstly, the residual saturation of oil left behind an expanding gas cap vs. the residual saturation left behind by encroaching water.

Secondly, the comparative costs of injecting water and the need for and costs of reinjecting gas.

It has been concluded by the Operators that the natural water drive at Prudhoe Bay is insufficient to invade the oil column at rates comparable to the desired rate of oil production. Therefore, a choice had to be made on the comparative advantages of gas cap expansion vs. waterflooding.

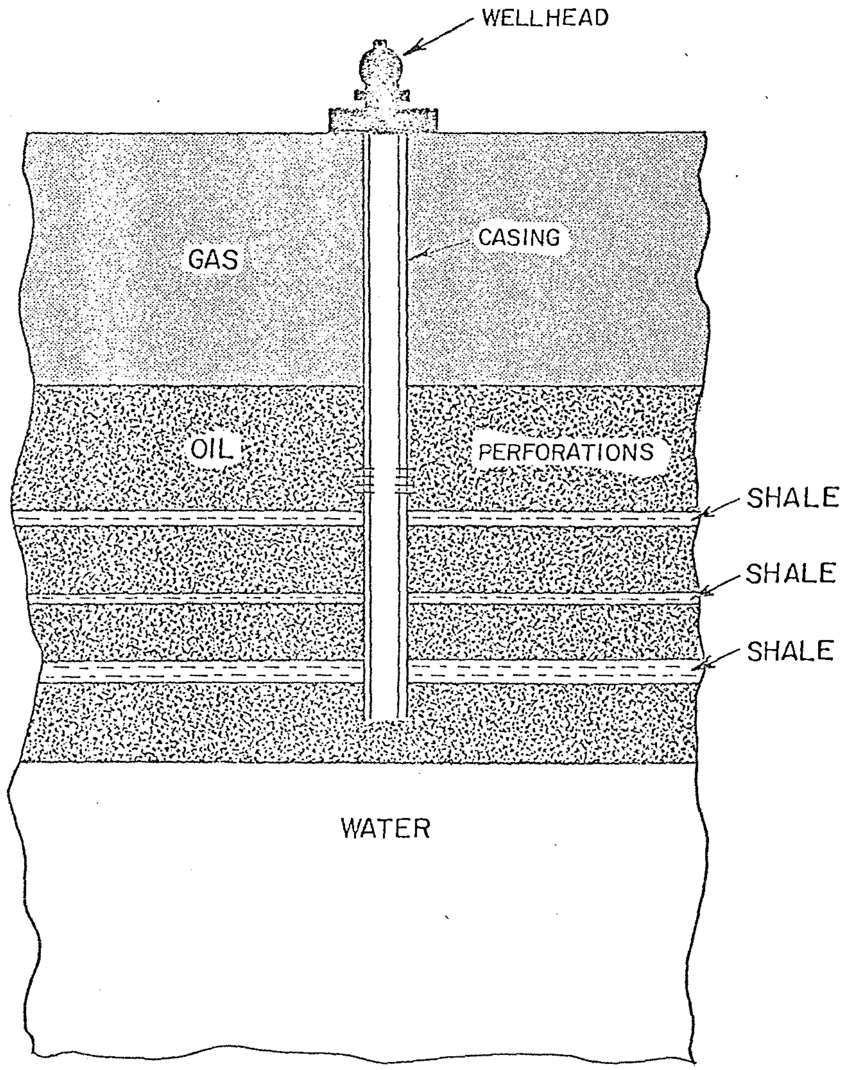
Should the sands not be continuous as depicted in Figures ~~8~~ 6 and ~~9~~ 7, but interbedded with impermeable shales, then gas cap

(FIG. 10)

expansion will be stopped by such discontinuities and the gas cap can be considered virtually a separate reservoir. Under these conditions the oil between the shales would have to be produced by the relatively inefficient solution-gas depletion process, supplemented by very early (horizontal) water displacement. Of course, the separation by shales cannot be as absolute as suggested. The very existence of one gas cap and a somewhat common water level in the Prudhoe Bay reservoir suggests that vertical communication is at least high enough for gravity segregation to have occurred over geological time. It is obvious that the exact definition of the extent of vertical communication is required to choose a proper operating plan.

FIGURE 10

RESERVOIR WITH SHALE FORMATIONS



Senator DURKIN. The hearing is adjourned.

[Whereupon, at 10:40 a.m. the hearing was adjourned.]

APPENDIX

Additional Material Submitted for the Record

ALCAN PIPELINE COMPANY

JOHN G. MCMILLIAN
CHAIRMAN AND PRESIDENT

1730 PENNSYLVANIA AVENUE, N.W. • SUITE 230
WASHINGTON, D. C. 20006
(202) - 347-9400

October 28, 1977

The Honorable Henry M. Jackson
Chairman
Committee on Energy and Natural Resources
United States Senate
137 Russell Office Building
Washington, D. C. 20510

Dear Senator Jackson:

This letter is in response to the findings of Dr. Tom Woods and Mr. Bob Finney, the two GAO staff members who assisted your staff in the review of the studies available to the public on the Prudhoe Bay production potential. These findings were attached to your memorandum dated October 24, 1977, to the members of the Committee on Energy and Natural Resources concerning the October 25 hearing on the President's recommendation to designate the Alcan Pipeline Project for approval.

This response is submitted in order to put in better perspective the conclusions which were made by these two gentlemen with respect to the field simulation studies of Gruy Associates for the Interior Department, Van Poolen and Associates for the State of Alaska and Core Laboratories for the Alcan Project. For your convenience we are setting forth each conclusion followed by our comment thereon. The information contained in our comments was provided by Core Laboratories.

FINDINGS

1. We cannot evaluate Operators and D & M due to a paucity of information contained in the reports.

2. While we cannot describe the Operators and the D & M field simulations, we would conclude that of those we could, Gruy, Core and Van Poolen essentially simulate the operations of different fields although all three claim to utilize Van Poolen data. We find these anomalies in the following areas.

COMMENT - Item 2

The three subject studies did, of course, simulate the same Sadlerochit reservoir in Prudhoe Bay field. The variations in in-place hydrocarbons were slight and well within the range of accuracy to be expected from minimal adjustments of basic data and slight variations in the formulation of the three different reservoir simulators. Such variations are to be expected when three competent engineers model or simulate the same reservoir using their own professional judgment. The following figures from Van Poolen and Core Laboratories show substantial agreement:

	Gas Cap Tcf	OOIP BSTB	Sol. Gas Tcf	Total Gas Tcf
Van Poolen	26.6	19.1	13.5	40.1
Core Laboratories	26.6	19.5	15.3	41.9

Note: OOIP - Original Oil-in-Place
BSTB - Billion Stock Tank Barrels (at standard conditions)
Tcf - Trillion Cubic Feet (at standard conditions)

2a. The water drives in all three simulations are significantly different with the Van Poolen simulation having the weakest aquifer and Gruy the strongest.

COMMENT - Item 2a

Although the computed water influx may vary somewhat in the three studies (again the result of independent professional judgment), the important resulting fact is that all three studies indicate minimal water influx and a need for water injection.

2b. Both Gruy and Core only describe the Sadlerochit field and exclude considerations of hydrocarbons located elsewhere. Van Poolen posits a link between the gas cap in the Shublik formation.

COMMENT - Item 2b

The Sadlerochit reservoir is the overwhelmingly important hydrocarbon-bearing reservoir and thus is the focus of the studies. At this time the other reservoirs are relatively insignificant and are considered to be of only possible additional support. Van Poolen stated that there is a strong possibility that the Shublik reservoir may be a contributing factor but was not positive. In any event it would only be a minor plus factor.

> 2c. Core indicates that for the same field parameters, the existence of an aquifer increases oil recoverability; Van Poolen indicates the opposite, although the effect is small.

COMMENT - Item 2c

The effect of the aquifer is to increase the oil recovery but the increase is small due to minimal water influx. The apparent variation in Van Poolen's work could have been caused by variations in the assumptions made in his reservoir model. Van Poolen's program determined a need for remedial work to optimize well performance only at infrequent intervals. Core's analysis made the same determination at regular monthly intervals. As a result, Core's computed responses were more frequent and is the likely explanation for the noted variation. While the differences appear to be from positive to negative, the actual differences in recoveries between the no aquifer and with aquifer cases are small.

> 2d. The production profiles on a yearly basis with and without aquifers are significantly different for Van Poolen and Core.

COMMENT - Item 2d

Although the production profiles are different, the overall oil recoveries are similar. The variations in profiles were caused by different frequencies of monitoring the need for well workovers as explained in 2c above. Core Lab was automatic on a 30-day frequency; Van Poolen's was done manually on a much longer frequency.

2e. Similarly oil production profiles with gas sales show that the Sadlerochit field as simulated by Van Poolen does not agree with that as simulated by Core.

COMMENT - Item 2e

See Comment to Item 2d.

2f. We have found the estimates of oil-in-place and gas-in-place to be inconsistent among the studies and in the case of the operator study, internally inconsistent.

COMMENT - Item 2f

See Comment to Item 2d.

2g. We find no consistency, however, between the studies and the published API reserve figures as of 31 December 1976.

COMMENT - Item 2g

The three subject studies have the benefit of data acquired subsequent to the API study and presumably therefore merit greater credibility.

3. Despite these differences all five studies indicate either a maximum oil recovery of about 8.4 million barrels or 42.8 percent recovery of oil-in-place.

COMMENT - Item 3

The hydrocarbons initially in place and reservoir energies from water influx did not vary significantly to change the end-point findings of the studies. Variations in the profiles were caused by variations in the well workover frequencies, which did not affect the end-point recoveries.

4. Production of gas from Sadlerochit requires gas cap production early on in the productive life. At 2.4 bcf a day, the capacity of the Alcan pipeline, this would require production of oil significantly above the current 1.2 million barrel a day capacity of the TAPS to avoid excessive gas cap production.

COMMENT - Item 4

To produce 2.4 Bcf/d of gas from the Sadlerochit reservoir with no direct gas-cap gas production would, indeed, require increased oil zone production above the 1.2 million bbl./d assumed in the studies. However, because of gas injection prior to the time gas sales are commenced, no gas-cap gas need be produced to supply the 2.4 Bcf for at least 7-8 years following the commencement of sales at such volume. The term "excessive gas-cap production" as used in the findings must be evaluated, taking into account the timing of the production and other economic factors, to arrive at the optimum operating plan and producing limits.

5. All studies agree without gas re-injection, and some type of water re-pressuring, there would be significant deterioration in the recovery of oil and gas.

COMMENT - Item 5

Based on all currently available data, water injection is desirable to maximize oil recovery, however, prudent field management can assure a similar result while selling gas at the indicated volumes by adjusting other field operating parameters based on a continuing study of the performance of the Sadlerochit reservoir.

6. We find that none of the studies addressed natural gas liquids which at 1.45 gal/Mcf of gas and 2.4 bcf per day pipeline throughput results in almost 100,000 barrels a day of n.g.l.

COMMENT - Item 6

The condensate yield of 1.445 gal./Mcf of gas pertains to the gas-cap gas. The shrinkage of the gas for extraction of these liquids was taken into account. The inclusion of the liquids was not considered to be significant in reporting the various operating schemes since the liquid recovery would have been increased for all of the gas-sales cases utilized in the reservoir models and thus not significantly affect any conclusions.

> 7. We find that the production profiles in the Van Poolen and Core studies are markedly different. (Note: The attached graph shows the amount that oil production is likely to increase or decrease in a given year with 2.0 billion cubic feet of gas sales per day for Van Poolen and 2.4 bcf/d for Core.)

COMMENT - Item 7

See Comment to Item 2d.

Very truly yours,

John G. McMillian

John G. McMillian

JGMcM/gjh

ALCAN PIPELINE COMPANY

JOHN G. MCMILLIAN
CHAIRMAN AND PRESIDENT

1730 PENNSYLVANIA AVENUE, N.W. • SUITE 230
WASHINGTON, D. C. 20006
(202) - 347-9400

October 28, 1977

The Honorable Henry M. Jackson
Chairman
Committee on Energy and Natural Resources
United States Senate
137 Russell Office Building
Washington, D. C. 20510

Dear Senator Jackson:

Mr. Monte Canfield, Jr., Director of Energy and Minerals Division of the General Accounting Office, testified before your Energy Committee on September 26, 1977, in regard to the hearings on the President's Decision and Report on an Alaskan Natural Gas Transportation System. Following his testimony, certain press reports indicated that Mr. Canfield would not be surprised if the final cost of the Alcan Pipeline Project reached \$25 or \$30 billion. This reference to \$25 or \$30 billion was a comment by Mr. Canfield in a press interview and there is no basis for such numbers in Mr. Canfield's testimony.

The Sponsors of the Alcan Project are convinced that there is no reasonable possibility that the ultimate cost of the Project could reach such figures. We believe such reports are misleading and any such estimates unfounded speculation. While Mr. Canfield's testimony did not mention an estimate of \$25 or \$30 billion, he did assert that Alcan's budget has increased from \$6.7 billion in March 1977 to a current estimate of \$9.6 billion. This statement is misleading because while the estimate of \$6.7 billion is in 1975 dollars, as Mr. Canfield acknowledged the estimate of \$9.6 billion is in escalated dollars, based upon the same base estimate, which was not indicated.

98-069 O - 78 - 28

The Administration estimate of $13.204 billion (President's Decision, p. 157, excluding the Dempster line) is in escalated dollars, includes facilities which reflect the Agreement between the U. S. and Canada, and assumes overruns similar to the Alyeska experience of about 40%. Alcan's present estimate reflecting the inter-governmental agreement is $7.4 billion in 1975 dollars excluding the cost of the Dempster line. Assuming the Administration's five percent inflation rate, the escalated cost estimate with any assumed overrun is only $9.9 billion. We point out these significant differences to emphasize the importance of carefully defining the cost estimates being used.

We do agree with Mr. Canfield that management control, development of site specific data and an ongoing audit of expenditures are important for a successful project. We are instituting such procedures and have always urged governmental involvement in the project planning at the earliest possible time. The government's role is equally important to minimize delay and avoid unexpected design and construction changes. With proper planning and coordination, we believe the project can be placed in operation without unreasonable cost overruns for the following reasons:

The cost estimate for the Alaskan segment of the Alcan Project is much more complete than was the original Alyeska estimate and in fact is based upon actual experience from the Alyeska project for the Alaska segment. The Canadian and Lower 48 segments which represent two-thirds of the total project cost are much less subject to overrun since the construction is performed under more normal climatic and economic conditions. Further, all of the estimates have been subjected to the crucible of the hearing process resulting in refined and well supported estimates.

We request that this letter in response to Mr. Canfield's statements be placed in the record of the proceedings.

Very truly yours,

John G. McMillian

John G. McMillian

JGMcM/gjh

Promotes the Conservation, Development and Wise Utilization of the Fisheries

American Fisheries Society
ORGANIZED 1870 | INCORPORATED 1910

ARTHUR N. WHITNEY
PRESIDENT 1977-1978

CARL R. SULLIVAN
EXECUTIVE DIRECTOR

ROBERT L. KENDALL
EDITOR
TEL. (301) 596-3450

October 5, 1977

OCT 6 1977

Senator Henry M. Jackson, Chairman
Senate Committee on Energy and Natural Resources
3106 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Jackson:

The American Fisheries Society wishes to submit the following testimony concerning the Alaska Natural Gas Transportation System issue and we ask that our position be made a part of the official record of hearing.

The American Fisheries Society is an organization of professional fisheries scientists whose common goal is to promote research conservation, development, and wise utilization of fisheries, both recreational and commercial. Having been organized well over a century ago, we are the oldest and largest organization of fisheries scientists in the world. Our members are active in fisheries research, education, and management throughout the United States and Canada and are particularly active in Alaska.

The American Fisheries Society supports the President's recommendation of the Alcan gas line routing. We do, however, have special concern for the environmental implications of the project.

Many members of our Alaska Chapter worked in close association with the recently completed Alaska oil pipeline project. They have a deep interest and strong expertise in pipeline related environmental problems which should be utilized in the pending gas line project.

To minimize damage to aquatic resources and to reduce excessive cost and schedule delay, responsible pipeline construction companies begin working closely with resource agencies in the project preliminary planning stage.

Alcan has indicated their desire to cooperate closely with all responsible Alaska resource agencies with that cooperation to begin at the earliest stage of the project. The company has in fact indicated the need to initiate this close coordination as early as January 1, 1978, with a review of existing data and work in the field to establish the preliminary pipeline alignment.

5410 GROSVENOR LANE • BETHESDA, MARYLAND 20014 • (301) 897-8616

Input by Alaskan resource agencies on the TAPS oil pipeline was not fully instigated until the company's final design stage. Changes to avoid critical habitat areas were costly and time consuming and thus - nearly impossible.

Most responsive resource agencies believe that maximum protection to resources can only be accomplished by working with the company at the earliest stages to identify sensitive areas which, if not identified, may require costly changes of design and alignment.

If there is to be an early, coordinated review and planning effort - there is great urgency for formation of a State/Federal interagency, interdisciplinary early planning resource team. This group should be formed immediately and should coordinate work on the issues as follows:

1. Review the proposed alighment, plans and design;

2. Develop and implement studies needed for the review of permits and for the company to develop final designs and alignment;

3. Determine necessary stipulation changes from the existing TAPS stipulations (considered by Alaskan resource agencies to be adequate in most instances) to be applied to the gasline project;

4. Organize the formal governmental team which would review the final plans, designs, alignment and permits and which would carry out the surveillance and enforcemnt of stipulations and permits during civil and mainline construction and during the operation and maintenance phases.

There are other issues of importance to assure minimal impact to aquatic resources within Alaska, Canada, and the contiguous United States.

Our major concern is the structure, coordination and level of biological input in the governmental review, surveillance and enforcement effort during the construction and maintenance phases.

The Joint State/Federal Fish and Wildlife Advisory Team (JFWAT) on the TAPS oil pipeline project was formed by Congressional decision with the purpose of protecting fish and wildlife resources during construction of that project. It has been indicated that environmental damage was not minimized on that project to the extent possible because of lack of stipulation compliance by the company and the lack of governmental enforcement of the stipulation. The biologists, in an ADVISORY capacity only, could not provide the protection directed by Congress.

Last May, three JFWAT biologists were elevated to the position of Field Representatives with the authority to enforce the stipulations and thus to correct some long-standing fish passage and erosion control problems.

There should be interdisciplinary coordination within the review and surveillance efforts of the gasline project. From an environmental protection standpoint - it is necessary that both engineers and biologists are at an equal level - both in the field of enforcement effort and throughout in the entire organizational structure.

An international biological resource team is needed to coordinate and to ensure consistent environmental protection to aquatic resources along the entire 4,782 mile project. Economically and environmentally, much can be saved if experienced biologists can review concepts learned on the TAPS project and implement them to related activities in their regions. AFS member biologists in Alaska, Canada, and the ten affected contiguous states, foresee the need to form an international team immediately to minimize duplication of effort and studies and to avoid recurrent failures to protect resources to the degree possible.

The American Fisheries Society requests that Congress include means to implement the above concepts in their final decision.

Thank you for the opportunity to comment. If we can be of any service please call upon us.

Sincerely,

Carl R. Sullivan

Carl R. Sullivan
Executive Director

CRS/rr

BUD TIMS
CHAIRMAN
ERNEST GARFIELD
COMMISSIONER
JIM WEEKS
COMMISSIONER

DONALD E. VANCE
EXECUTIVE SECRETARY

ARIZONA CORPORATION COMMISSION
2222 WEST ENCANTO BLVD.
PHOENIX, ARIZONA 85009

October 25, 1977

The Honorable Henry M. Jackson
United States Senator
Chairman, U. S. Senate Energy and
Resources Committee
Washington, D. C. 20510

Dear Senator Jackson:

The Arizona Corporation Commission is well aware that unless natural gas supplies to the state can meet growing consumer demands, all Arizonans will feel a severe economic impact.

You have the opportunity at this time to assure that new supplies can be made available to all Arizonans.

As you consider the many important proposals regarding the Alaska Natural Gas Transportation System, it is vital that marketing recommendations be made with one consideration outweighing all others. That is, Arizona and all parts of the country must have access to a fair share of the gas reserves from Prudhoe Bay. We urge you to adopt a marketing plan that will accomplish this goal. It is in Arizona's interest -- it is in the nation's interest that you do so.

Arizona is totally dependent on outside sources for its natural gas. The Corporation Commission and the state's gas retailers - the utilities that sell gas energy to consumer - have been wrestling with limited supplies and growing gas demands for years. Moratoriums on new gas hookups, curtailments, and constant apprehensions about the state's dwindling gas supplies from out-of-state distributors have been a major concern of the Arizona Corporation Commission for years. These concerns have been voiced again and again.

For example, Arizona intervenors presented evidence of ourgas supply deficiencies in the Federal Power Commission proceedings related to bringing gas from Alaska to the lower 48 states.

...

SOUTHERN ARIZONA OFFICE: 415 W. CONGRESS STREET — TUCSON, ARIZONA 85701

Our governor expressed his concerns in this regard, in a letter to President Carter earlier this year.

The Arizona Corporation Commission has been advised that curtailments borne for the past few years by industry will soon spread to commercial establishments - perhaps even to residences in the decade ahead. We've been advised that the state will need an additional 100,000 Mcf of gas per day to meet our highest priority customer requirements.

We urge you to expedite the movement of the Prudhoe Bay natural gas to Arizona consumers.

And we urge you to specify that the Alaskan gas be sold to interested local distributors in proportion to their contract volumes with interstate pipeline distributors.

This will insure that the recommendations made by the Federal Power Commission, and supported by the President, regarding broad distribution of the gas can become a first step toward positive legislation that considers the energy needs of all consumers.

Sincerely,

BUD TIMS, CHAIRMAN

ERNEST GARFIELD, COMMISSIONER

JIM WEEKS, COMMISSIONER

BT:eh

ARIZONA PUBLIC SERVICE COMPANY

P. O. BOX 21666 · PHOENIX, ARIZONA 85036

KEITH TURLEY
PRESIDENT AND
CHIEF EXECUTIVE OFFICER

October 24, 1977

The Honorable Henry M Jackson
Chairman
Energy and Natural Resources
3106 Dirksen Senate Office Building
Washington, D C 20510

Dear Senator Jackson:

Nearly 340,000 natural gas customers depend on Arizona Public Service Company and its sole supplier of natural gas to provide this vital energy source for their homes, businesses, schools and shops.

The uncommitted supply of natural gas from the North Slope of Alaska -- the Prudhoe Bay reserves -- must be made accessible to Arizona consumers and to all consumers in the nation. This must be done to protect our consumers' energy future.

It must be done to protect their economic future.

It must be done in the national interest.

Please allow me to provide a brief review of the critical natural gas situation in Arizona, where Arizona Public Service Company is the state's largest gas retailer.

Faced with a dwindling supply of natural gas from our supplier, Arizona Public Service Company sought a moratorium from the Arizona Corporation Commission on new gas connections four years ago. Following clarification of an order from the Federal Power Commission, the Corporation Commission agreed that the company should make no new gas connections after December 31, 1976. The moratorium affects all new gas hookups in Arizona Public Service Company's gas service territory that spans nearly 30,000 miles in Arizona. It includes the so-called "priority one" residential customers.

During the 1976-77 heating season, our industrial customers were curtailed for more than 90 days. Some time in the 1980s, we anticipate these curtailments will be necessary for commercial, and even for residential customers.

As you are well aware, Arizona's population is growing at the fastest rate in the nation. These increases in population are contrasted with a continuing decline in natural gas supplies.

We urgently need access to a fair share of the Alaska North Slope natural gas to serve our Arizona consumers.

Arizona Public Service Company presented evidence of our gas supply deficiencies in Federal Power Commission proceedings related to bringing this gas from Alaska to the lower 48 states.

It has been estimated that the state will require some 100,000 Mcf of natural gas each day to meet our highest priority customers' needs; the uncommitted Alaskan supply will help alleviate this deficiency.

Already, as a result of recommendations of the Federal Power Commission to the President, the theory for wide distribution of Alaskan gas has been spelled out. As you know, this decision freed these gas reserves from advance payment arrangements between producers and large pipeline distributors in the 48 contiguous United States. I support this recommendation by the FPC and President Carter's statement urging this course of action.

In order to be meaningful, however, I firmly believe additional information about access to the gas reserves must be spelled out. It must be made specific so that broad distribution across domestic markets is guaranteed.

How can this best be done? I strongly urge that, rather than leaving gas allocations to private contract negotiations between the producers and would-be purchasers, you specify that the gas be sold in proportion to interested local distributors' contract volumes with their interstate pipeline suppliers.

I urge you to establish marketing guidelines that will insure this is accomplished.

Furthermore, I urge you to take steps so that consumers will not be forced to pay the price of noncompletion of the Alaskan transportation project or to pay for gas they do not receive.

These are the fairest and most equitable bases for proposals to insure that consumers in Arizona -- and consumers in other areas -- will not have to endure the economic hardships that will surely result if all areas of the country are not given equal consideration regarding the marketing of the Alaska natural gas.

Very truly yours,

KT:mb

October 25, 1977

Dr. Howard A. Koch, Manager
Engineering Department
North American Producing Division
Atlantic Richfield Company
Dallas, Texas

Dear Dr. Koch:

At the Energy and Natural Resources Committee hearing this morning on the Alcan Pipeline proposal questions to be answered in writing were submitted for the Record. I would appreciate your response to the following:

1. Could you describe what is presently being done with the natural gas liquids from Prudhoe Bay?

2. Will you allow an independent petroleum engineer to review your simulated computer runs? To complete new ones?

3. Have you completed any studies of the feasibility of gas reinjection and early implementatinn of a water flood?

Would you provide the Committee with these studies?

4. The existence of low residual saturation to gas invasion appears to be a pre-requisite for successful implementation of the proposed operating plan. Yet studies sponsored by the operators apparently contradict the existence of this condition.

In the fact of your studies, how do you justify existence of these necessary conditions?

5. The operator's plan relies heavily on the assumption that there is low residual oil saturations in the Saddlerochit. Yet the operators are planning a small scale test of water injection to get information on the actual residual oil saturation to water encroachment. Why

is such a test necessary? If such a test disproves your assumption, and if gas reinjection is necessary tommaintain pressure, what can you do to assure no loss of oil?

6. High vertical permeability is apparently another pre-requisite for success of the proposed operating plan. Have you used a standard published techmique for measuring in-site vertical permeability in the vicinity of a well? Why not?

7. How much oil will be left behind in the reservoir at the completion of production under the present production plan?

What are your plans for getting this oil out through tertiary recovery?

8. How can you justify such a firm conclusion on production of 2 bcf/day of gas when you can't reach a conclusoon on when to begin water injection?

Because of the time constraints, I trust you will submit your answers in writing to the Committee as soon as possible and certainly no later than Monday, October 31, 1977.

Thank you for your consideration.

Sincerely,

John A. Durkin

JAD/cbw

AtlanticRichfieldCompany 1025 Connecticut Avenue, N.W.
Washington, D.C. 20036
Telephone 202 457 6219

William E. Duke
Director
Federal Governmental Affairs

October 31, 1977

Honorable John A. Durkin
Senate Energy and Natural
Resources Committee
1409 Dirksen Senate Office Building
Washington, D. C. 20510

Dear Senator Durkin:

By letter dated October 25, 1977, you requested that we respond to a series of questions which arose during the course of the Alcan Pipeline hearing. Set forth below is Atlantic Richfield's response:

Question: 1. Could you describe what is presently being done with the natural gas liquids from Prudhoe Bay?

Answer: At this time, only a small quantity of NGLs is being removed from the Prudhoe Bay gas via the field fuel unit. These liquids are reinjected into the field with the bulk of the produced gas.

Question: 2. Will you allow an independent petroleum engineer to review your simulated computer runs? To complete new ones?

Answer: As we indicated to the Senate Energy and Natural Resources Committee in our comments upon the GAO observations, we would be pleased to discuss our simulator results with a GAO representative. He would, of course, be free to make any independent studies he wished.

Question: 3. Have you completed any studies of the feasibility of gas reinjection and early implementation of a waterflood? Would you provide the Committee with these studies?

Answer: We are currently reinjecting into the field most of the gas produced at Prudhoe Bay. Other gas is used as field fuel or for sale to TAPS owners for pipeline fuel. As pointed out in Dr. Howard Koch's testimony before the Committee, we have studied cases of gas reinjection for periods of 5 to 15 years. We have also studied water injection commencing after both 5 and 7 years of oil production. In our more recent model descriptions, water injection after 5 years of production was the earliest injection considered, since it would not be possible to commence such an injection program much sooner. We will be pleased to discuss the results of these cases with the Committee.

Question: 4. The existence of low residual saturation to gas invasion appears to be a pre-requisite for successful implementation of the proposed operating plan. Yet studies sponsored by the operators apparently contradict the existence of this condition. In the face of your studies, how do you justify existence of these necessary conditions?

Question: 5. The operator's plan relies heavily on the assumption that there is low residual oil saturations in the Sadlerochit. Yet the operators are planning a small scale test of water injection to get information on the actual residual oil saturation to water encroachment. Why is such a test necessary? If such a test disproves your assumption, and if gas reinjection is necessary to maintain pressure, what can you do to assure no loss of oil?

Answer: 4. and 5. Our operating plan does not depend on the residual oil saturations left behind the invading gas cap. If this residual oil saturation is larger than we currently anticipate (20-30%) it would mean that the gas cap would merely expand further into the oil column, since total gas cap expansion is dependent upon total oil zone voidage. As Dr. Koch pointed out in his detailed testimony (page 8), this would result in a decline in oil rate quicker than we anticipate, if nothing were done to offset the rapid gas/oil contact advance. Under these same circumstances, lower ultimate oil recoveries could also result, with or without gas sales; however, it should be assumed that the operators will adjust the operating plan to assure efficient recovery. If we foresee the occurrence of this situation, a number of modifications in our plan can be made:

1. The well density could be increased to allow more oil to be produced at lower gas-oil ratios.

2. Additional gas handling facilities could be added.

3. A source waterflood to help retard the gas/oil contact advance could be initiated.

Therefore, the success of early gas sales, is not dependent upon the residual oil saturations left behind the invading gas cap. This residual oil saturation, however, will give us an indication as to the proper timing of a source waterflood. The benefits of source waterflooding are dependent upon the residual oil saturations left behind an invading water front. Although our current estimates of residual oil saturation to water lead us to believe that a source waterflood will be economically successful, we recognize the desirability for in-situ measurements. Therefore, in our water injection test, we will endeavor to obtain such measurements. Collection of actual field performance data gathered concurrently with this injectivity testing will allow us to select the best locations for water injection wells as well as the appropriate local volumes so that we may efficiently supplement the available drive mechanisms.

Our estimate of ultimate recovery anticipates the success of a source water injection program. In the unlikely event that our water injection tests prove that such a program is not as efficient as we currently estimate, other methods to increase recovery will be considered.

Question: 6. High vertical permeability is apparently another pre-requisite for success of the proposed operating plan. Have you used a standard published technique for measuring in-site vertical permeability in the vicinity of a well? Why not?

Answer: We assume that the question refers to the method proposed by W. A. Burns in the June 1969 issue of the Journal of Petroleum Technology.

Two such vertical permeability tests were conducted on the A.R.Co. operated side of the field in 1970; however, the tests did not yield meaningful results.

Question: 7. How much oil will be left behind in the reservoir at the completion of production under the present production plan? What are your plans for getting this oil out through tertiary recovery?

Answer: The current operating plan anticipates that approximately 12.8 billion barrels of crude oil will be left in the main Sadlerochit reservoir at approximately 40% recovery. This is not an unusual circumstance to the U.S. oil industry. In comparison, approximately 300 billion barrels will be left in place in all other known reservoirs in the U.S. under current technology. It is this unfortunate fact that has lead oil industry research into the development of other enhanced recovery techniques.

To date, tertiary recovery processes have not been shown to be feasible for the Sadlerochit reservoir. As Dr. Koch pointed out in his detailed testimony (page 14), our research department has studied the possibility of a carbon dioxide injection process; but because our only known source of CO_2 on the North Slope is that within the Sadlerochit gas, this volume would be sufficient to flood only a small portion of the reservoir. Other tertiary recovery techniques will be examined to determine whether they can be economically used on the North Slope.

Question: 8. How can you justify such a firm conclusion on production of 2 bcf/day of gas when you can't reach a conclusion on when to begin water injection?

Answer: The impact of gas sales timing on oil recovery is determined from fluid property and in-place volume considerations. We believe that we know these values to a high degree of accuracy, and feel that our model predictions are conlusive as to the impact of early gas sales. The study of source water injection is more complex since it is highly dependent upon the multiphase flow of oil and water through reservoir rock. In order to assure maximum economic recovery through such an injection program, it will be helpful to substantiate our estimates of the amount of residual oil behind an invading water front as well as to determine the optimum volume and locations for this injection.

Hope this has been of assistance to you.

Sincerely,

QUESTIONS CONCERNING THE PRUDHOE BAY RESERVOIR

(1) Will the produced gas available for sale by solution gas or gas cap gas?
(2) Will the production from the gas cap or solution gas significantly lower the reservoir pressure?
(3) Is a water drive occurring?
(4) Is a partial water drive occurring?
(5) If a partial water drive is occurring and the reservoir pressure is declining, what are the plans for pressure maintenance?
(6) Would declining gas cap pressure create a situation that would cause oil to be lost in the gas cap portion?
(7) Would partial water drives through a faulting system as described for the Sadlerochit reservoir bypass a considerable amount of oil if pressure depletion methods were applied too rapidly?
(8) Would gas production without re-injection cause a premature oil decline?
(9) How were the maximum production rates for oil producers determined?
(10) Does the water production indicate that a natural water drive is occurring?
(11) What cost benefits would occur from a natural water drive mechanism as opposed to the installation of a secondary recovery system?
(12) Would following normal recommended engineering practices dictate that a pressure maintenance system not be designed or installed until sufficient production and pressure history data has indicated which water drive mechanism is occurring?
(13) Would gas cap withdrawals be contrary to normal engineering practices?
(14) What is the reservoir practices in the Cook Inlet oil field area? Are reservoirs in that area similar to the Prudhoe Bay reservoirs?
(15) What was the total estimated oil production from the Sadlerochit reservoir upon which you based your proposed tariffs to the ICC?
(16) Can the estimated 400 million barrels of natural gas liquids to be produced from Prudhoe Bay be transported to markets via the Alyeska oil pipeline?
(17) If a water flood using water from outside sources is not inaugurated, because it is not deemed to be economically viable, can the initial 2.0 bcfd rate be sustained for the life of the field?

AtlanticRichfieldCompany 1025 Connecticut Avenue, N.W.
Washington, D.C. 20036
Telephone 202 457 6219

William E. Duke
Director
Federal Governmental Affairs

October 31, 1977

Honorable Henry M. Jackson
Chairman
Committee on Energy and Natural
 Resources
United States Senate
1307 Russell Senate Office Building
Washington, D. C. 20510

Dear Mr. Chairman:

On October 26, 1977, you forwarded to Atlantic Richfield a series of questions that had arisen before the Senate Energy and Natural Resources Committee in its consideration of the Alcan Pipeline proposal. Set forth below is Atlantic Richfield's response to the questions:

Question: 1. Will the produced gas available for sale be solution gas or gas cap gas?

Answer: Both solution gas and gas cap gas will be produced through the Prudhoe Bay oil wells. Proven gas reserves in the Prudhoe Bay field consist of approximately 8.7 trillion cubic feet of solution gas and 17.3 trillion cubic feet of gas cap gas. We have used a special model in which the identity of the two gases were retained throughout the run. With the use of this model we were able to predict what portion of the total gas stream was made up of gas cap gas and what portion was made up of solution gas. Our work has indicated that if gas sales commence in 1983, only a portion of the gas sold in the early years will be gas cap gas. As time progresses, the percentage of gas cap gas in the sales stream will increase.

Question: 2. Will the production from the gas cap or solution gas significantly lower the reservoir pressure?

Answer: In our opinion, no. After 30 years of production the difference in reservoir pressure between a 1982 sales case and a 1992 sales case was only 115 psi.

Question: 3. Is a water drive occurring?

Question: 4. Is a partial water drive occurring?

Question: 5. If a partial water drive is occurring and the reservoir pressure is declining, what are the plans for pressure maintenance?

Answer: 3-5. We believe that a partial water drive will be present. To date, an insufficient amount of production history has been accumulated to substantiate our estimates of aquifer strength.

Reservoir pressure decline is normal in oil field operations. In fact, it is unusual to completely maintain reservoir pressure. Early pressure maintenance with large volumes of water from an outside source in a reservoir such as the Sadlerochit (with an initial gas cap in combination with a low dip angle) could result in oil being displaced into the original gas cap, thereby reducing the possibility of recovering this oil.

As pointed out in Dr. Koch's testimony (p. 7) our plans are to initiate a waterflood by 1981 utilizing produced water. In doing so, we will maximize the benefits of the natural water influx through redistribution of this water to the portions of the reservoir exhibiting low natural depletion recovery.

We currently estimate that flooding using water from an outside source will be economically viable. However, we believe that the optimum locations and volumes of this injection can best be determined after observing production performance during the early years, especially in localized areas of the field.

Question: 6. Would declining gas cap pressure create a situation that would cause oil to be lost in the gas cap portion?

Answer: No, not under the existing plan of operation. As pointed out in Dr. Koch's testimony (Page 9):

> "We do not anticipate any oil migration into the original gas cap as a result of gas cap shrinkage because of the substantial voidage accumulated by the oil rim prior to gas sales, and because of the smaller cap voidage rate in the early years of gas sales."

Question: 7. Would partial water drives through a faulting system as described for the Sadlerochit reservoir bypass a considerable amount of oil if pressure depletion methods were applied too rapidly?

Answer: No, not under the existing operating plan.

Question: 8. Would gas production without re-injection cause a premature oil decline?

Answer: We do not believe that gas production without reinjection of gas will cause a premature oil decline. As Dr. Koch testified (Page 8):

> "The advance of the gas-oil contact, to a large degree, controls the onset of oil production decline. Since the expansion of the gas cap is largely a function of oil zone withdrawals, we have seen in our models that the timing of anticipated gas sales has little or no impact on the point of oil decline."

Question: 9. How were the maximum production rates for oil producers determined?

Answer: We determined production rates by simultaneous solution of Darcy's law for radial flow of fluids through a porous media and hydraulic calculations of two-phase flow in vertical or inclined tubing strings. In some cases, well rates will have to be limited below this level due to the extraneous production of gas or water through coning. These maximum rates were determine through the use of individual well models. Initial completion intervals were selected to minimize the coning problems.

Question: 10. Does the water production indicate that a natural water drive is occurring?

Answer: No, not at this time. With cumulative oil production only amounting to about 0.2% of the original oil in place to date, it is too early to confirm our estimates of aquifer strength.

Question: 11. What cost benefits would occur from a natural water drive mechanism as opposed to the installation of a secondary recovery system?

Answer: A strong natural water drive could eliminate the need to inject source water at a system cost in excess of $1 billion.

Question: 12. Would following normal recommended engineering practices dictate that a pressure maintenance system not be designed or installed until sufficient production and pressure history data has indicated which water drive mechanism is occurring?

Answer: It is unusual to initiate a secondary recovery program early in the life of a field. If sufficient production history is not available, it is very difficult to determine areal performance anomalies and optimum locations of injection wells and volumes for water injection.

Question: 13. Would gas cap withdrawals be contrary to normal engineering practices?

Answer: This is a difficult question on which to generalize. Dr. Koch's testimony on pages 12 and 13 spoke directly to this question:

> "Potential reduction in oil recovery from any reservoir due to the early sale of gas has been a subject of considerable discussions in the field of petroleum reservoir engineering. There is <u>one</u> general conclusion that can be drawn concerning this early gas sale: i.e., the withdrawal of associated gas can cause a reduction in oil recovery if nothing is done to replace the energy. Beyond that, however, no other conclusions should be drawn. This potential reduction can only be estimated through a thorough

analysis of the drive mechanisms that are present in a particular reservoir.

One excellent method in accomplishing this is through the use of mathematical reservoir models.

In our analysis, the effect of gas sales at Prudhoe Bay was small for the following reasons:

1. The dominant recovery mechanism is gravity drainage. Gas in such a drive mechanism does not act as an expulsive force to drive the oil out of the pore spaces. Instead, the gas merely expands to fill the empty pore spaces as the oil drains out.

2. Prudhoe Bay crude is both a low shrinkage and relatively low viscosity oil.

3. Even with the earliest anticipated gas sales date (1983) approximately 30% of the ultimate oil reserves will have been recovered.

4. The normal dangers of gas cap shrinkage will not be a problem at Prudhoe Bay, due to the expansion of the gas cap in the early years of production combined with a rather modest cap voidate rate immediately after sales commence."

Question: 14. What is the reservoir practice in the Cook Inlet oil field area? Are reservoirs in that area similar to the Prudhoe Bay reservoirs?

Answer: The fields in the Cook Inlet area of Alaska have almost nothing in common with the Prudhoe Bay Field. The major difference these fields have, as far as reservoir management is concerned, is the fact that they are highly undersaturated (no initial gas cap). As a result, pressure decline during the early years of production is substantial in the absence of a gas cap to provide pressure support. Waterflooding in the Cook Inlet fields is very successful in the maintenance of reservoir pressure.

Question: 15. What was the total estimated oil production from the Sadlerochit reservoir upon which you based your proposed tariffs to the ICC?

Answer: In its application for a pipeline tariff, Arco Pipeline Company, an Atlantic Richfield affiliate, submitted to the Interstate Commerce Commission the following throughput rates for the TAPS piepline:

		Barrels Per Day
1977	Sept-Oct	.6MM
	Nov-Dec.	1.2MM
1978		1.2MM
1979		1.2MM
1980	1st Half	1.2MM
	2nd Half	1.6MM
1981		1.6MM

Question: 16. Can the estimated 400 million barrels of natural gas liquids to be produced from Prudhoe Bay be transported to markets via the Alyeska oil pipeline?

Answer: The quantity of the RGLs available for shipment through the crude oil line is dependent upon gas pipeline specification. The NGLs remaining after field fuel usage can be shipped through TAPS if appropriate sub-cooling of the crude oil is accomplished and if gas sales are not unreasonably delayed.

Question: 17. If a waterflood using water from outside sources is not inaugurated, because it is not deemed to be economically viable, can the initial 2.0 bcfd rate be sustained for the life of the field?

Answer: In his testimony (Page 16) Dr. Koch stated that gas deliveries of at least 2 BCF per day could be sustained for approximately 25 years. This statement is based upon the assumption that the State of Alaska would approve such rate. At this time, we cannot determine whether the same rate would be approved by the State without injection of some water.

I hope this material is of assistance to the Committee.

Sincerely,

WED/ekh

AtlanticRichfieldCompany 1025 Connecticut Avenue, N.W.
Washington, D.C. 20036
Telephone 202 457 6219

William E. Duke
Director
Federal Governmental Affairs

October 31, 1977

Honorable Henry M. Jackson
Chairman
Committee on Energy and Natural Resources
United States Senate
1307 Russell Senate Office Building
Washington, D.C. 20510

Dear Mr. Chairman:

On October 25, 1977, the Committee on Energy and Natural Resources requested that Atlantic Richfield respond to a series of observations made by representatives of the General Accounting Office. Set forth below are Atlantic Richfield's comments:

GAO: 1. We cannot evaluate Operators and D & M due to a paucity of information contained in the reports.

Response: Atlantic Richfield made the results of seven simulator cases available to the Division of Oil and Gas Conservation, State of Alaska in May of this year. These results are also available for inspection by designated representatives of the GAO.

GAO: 2. While we cannot describe the Operators and the D & M field simulations, we would conclude that of those we could, Gruy, Core and van Poollen essentially simulate the operations of different fields although all 3 claim to utilize van Poollen data. We find these anomalies in the following areas.

(a) The water drives in all three simulations are significantly different with the van Poollen simulation having the weakest aquifer and Gruy the strongest.

(b) Both Gruy and Core only describe the Sadlerochit field and exclude considerations of hydrocarbons located elsewhere. van Poollen posits a link between the gas cap in the Shublik formation.

(c) Core indicates that for the same field parameters, the existence of an aquifer increases oil recoverability van Poollen indicates the opposite, although the effect is small.

(d) The production profiles on a yearly basis with and without aquifers are significantly different for van Poollen and Core.

(e) Similarly, oil production profiles with gas sales show that the Sadlerochit field as simulated by van Poollen does not agree with that as simulated by Core.

Response: We have no comments on the GAO observations 2(a) - 2(e). Apparently GAO has noted differences between the studies of Gruy, Core Laboratories, and H. K. van Poollen. We would recommend that GAO discuss these differences with the appropriate consultants. As noted in our response to GAO observation No. 1, we will be pleased to discuss our production profiles with GAO representatives.

GAO: 2(f) We have found the estimates of oil-in-place and gas-in-place to be inconsistent among the studies and in the case of the operator study, internally inconsistent.

Response: The staff is apparently confusing "In-Place" and "Reserve" estimates. Clarification of reserve estimates contained in "Technical Considerations -- Prudhoe Bay Unit Operating Plan (the Plan)" would be appropriate. Figure 3 of the Plan included in-place estimates of gas cap gas in trillions of cubic feet (tcf) and oil-in-place in billions of reservoir barrels. To convert reservoir barrels to stock tank barrels and to calculate solution gas-in-place, reference should be made to page 16 of the Plan. Using these conversion constants and a recovery factor of 40% for the main area Sadlerochit reservoir one can confirm the crude oil reserves of 8.5 billion stock tank barrels as reported on page 47 of the Plan. Application of a 75% recovery factor to the total gas-in-place (cap gas as well as solution gas), allowing for shrinkage and C02 removal, results in 26 trillion cubic feet of dry hydrocarbon gas reserves, also reported on page 47 of the Plan.

GAO: 2(g) We find no consistency, however, between the studies and the published API reserve figures as of 31 December 1976.

Response: We do not believe that the results of the studies and the API reserve estimates are inconsistent. In the Plan (Exhibit A to Dr. Howard Koch's testimony) reserves of 8.5 billion barrels of crude oil are reported for the main area Sadlerochit only. The API definition of oil reserves appearing on page 13 of their May, 1977 report includes:

1. Liquids technically defined as crude oil (a mixture of hyrdocarbons that exist in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities).

2. Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators (sometimes referred to as condensate).

3. Small amounts of nonhydrocarbons produced with the oil.

Unlike the reserve estimate in the Plan, the API estimate is reported to include proven reserves of Sadlerochit crude oil and condensate, Sag River crude oil, Shublik crude oil and Eileen area crude oil.

GAO: 3. Despite these differences all 5 studies indicate either a maximum oil recovery of about 8.4 million barrels of 42.8 percent recovery of oil-in-place.

Response: Often, confusion arises when speaking of ultimate oil recovery in barrels or as a percentage of the oil-in-place. Most of the simulator cases run were for the Sadlerochit main area only. The results do not include projections for the other reservoirs in the "Prudhoe Oil Pool", or condensate reserves. Additionally, please note that the GAO observation refers to millions of barrels of oil - this should have been billions of barrels.

GAO: 4. Production of gas from Sadlerochit requires gas cap production early on in the productive life. At 2.4 bcf a day, the capacity of the Alcan pipeline, this would require production of oil significantly above the current 1.2 million barrels a day capacity of the TAPS to avoid excessive gas cap production.

Response: The Prudhoe Bay Unit owners have not recommended gas deliveries of 2.4 bcfd. In the Plan, they have recommended, and the State of Alaska, Division of Oil and Gas Conservation, has approved, deliveries of 2.0 bcfd.

The Plan as approved would not create gas cap shrinkage.

GAO: 5. All studies agree without gas reinjection, and some type of water repressuring, there would be a significant deterioration in the recovery of oil and gas.

Response: While the result described by GAO may be theoretically correct, the Plan does not contemplate operating the field in this manner. Gas will be reinjected until a gas transmission system is available. The timing of water injection will depend upon reservoir performance and further studies.

GAO: 6. We find that none of the studies addressed natural gas liquids which at 1.45 gal/mcf of gas and 2.4 bcf per day pipeline throughput results in almost 100,000 barrels a day of n.g.l.

Response: If gas sales commence in 1983, most of the natural gas liquids extracted from the gas can be transported in the TAPS line.

GAO: 7. We find that the production profiles in the van Poollen and Core studies are markedly different. (Note: The attached graph shows the amount that oil production is likely to increase or decrease in a given year with 2.0 billion cubic feet of gas sales per day for van Poollen and 2.4 bcfd for Core.)

Response: As in our response to findings 2(a) - 2(e), we believe that these differences can only be understood by contacting the appropriate consultant.

Hope this will be of assistance to you.

Sincerely,

Bill Duke

William E. Duke

October 25, 1977

Mr. E. G. Houlston, Manager
Reservoir Engineering
BP Alaska, Inc.
San Francisco, California

Dear Mr. Houlston:

At the En~~ergy and Natural Resour~~ces Committee hearing this morning on the Alcan Pipeline proposal questions to be answered in writing were submitted for the Record. I would appreciate your response to the following:

1. Could you describe what is presently being done with the natural gas liquids from Prudhoe Bay?

2. Will you allow an independent petroleum engineer to review your simulated computer runs? To complete new ones?

3. Have you completed any studies of the feasibility of gas reinjection and early implementation of a water flood?

Would you provide the Committee with these studies?

4. The existence of low residual saturation to gas invasion appears to be a pre-requisite for successful implementation of the proposed operating plan. Yet studies sponsored by the operators apparently contradict the existence of this condition.

In the face of your studies, how do you justify existence of these necessary conditions?

5. The operator's plan relies heavily on the assumption that there is low residual oil saturations in the Saddlerochit. Yet the operators are planning a small scale test of water injection to get information on the actual residual oil saturation to water encroachment.

Why is such a test necessary? If such a test disproves your assumption, and if gas reinjection is necessary to maintain pressure, what can you do to assure no
1 loss of oil?

6. High vertical permeability is apparently another pre-requisite for success of the proposed operating plan. Have you used a standard published technique for measuring in-site vertical permeability in the vicinity of a well? Why not?

7. How much oil will be left behind in the reservoir at the completion of production under the present production plan?

What are your plans for getting this oil out through tertiary recovery?

8. How can you justify such a firm conclusion on production of 2 bcf/day of gas when you can't reach a conclusion on when to begin water injection?

9. In your testimony you state the Saddlerochit contains 21.4 billion stock tank barrels. In the report submitted to the State, Technical Considerations Prudhoe Bay Unit Operating Plan North Slope Alaska, the total reserve estimate for the Saddlerochit is 27.2 billion. What is the reason for this glaring discrepancy?

10. Your statement says that your studies have shown the timing of gas sales at a rate of 2 bcf/day only slightly affects oil recovery. Yet, Van Poollen has estimated a gain of 400 million barrels from delaying gas sales four and a half years. This evidence suggests that gas sales detracts from oil recovery. Do you have proof to indicate otherwise?

Because of the time constraints, I trust you will submit your answers in writing to the Committee as soon as possible and certainly no later than Monday, October 31, 1977.

Thank you for your consideration.

Sincerely,

John A. Durkin

JAD/cbw

BP Alaska Inc. 100 Pine Street, San Francisco, California 94111. Telephone (415) 445-9400

October 28, 1977

Senator John A. Durkin
United States Senate Committee
on Energy and Natural Resources
Washington, D.C. 20510

Dear Senator Durkin:

I submit, herewith, answers to the questions you raised following the Energy and Natural Resources Committee hearing on October 25, 1977. I hope that these responses together with the testimony presented at the hearing will be helpful.

On behalf of BP Alaska Inc./Sohio, I would like to express our appreciation for the opportunity extended to us to clarify the considerations which have entered into the formulation of the operating plan for the Prudhoe Bay Field.

Sincerely,

George Houlston

George Houlston

EGH:rt

Attachment

cc: Elizabeth Moler
George Dowd

<u>Answers to questions contained in letter of 25 October, 1977 from Senator Durkin to Mr. Houlston</u>

1. Gas liquids are not being extracted from the gas that is produced in Prudhoe Bay. All gas, except that consumed as fuel, is being reinjected. The reinjected gas includes a small volume of hydrocarbon components that condense as liquid, without special processing, out of the produced gas.

2. We have presented publicly the results of our computer runs and discussed at length the assumptions and data on which these runs are based. We feel that this information is adequate for an independent party to judge the competence and thoroughness of this work. This information is on public record in Anchorage. We would be willing to provide more information from time-to-time if this is required.

   Further runs of the type we have already made are not likely to yield any additional insight into reservoir performance. Our present efforts are directed towards constructing more detailed models that are suitable for reservoir performance history matching, and subsequent extrapolation into the future. Work on such models is being actively pursued, with descriptive reservoir data that is more up-to-date.

3. A case has been run by BPA in which no gas was sold and a large volume water injection scheme was started at 4½ years after the start of production. However, since running this case, our reservoir description has been revised. Hence the results of this case are not strictly comparable to those already presented. In order to clarify this, we attach results on two cases, labelled here A and B.

Case A is the same as Case 3 presented in BPA's testimony at the Alaska State hearings in May, except that Case A was run with an older reservoir description. The oil recovery at the end of 25 years is 41.2%.

Case B is the same as A, except that no gas is sold. All gas unconsumed is reinjected. Recovery at 25 years is 41.4%. However, the oil rate at the end of the run of some 200000 b/d is about double that in Case A. This implies a further recovery for Case B of about 1%.

The effect of reinjecting gas instead of selling it, in these two cases, is almost identical to the effect shown in Cases 1 & 2 of BPA's public testimony. Cases 1 & 2 had recoveries of 32.8 and 32.9% respectively. In Cases 1 & 2 only produced water was returned to the formation.

Our conclusion from this work is that gas sales, at a rate of 2 BCF/D, do not affect oil recovery significantly. Water injection on the other hand does substantially improve recovery, whether gas is sold or not. We do not view water injection as an alternative to gas injection, and this reiterates the conclusion stated in our public testimony.

4. Low residual oil saturations in parts of the reservoir that are invaded by gas, are not a necessary condition for our operating plan. Indeed, opinions on such residual oil saturations vary. BPA does not believe the residual oil saturations will be all that low. Nevertheless, our studies lead us to full support of an operating plan that includes sale of gas, after some 25% of the oil reserves have been produced, and water injection.

   The final oil saturations in our computer runs should be distinguished from the much lower minimum end point saturations that appear in mathematical relationships as part of the input data for the calculations.

5. Water injection tests will, it is hoped, yield information on the residual oil saturation achievable with a water flood. This in turn will be helpful in planning a water flood. The water injection tests are also being carried out to obtain data on:

   i) water injectivity, which has a major bearing on how many water injection wells are needed
   ii) the nature of the heavy oil zone and its influence on natural water influx
   iii) the capability of shallower sands to supply injection water.
   iv) mechanical aspects of injection equipment to assist in the design of a field-wide injection system.

It should be pointed out that we advocate water injection to recover oil, not to maintain pressure. Part of the extra oil recovery is due to pressure maintenance, but this is a secondary effect. If it is necessary to inject water, merely to maintain pressure, water can be injected into the gas cap. At present, all our studies indicate the cap to be the place where we will get the least amount of oil per barrel of water injected.

With regard to gas injection, we would point out that with an anticipated weak water drive, the reinjection of produced gas will replace only about a third of the volumetric withdrawals from the reservoir. Hence gas reinjection by itself, will not maintain reservoir pressure.

In the unlikely event that water injection proves to be infeasible or injurious to oil recovery, then the total oil recovery will be lower than projected. We would deplore, however, the use of the term 'loss of oil' in this context, since any decrease in expected recovery can only be a loss if proven and economic methods of recovering the oil in question were not implemented.

6. Again, high vertical permeability is not a prerequisite for the operating plan. BPA has lower vertical permeabilities in its models than Exxon, and consequently calculates higher residual oil saturations under gravity drainage. Recovery by this mechanism is due to the oil trickling down by its own weight, rather than to gas, at whatever pressure, sweeping the oil out. Overall oil recoveries indicated by the separate studies from the various companies, are very similar.

We have not carried out an in-situ vertical permeability test because:

i) the techniques employed in such tests are ill-suited to Prudhoe Bay conditions,

ii) such tests are generally open to a wide range of interpretation,

iii) two tests of this type carried out by Arco yielded only qualitative information that, in retrospect, could have been inferred by other means,

iv) a test would only give information at one point in a huge heterogeneous reservoir,

v) much wider coverage on vertical permeability will be obtainable from the coning behaviour of wells.

7. Our operating plan aims to maximize the recovery of oil by proven primary and secondary recovery methods. It is estimated that application of these methods would leave 60% of the oil in the ground. Clearly, the potential for so-called tertiary recovery schemes is large.

It is not, however, the <u>plan</u> to leave 60% of the oil in the ground, but rather as little as possible. The operating plan is not a rigid set of rules to be applied over the next 40 years; nor do our computer runs include all possible future field operations. Tertiary recovery for example, has been omitted from the runs because it is difficult to simulate and an order of magnitude more uncertain in its outcome.

There is no method of tertiary recovery that has at present been shown to have a high chance of success if applied in Prudhoe Bay. CO_2 injection is of limited applicability because of the oil composition, but should not be ruled out. Tertiary recovery in Prudhoe Bay is worthy of long-term study, but any definite plan for tertiary recovery would be premature with the present state of knowledge of the reservoir.

8. The effect of gas sales on the reservoir is chiefly one of pressure. This pressure effect is readily calculated. The performance of water injection, however, depends on fluid displacement mechanisms, and is therefore subject to greater uncertainty. Hence conclusions on gas sales are firmer than those on water injection.

Nevertheless, BPA have concluded that water injection should begin as soon as is practicable. Design and construction of a water distribution and injection system to operate under Arctic conditions, will however, take several years. Resources in terms of energy and materials that will be expended in the project will be large. It is therefore important that these resources be deployed so as to give the greatest return in oil recovery. In order to achieve this, some reservoir performance is necessary. Although BPA's view of the oil recovery to be obtained from gravity drainage in Prudhoe Bay is relatively pessimistic compared to the views of other companies, gravity drainage potentially can give a higher recovery than water drive. Prudhoe Bay is a large field and there may be areas of efficient gravity drainage within it. We would not wish to pass up the chance of a high recovery by blocking a good gravity drainage with water. Different water injection schemes are likely to be suitable in different parts of the field. The information gathered during the first two or three years of production will result in a water flood that is closer to the optimum for the field.

9. The figure of 27.2 billion barrels is not a reserve estimate, nor does it refer to the total Sadlerochit. 27.2 billion barrels is the volume in-place of light oil only, in the main area of the reservoir only, and at reservoir conditions.

The total Sadlerochit oil, both light and heavy, in the main area is 29.1 billion barrels at reservoir conditions. If a barrel of oil is brought to the surface, its volume shrinks, due to gas coming out of solution. Under Prudhoe Bay conditions a barrel of oil at the surface would occupy about 1.36 barrels at subsurface conditions (due to dissolved gas). Therefore, the 29.1 billion barrels would shrink to 21.4 billion barrels when expressed at surface conditions; i.e., stock tank barrels of oil with gas removed. This is still not a reserve figure since it is not possible to bring all the oil to the surface.

In reservoir simulation computer runs the percentage recovery is more significant than oil recovered, since for comparative purposes runs were made with pre-1976 in-place figures.

10. We are unable to find a case among van Poollen's runs, in which gas sales have been delayed 4½ years. However, in Case 25 gas sales have been delayed 4 years, relative to Case 20. The improvement in recovery due to delayed gas sales is 500 million barrels. The reason for this comparatively large difference is that in Case 20 gas sales were started very early, that is at 2-3/4 years. None of our runs have

assumed such early gas sales. Moreover, Cases 20 and 25 have been run at 1.2 MMB/D oil offtake, whereas we have generally used 1.5 MMB/D. Our calculated effect of the delay in gas sales is small, because we have not started gas sales, even at the earliest, until a larger fraction, some 25%, of the oil reserves have already been recovered.

CASE A (ADDITIONAL CASE REQUESTED FROM WASHINGTON ON 25 OCTOBER 1977)

	YEAR	OIL RATE MB/D	CUMULATIVE OIL MMB	CUMULATIVE OIL PCT STOIIP	GAS RATES MMCF/D PROD.	GAS RATES MMCF/D INJ.	CUMULATIVE GAS BCF PROD.	CUMULATIVE GAS BCF INJ.	WATER RATES MB/D PROD.	WATER RATES MB/D INJ.	CUMULATIVE WATER MMB PROD.	CUMULATIVE WATER MMB INJ.	OIL ZONE PRES PSIA
0													4405
1	1977	900	164	.8	656	427	120	78					4317
2	1978	1200	602	2.9	869	639	437	311					4220
3	1979	1500	1150	5.6	1081	852	831	622					4131
4	1980	1500	1697	8.3	1193	964	1267	974	1		1		4046
5	1981	1500	2245	10.9	1757	1527	1908	1531	8		4		3950
6	1982	1500	2792	13.6	2702		2894	1531	58	3500	25	1277	4044
7	1983	1500	3340	16.3	2702		3881	1531	221	3500	106	2555	4054
8	1984	1500	3887	18.9	2702		4867	1531	370	3500	240	3832	4030
9	1985	1500	4435	21.6	2702		5853	1531	487	3500	418	5110	4015
10	1986	1500	4982	24.3	2702		6839	1531	864	3500	733	6387	3942
11	1967	1500	5530	26.9	2702		7825	1531	1324	3500	1217	7665	3867
12	1988	1352	6023	29.3	2702		8812	1531	1690	3500	1833	8942	3752
13	1989	1027	6398	31.2	2702		9798	1531	1406	3500	2347	10220	3719
14	1990	899	6726	32.8	2702		10784	1531	1469	3500	2883	11497	3675
15	1991	711	6986	34.0	2702		11770	1531	1447	3500	3411	12775	3644
16	1992	606	7207	35.1	2702		12756	1531	1180	2500	3842	13687	3590
17	1993	572	7416	36.1	2702		13742	1531	1219	2500	4287	14600	3513
18	1994	561	7621	37.1	2702		14729	1531	1328	2500	4771	15512	3438
19	1995	491	7800	38.0	2702		15715	1531	1453	2500	5302	16425	3360
20	1996	485	7977	38.8	2702		16701	1531	1516	2500	5855	17337	3290
21	1997	374	8114	39.5	2702		17687	1531	1215	1215	6299	17781	3096
22	1998	274	8214	40.0	2702		18673	1531	913	913	6632	18114	2967
23	1999	251	8306	40.4	2702		19660	1531	648	648	6869	18351	2854
24	2000	221	8386	40.8	2702		20646	1531	549	549	7069	18551	2748
25	2001	138	8437	41.1	2702		21632	1531	255	255	7162	18644	2640
26	2002	92	8453	41.2	2702		22125	1531	172	172	7194	18676	2593

NOTES - YEARS 1 AND 26 PRODUCTION FOR SIX MONTHS ONLY

- INITIAL OIL IN PLACE USED WAS 20.5 MMSTB.

PRUDHOE BAY CROSS SECTIONAL RESERVOIR SIMULATION (BPA)

CASE 8 (ADDITIONAL CASE REQUESTED FROM WASHINGTON ON 25 OCTOBER 1977)

	YEAR	OIL RATE MB/D	CUMULATIVE OIL MMB	CUMULATIVE OIL PCT STOIIP	GAS RATES MMCF/D PROD.	GAS RATES MMCF/D INJ.	CUMULATIVE GAS BCF PROD.	CUMULATIVE GAS BCF INJ.	WATER RATES MB/D PROD.	WATER RATES MB/D INJ.	CUMULATIVE WATER MMB PROD.	CUMULATIVE WATER MMB INJ.	OIL ZONE PRES PSIA
0													4405
1	1977	900	164	.8	656	427	120	78					4317
2	1978	1200	602	2.9	869	639	437	311					4220
3	1979	1500	1150	5.6	1081	852	831	622					4131
4	1980	1500	1697	8.3	1193	964	1267	974	1		1		4046
5	1981	1500	2245	10.9	1757	1527	1908	1531	8		4		3950
6	1982	1500	2792	13.6	1412	1076	2424	1924	55	2500	24	912	4086
7	1983	1500	3340	16.3	1231	894	2873	2250	221	2500	104	1825	4130
8	1984	1500	3887	18.9	1358	1021	3369	2623	417	2500	257	2737	4158
9	1985	1500	4435	21.6	1550	1213	3934	3066	515	2500	445	3650	4182
10	1986	1500	4982	24.3	1757	1420	4576	3584	771	2500	726	4562	4179
11	1987	1500	5530	26.9	1839	1502	5247	4132	1193	2500	1162	5475	4143
12	1988	1264	5991	29.2	2066	1730	6001	4764	1533	2500	1721	6387	4100
13	1989	951	6338	30.9	2097	1760	6767	5406	1595	2500	2304	7300	4093
14	1990	801	6631	32.3	2097	1760	7532	6049	1698	2500	2923	8212	4096
15	1991	747	6903	33.6	2097	1760	8298	6691	1721	2500	3551	9125	4088
16	1992	740	7174	34.9	2097	1760	9063	7334	1412	2500	4067	10037	4111
17	1993	600	7393	36.0	2097	1760	9829	7976	1572	2500	4640	10950	4133
18	1994	494	7573	36.9	2097	1760	10594	8619	1562	2500	5210	11862	4156
19	1995	498	7755	37.8	2097	1760	11359	9261	1509	2500	5761	12775	4175
20	1996	521	7945	38.7	2051	1715	12108	9887	1524	2500	6317	13687	4197
21	1997	360	8077	39.3	2097	1760	12874	10530	1391	1391	6825	14195	4115
22	1998	333	8198	39.9	2097	1760	13639	11172	1368	1368	7325	14695	4082
23	1999	272	8298	40.4	2097	1760	14405	11815	1054	1054	7709	15079	4057
24	2000	238	8384	40.8	2097	1760	15170	12457	887	887	8033	15403	4034
25	2001	216	8463	41.2	2097	1760	15936	13100	881	881	8354	15724	4009
26	2002	204	8501	41.4	2097	1760	16318	13421	880	880	8515	15885	3998

NOTES - YEARS 1 AND 26 PRODUCTION FOR SIX MONTHS ONLY

- INITIAL OIL IN PLACE USED WAS 20.5 MMSTB.

BP Alaska Inc. 100 Pine Street, San Francisco, California 94111. Telephone (415) 445-9400

October 28, 1977

Senator Henry M. Jackson
Chairman United States Senate Committee
on Energy and Natural Resources
Washington, D.C. 20510

Dear Senator Jackson:

Following the Energy and Natural Resources Committee hearing on the morning of October 25, 1977, BP Alaska/Sohio were asked to respond to questions put by the Committee Staff. The responses to these questions are attached to this letter.

At the Committee's request we have examined the review conducted by two GAO staff members. During the hearing this review was referred to as a 'GAO Preliminary Report'. We note that this report concludes "at this point we cannot ascertain the overall effect of gas production and sales on the ultimate recovery of oil from the Sadlerochit reservoir." We have endeavored to point out in our testimony, and in answer to questions raised, that the BP Alaska/Sohio studies have shown that gas sales at 2 BCF/D, commencing when a pipeline and conditioning plant can be constructed, will have only a slight effect on ultimate oil recovery. We believe that our operating plan is sound and will result in maximizing recoveries of both oil and gas.

Thank you for the opportunity afforded to BP Alaska/Sohio to express our views on how the Prudhoe Bay Field should be produced. The Field is now on production, a Unit Agreement has been executed between the State of Alaska and the Working Interests, and a Unit Operating Agreement binds the Working Interests together in the management of the Field's resources. We feel sure that all parties concerned with the enterprise, will move forward in the future, as a Unit, towards common goals of maximizing hydrocarbon recoveries from the Field.

Yours sincerely,

M. J. K. Savage
President

Attachment

QUESTIONS CONCERNING THE PRUDHOE BAY RESERVOIR

(1) Will the produced gas available for sale by solution gas or gas cap gas?
(2) Will the production from the gas cap or solution gas significantly lower the reservoir pressure?
(3) Is a water drive occurring?
(4) Is a partial water drive occurring?
(5) If a partial water drive is occurring and the reservoir pressure is declining, what are the plans for pressure maintenance?
(6) Would declining gas cap pressure create a situation that would cause oil to be lost in the gas cap portion?
(7) Would partial water drives through a faulting system as described for the Sadlerochit reservoir bypass a considerable amount of oil if pressure depletion methods were applied too rapidly?
(8) Would gas production without re-injection cause a premature oil decline?
(9) How were the maximum production rates for oil producers determined?
(10) Does the water production indicate that a natural water drive is occurring?
(11) What cost benefits would occur from a natural water drive mechanism as opposed to the installation of a secondary recovery system?
(12) Would following normal recommended engineering practices dictate that a pressure maintenance system not be designed or installed until sufficient production and pressure history data has indicated which water drive mechanism is occurring?
(13) Would gas cap withdrawals be contrary to normal engineering practices?
(14) What is the reservoir practices in the Cook Inlet oil field area? Are reservoirs in that area similar to the Prudhoe Bay reservoirs?
(15) What was the total estimated oil production from the Sadlerochit reservoir upon which you based your proposed tariffs to the ICC?
(16) Can the estimated 400 million barrels of natural gas liquids to be produced from Prudhoe Bay be transported to markets via the Alyeska oil pipeline?
(17) If a water flood using water from outside sources is not inaugurated, because it is not deemed to be economically viable, can the initial 2.0 bcfd rate be sustained for the life of the field?

ANSWERS TO SEVENTEEN QUESTIONS CONCERNING THE PRUDHOE BAY RESERVOIR

(1) At the start of gas sales, about half the sales gas would be solution gas and half gas cap gas. Over the life of the field, however, about two-thirds of the sales gas would be gas cap gas.

Prior to gas sales, considerable volumes of solution gas will have been injected into the gas cap. It will therefore require several years of gas sales before there is any net withdrawal of gas from the gas cap.

(2) In the absence of a strong water drive, the production of either solution gas or gas cap gas will contribute to voidage of the reservoir and, therefore, will result in pressure decline. The production of oil clearly also contributes to pressure decline for the same reasons. Prior to gas sales, with produced gas being reinjected, the oil withdrawals are largely the cause of reservoir pressure decline.

(3, 4, & 5) It is too early to say whether a water drive is occurring. All the evidence indicates that the natural water drive will be a weak one.

Pressure will probably be maintained by water injection at an average level of about 500-800 psi below original pressure. At this pressure, rather than the original, the following advantages would accrue:

i) greater natural water influx from the aquifer,

ii) more efficient water injection into wells,

iii) possibly some increased recovery from water drive due to the trapped gas effect.

(6) No. Under all reasonable production schemes the gas cap expands into the oil zone. Oil is only lost to the cap if too much water in injected into the oil zone.

(7) In a water drive, some oil is likely to be bypassed, but this is not a function of pressure depletion. A prudent operator would attempt to locate this bypassed oil, and then alter his injection scheme so as to subject the unswept portions of the reservoir to flooding.

(8) No. The onset of oil decline is dictated by the field gas handling capacity. When this is reached, oil production must be restricted in order to curtail gas production, whether the gas is destined for sale or reinjection. Water injection into the oil zone helps to retard the expansion of the gas cap, and hence delays the rise in oil well gas oil ratios.

(9) Oil rates for wells have been determined, based on single well radial models and experience in other fields, that should avoid or delay the onset of high producing gas oil ratios. These rates are not fixed, but are kept under continual review in the light of well performance.

(10) There is hardly any water production as yet. It is too early to evaluate the strength of the aquifer.

(11) The more water influx nature provides, the less we have to inject, with resultant cost savings.

(12) For this type of a field, with oil that is nearly saturated with gas, and a large gas cap, it would be quite normal to wait for some analysis of reservoir drive mechanisms before installing a pressure maintenance, or secondary recovery system. We are, however, proceeding with such early design work as is feasible.

(13) Engineering practice varies widely from field-to-field according to local circumstances. Immediate withdrawal of gas would indeed be unusual and we believe detrimental to oil recovery. However, after around 25% of the oil

reserves have been recovered, we have shown that gas cap production would not be harmful, provided total gas sales are kept at a reasonable level (2 BCF/D). In some fields, where gas was returned to the formation for prolonged periods, it appeared that oil recovery lagged behind what was thought to be achievable. Water injection was therefore resorted to, with better results. We think that Prudhoe Bay would behave similarly in this respect.

(14) We are not operators in Cook Inlet so that our knowledge of these fields is scant. However, we understand that these fields contain highly undersaturated oil, lack natural water drives, and are prone to sand production problems. Conditions therefore appear to be radically different from those in Prudhoe Bay.

(15) BP Alaska Inc. has proposed no tariffs to the ICC. This question is properly posed to BP Pipelines Inc. and Sohio Pipeline Co.

(16) The amount of natural gas liquids that can be transported in the oil via the Alyeska pipeline depends on the temperature of the oil. To transport 400 million barrels

of gas liquids over the life of the field in the oil stream, would require a temperature in the neighbourhood of 110^{o}F. It has not yet been determined at how low a temperature the pipeline can be operated. Hence the transport, and indeed the extraction of the liquids from the gas, must remain uncertain at the present time. Vapor pressure requirements in tankers and in land storage tanks are also pertinent to the amount of gas liquids that can be mixed into the oil.

(17) Yes, gas sales at 2 BCF/D from 5 years on, can be sustained, for 20 to 25 years, whether water is injected or not - see BPA's Cases 1 and 2 in the testimony given at the State of Alaska hearings. Oil recovery will be little affected, whether gas is sold or not. However, oil recovery will be considerably less if water is not injected, again, whether gas is sold or not.

Department of Energy
Washington, D.C. 20585

October 28, 1977

Dear Senator Jackson:

I am in receipt of your letter of October 3, 1977, to Secretary Schlesinger regarding the Alaska Natural Gas Transportation system. He has asked me to respond and provide answers for the record of the Energy and Natural Resources Committee hearings.

As the attached answers indicate, we are firmly of the view that any early deliveries of Canadian gas should not prejudice or materially alter the gas purchases rights of any person unless that person or company agrees to such an arrangement.

Before predelivery imports will be permitted to any particular purchaser, that person must establish the capability to satisfy any requirements regarding pay back of such gas at a later time. That is the only sound basis upon which such a program could be conducted. Therefore, the rights to future imports from Alaska for the Northwest would not be given up in exchange for early deliveries of gas to any other pipeline or section of the country.

I believe that it would be inappropriate for me to comment at this time upon the particular quantity of Alaska gas that was proposed for delivery to the Northwest as I do not have all the facts at hand. The FERC will have all the facts before making a final decision certifying the sales of Alaska gas. I have every confidence that the FERC will administer the standards in a fair and reasonable manner and that the Northwest will not be arbitrarily or inequitably deprived of a share of Alaska gas.

Enclosed are the formal responses to be inserted in the record. If we can be of assistance in regard to any other questions pertaining to the Alaska gas project, please advise me.

Sincerely,

Leslie J. Goldman

Leslie J. Goldman

Senator Henry M. Jackson
United States Senate
Washington, D.C. 20510

Addendum to Transcript of the Hearing on the President's Decision and Report on our Alaskan Natural Gas Transportation System, U.S. Senate Committee on Energy and Natural Resources.

Questions (a) and (b) related to the general issue whether early deliveries from Canada would prejudice future rights of any person. It will be the policy of the Department of Energy that early deliveries of natural gas from Canada be allowed only to the extent that the particular pruchaser holds future rights to equivalent volumes of Canada or Alaska gas (or other supply) that could be used specifically to pay back to Canada the amount of the early delivered volumes, if pay back is required. No person, wherever located, will be deprived of rights to future delivery of Canadian or Alaska gas, unless such person consents thereto.

Question (c) relates to the statement on page 231 of the Presidential Report that PGT intends to deliver only 22 mmcf of 659 mmcfd to the Northwest. The 22 mmcfd amount is from the plan provided by PGT. It does not represent an Administration proposal. The final determination regarding the distribution of Alaska gas must await the execution of contracts with the producers. The FERC will review all such contracts to assure that they are consistent with the public interest. Among the public interest considerations specified in the Report at page 220 is whether any region is "arbitrarily and inequitably deprived of its share of Alaska gas." It is expected that FERC will make such decisions giving regard to the overall supply situation of the affected parties.

Department of Energy
Washington, D.C. 20461

[illegible] 1977

Dear Senator Jackson:

In attending the Senate Energy and Natural Resources Committee hearings on the President's decision with respect to an Alaska gas transportation system, we have observed the concern which has been raised by the testimony of Professor Todd Doscher of the University of Southern California regarding possible losses in Prudhoe Bay Field oil recovery due to early commencement of gas sales. The issue being raised for serious consideration by Professor Doscher, and the Legislative Affairs Agency of the State of Alaska for whom his work is being done, is whether or not the interests of the Nation, and particularly the interests of the State of Alaska, are not better served by postponing a decision on a North Slope gas transportation system for 3 to 5 years in order to observe the performance of the field, rather than making it now. This issue has been carefully considered in the course of the decisionmaking process laid out by the Alaska Natural Gas Transportation Act, and the President has decided that early action best serves the national interest. We believe early action is also consistent with the best interests of the State of Alaska. This letter provides some background on our analysis and the President's decision.

The central facts in the matter of the impact of gas sales on oil recovery are not in dispute. The initial work by H. K. van Poollen and Associates for the State of Alaska's Department of Natural Resources indicated some impact of gas sales on cumulative oil recovery, but the principal conclusions were to emphasize the effect of a water injection program on oil recovery from the main Sadlerochit Reservoir in the Prudhoe Bay Field. Of three recommendations in the 1976 van Poollen work, the first was:

> The results of this study indicate that with or without gas sales, water injection will be beneficial for increased oil recovery.

> Operators should be prepared to inject water within a very few years following start-up of the Field. 1/

Professor Doscher also emphasized the significance to cumulative oil recovery of early commencement of water injection in his first appearance before the Senate Energy and Natural Resources Committee on October 12, 1977.

Theoretically, reservoir pressure cannot be reduced at all without losing some oil recovery; pressure maintenance through water injection, whether there are gas sales or not, can minimize the loss. The supplementary work by van Poollen to aid the State in evaluating the operators' proposed development plans demonstrated that a source water injection program could be as effective, if not more so, than gas reinjection in maximizing cumulative oil recovery. We believe that all of the various simulation studies of the Sadlerochit Reservoir taken together demonstrate that a water injection pattern and development well program can be designed which will keep any loss in primary and secondary oil recovery due to pressure declines associated with gas sales to within about one percent of the original oil in place.

One of Professor Doscher's principal arguments against early gas sales is that the consequent pressure reduction might foreclose the possibility of enhancing production by a carbon dioxide injection technique now being studied for its tertiary recovery potential. The information available on this particular alternative is not encouraging. Tests have shown that the miscibility necessary to achieve any noticeable effect on oil recovery is not possible at pressures anywhere near the original pressure in the reservoir. At pressures where significant miscibility can be achieved, there is a major risk of losing more oil to the aquifer beneath the oil zone than the tertiary technique would recover. The oil industry has learned to its dismay that in miscible displacement projects it often loses as much from reduced sweep efficiency as it gains from increased displacement efficiency.

It is also possible that the acquifer would recede sufficiently that the required miscibility pressure would never be achieved. In that event, significant time, money and primary oil recovery would have been lost in a futile effort.

1/ H. K. van Poollen and Associates, Inc., Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field, January, 1976, p.6.

Ultimate oil recovery with other, more promising tertiary recovery techniques cannot be predicted with certainty at this time. However, the pressure maintenance programs incorporated into the various development plans evaluated by Van Poollen for the State of Alaska all are designed to keep the reservoir pressure to within 25 percent of its initial value, even after as much as 40 percent of the oil and up to 60 percent of the gas has been produced. At every stage in the life of the Prudhoe Bay Field, the costs of obtaining incremental production by whatever techniques are available at that time will be compared to the value of that increased production, and more will be produced as long as it is economic to do so.

The uncertainties in predicting recoveries during primary and secondary oil production have to do with how closely actual pressure distributions and flow rates within the reservoir match the predictions of computer models used by van Poollen and others who have studied the available information, and with the strength of any natural water drive which may develop within the reservoir. It is this information which will determine more precisely what gas sales rate is consistent with minimizing lost oil recovery. These uncertainties will be better understood after observing reservoir behavior for 3 to 5 years.

On the basis of the available information, both the Federal Government and the State of Alaska believe that gas sales at a rate of approximately 2.0 billion cubic feet per day (bcfd) from the Main Pool (Sadlerochit) Reservoir will be possible by the time a gas pipeline system can be built and put into operation (commencement of service is estimated to be January 1, 1983). After 3 to 5 years of operation, the level of gas sales consistent with sound reservoir management can be estimated with more precision, but there is no reason to believe that that level will be significantly different from 2.0 bcfd. At that later time, the approved gas sales rate may be either slightly higher or slightly lower than 2.0 bcfd.

The question of delaying the gas pipeline decision for 3 to 5 years was considered by one of the inter-agency working groups which submitted their reports to the President on July 1 of this year. That group's report 2/ pointed out both positive and negative aspects of delay. The President carefully

---

2/ Federal Energy Administration, Department of Commerce, U.S. Geological Survey of the Department of the Interior, Department of Transportation, Department of the Treasury, Energy Research and Development Administration. Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas. July 1, 1977, pp. 127-136.

considered this report as well as others, and decided, based on all the information available to him, that the national interest would be best served by immediate approval and initiation of a gas transportation system.

An important consideration in reaching his decision was the President's concern over the availability of oil supplies in the mid- to late 1980's and early 1990's. In describing the nature of the U.S. energy problem in his National Energy Plan 3/, the President noted that domestic oil production has been declining since 1970. Additionally, the principal oil-exporting countries will not be able to satisfy all the increases in demand expected to occur in the U.S. and other countries throughout the 1980's. In light of that limit, an important objective of a U.S. energy strategy is to encourage domestic production in order to keep imports sufficiently low to weather the period when oil production approaches its capacity limitation. Delivery of Alaskan oil and gas resources in the mid- to late 1980's and early 1990's will be an important part of the national strategy towards getting through the medium-term supply crunch caused by limits on OPEC productive capacity.

The energy delivery profiles given in the enclosed graph illustrate the significance of accelerated oil delivery and gas production in meeting the Nation's energy needs in the critical period of the mid- to late 1980's and 1990's. The two cases shown were taken from the 1977 van Poollen work, and are the gas sales case which maximizes oil recovery and the no-gas-sales case with the highest cumulative oil recovery of the ones presented. The development programs for the two cases are not the same, but these cases are illustrative of the range of energy delivery options which the Nation has in the different possibilities for production of the Prudhoe Bay hydrocarbon accumulation. The same report contains a case which delivers even more of the reservoir's total hydrocarbon energy during the critical period of the next 5 to 15 years at a cost of an additional one percent loss in primary and secondary oil recovery. However, the loss (in comparison to the gas sales case shown on the enclosure) of the additional 1.1 quadrillion btu (quads) of energy in the form of liquid petroleum is more than offset by the gain of 4.15 quads of gas energy delivered during the primary and secondary recovery period.

3/ Executive Office of the President, Energy Policy and Planning, National Energy Plan, April 29, 1977, pp. vii-xiv.

Postponing gas sales to increase primary and secondary oil recovery is not without an energy penalty. Comparison of figures out of the report for the two cases plotted on the graph shows that about 0.3 trillion cubic feet (tcf) of extra gas is consumed in reinjection during the primary and secondary oil recovery period in the no-gas-sales case. This extra gas consumption amounts to a little over 30 percent of the energy in the extra one percent of the oil which might be recovered by postponing gas sales. To the gas consumed in reinjection might also have to be added an additional loss to account for natural gas liquids which might not be recovered if gas sales are delayed.

As the van Poollen studies themselves point out, the results of the various simulation runs should be used primarily to establish the directional significance of particular aspects of development plans; the numerical values produced in the runs should not be taken too literally, as the results are determined using a number of approximations which may prove to be off slightly when actual production history has been established. What can be established from simulation runs is approximate levels of oil and gas production. The key to optimizing recoveries is maintaining sufficient flexibility in the development program that it can be altered in response to observed changes in reservoir conditions. Such flexibility is achieved by changing the locations of future development wells, and by changing rates of production or water injection at particular locations, as circumstances dictate. We have no doubt that the State of Alaska has insisted, and will continue to insist, that such a flexible development program be established and continually revised to reflect current conditions.

The national need for oil and gas supplies in the next 5 to 15 years is too great to postpone an energy resource development decision in order to evaluate more completely the possibility of saving a fraction of one percent of cumulative oil recovery during primary and secondary recovery phases. The President pointed out in his National Energy Plan that "As production (of oil resources) by conventional methods declines and oil becomes more scarce, its price will rise and more expensive recovery methods and novel technologies will be used to produce additional oil." 4/ This trend can be counted on to ensure that all oil reserves producible in the changing economic environment of world oil markets will be extracted in the course of the field's production history, irrespective of when gas sales are started. On the other

---

4/ Ibid., p. viii

hand, a prompt decision on an Alaska gas transportation system will not only ensure timely delivery of gas energy from the North Slope of Alaska, it will also ensure fulfillment of existing export contracts for Canadian gas, and increase our chances of obtaining additional supplies of Canadian gas when they are needed the most.

Although the oil and gas reserves in the Main Pool Reservoir of the Prudhoe Bay Field are the primary economic justification for early implementation of delivery systems for both oil and gas, those reserves are not the end of Alaska's North Slope resources. Alaska, and particularly the North Slope, is an important frontier area for U.S. oil and gas production. In the working group Report on Supply, Demand and Energy Policy Impacts of Alaska Gas referred to above, the Department of the Interior's U.S. Geological Survey provided estimates of undiscovered recoverable resources in the North Slope area. The table below, taken from page 19 of the report, shows additional reserves thought to be present in the Prudhoe Bay structure alone:

Expected Additions to Proved Gas Reserves
In The Prudhoe Bay Structure by 1985, tcf

	Probable	70% Value	Possible	30% Value	Total
Sadlerochit Formation	1.0	0.7	2.0	0.6	1.3
Lisburne Formation	2.5	1.8	1.5	0.5	2.3
Kuparuk River Formation	1.0	0.7	0.5	0.2	0.9
Totals	4.5	3.2	4.0	1.3	4.5

This amount of expected reserve additions is estimated to add deliverability of 0.3 bcfd. Another table from that report is presented below to provide an estimate of other North Slope resources:

Potential Gas Reserve Estimates 5/

			tcf
a.	North Slope Onshore 6/		
	Probability	95%	14
		5%	49
	Statistical Mean		28
b.	North Slope Offshore and OCS 7/		
	Probability	95%	5
		5%	50
	Statistical Mean		29

Although private company investment decisions cannot be based on projections of additions to producible reserves, the Federal Government's decision to approve an Alaska gas transportation system, or even the trans-Alaska oil pipeline before it, was and should be made with the possibility of other North Slope oil and gas discoveries in mind. We have every expectation, based on the U.S.G.S. work and other studies of possible oil and gas deposits on the North Slope, that oil and gas production from other than the Main Pool Reservoir in the Prudhoe Bay Field will be available to put through both the trans-Alaska oil pipeline and the natural gas transportation system to be built pursuant to the President's decision.

An important aspect of the decision to proceed immediately with an Alaska gas transportation system is the impact of

---

5/ "Geological Estimates for Undiscovered Recoverable Oil and Gas Resources in the United States, U.S.G.S. Circular 725".

6/ Including NPR-A, The Arctic National Wildlife Range and the area lying between them, partially leased. Not including the Prudhoe Bay geologic structure.

7/ Including the Beaufort and Chukchi Seas to water depths of 200 meters.

that decision on exploration in the North Slope area. Remote petroleum provinces such as the North Slope are expensive to develop because of the infrastructure investments which must be made to bring the hydrocarbon discoveries to market. Initial finds in any such remote province must be large enough to justify those investments. Subsequent finds can be connected to existing transportation systems at costs which are much lower relative to their unit production costs than the initial finds. However, these smaller finds can never be developed without a transportation system justified by the big ones. The initial finds must bear the costs of amortization of the transportation system, but later finds can be developed for little more than the incremental cost of connecting them with the main line system. Putting in place a transportation system with capacity available at the incremental cost of shipping another unit through provides a powerful incentive for producers to explore. This effect of a transportation system on exploration for oil and gas in the Mackenzie Delta area was a prime consideration of the Canadian Government in their negotiations with the U.S. over a trans-Canada pipeline alternative, and in their decision to approve any pipeline system at all. Access to a pipeline system justified primarily by Alaska reserves will allow Canadian producers a significantly higher wellhead price for gas discovered in the Mackenzie Delta area.

It is natural that the State of Alaska would give careful consideration to its own interests in the matter of producing Prudhoe Bay gas. Interest in adding value through processing or refining of raw materials is common to all raw materials producers. However, in assessing Alaska's interests in this particular decision, the State must consider that the cost of access to the North Slope gas is likely to be a significant component of the final cost of products derived from the gas. The Prudhoe Bay deposit is large enough to justify a transportation system which is, in turn, large enough to reduce the unit costs of access to a competitive level; a smaller scale transportation system might not allow delivery of gas to processing centers at a competitive price. Moving processing centers to the location of the resources is a concept which carries with it the high costs of construction in Arctic areas, the need for a transportation system to move products to market, and the need to establish larger communities on the North Slope to provide a labor force for construction and operation.

The real long-term benefits for the State of Alaska will come from the new exploration activity and resulting discoveries that will result from the incentive provided by large-scale oil and gas transportation systems. When hydrocarbons can be delivered to processing centers at prices approaching the marginal costs of transporting them, then the State of Alaska will not have to reduce the wellhead prices of its oil or gas in order to have a competitively viable petrochemical industry, for instance. The studies we have seen of the prospects for industrial development for Alaska suggests this approach is considerably more beneficial to the State than what Professor Doscher is recommending.

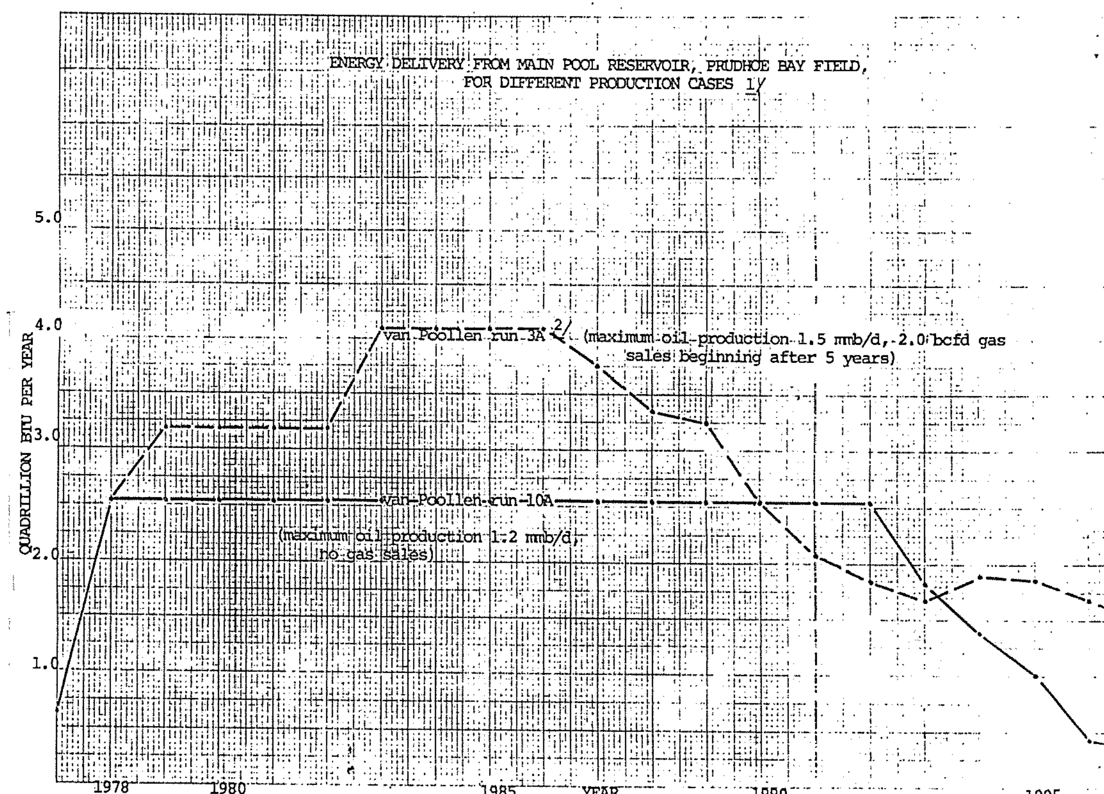
We hope these comments are responsive to the concerns which have been expressed over the wisdom of early gas sales from the Prudhoe Bay Field. The President and the State of Alaska believe that now is the time to go forward with an Alaska natural gas transportation system, and we hope you will agree. Please do not hesitate to contact us if we can be of any further assistance in this matter.

Sincerely,

Leslie J. Goldman
Deputy Assistant Secretary
Policy and Evaluation

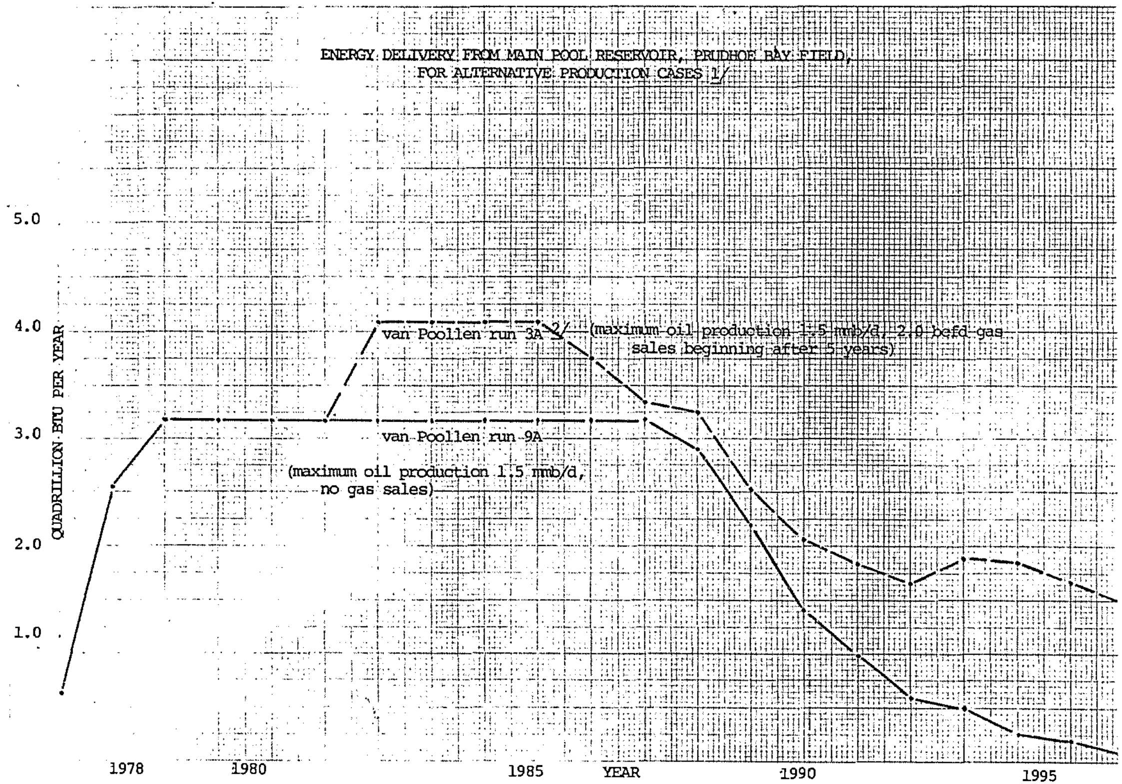
The Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

Enclosure



(Notes on next page)

98-069 O - 78 - 32



(Notes on next page)

1/ The cases plotted are representative of the spectrum of energy delivery options associated with different development programs for the Prudhoe Bay hydrocarbon accumulation. The development programs for the two cases shown are not the same.

Development programs are designed to meet oil and gas production objectives without sacrificing ultimate recovery. The components of a development program are things like timing and location of development wells, and spacing and injection rates for a water flood program. These components will be different for a development program which calls for extended oil production at a reduced rate than for one which calls for early production of both oil and gas.

The numbers were derived by converting the year-end production rates of oil and gas to British Thermal Units (Btu's). The figures would be slightly different if mid-year production estimates or the cumulative production data were used instead of the year-end production rates, but the depicted relationship of the energy delivery profiles would be the same.

2/ Energy delivery contains 53.6 thousand b/d of natural gas liquids at 4.2 million Btu/bbl.

Department of Energy
Washington, D.C. 20461

October 31, 1977

Dear Senator Jackson:

Enclosed are our answers to the additional questions on the Alcan Pipeline project that you forwarded to us under cover of your letter of October 26, 1977. We hope you will find these answers fully responsive to the concerns raised by the questions.

Please do not hesitate to contact us if we can be of any further assistance in this matter.

Sincerely,

Leslie J. Goldman
Deputy Assistant Secretary
Policy and Evaluation

The Honorable Henry M. Jackson
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Enclosures

1. Another issue that was extensively discussed during the negotiations was the settlement and payment of Native claims of the Yukon Natives. The Canadian Government has apparently made a clear public statement that settlement of Native claims in the Yukon will not delay the project and that costs of settling the claims will not be imposed on the United States consumers.

   Is the legal effect of the "clear public statement" the same as if it were included in the agreement?

   Can the agreement be amended to incorporate the statement?

A. The issue of settlement and payment of Native claims in Canada was not discussed during the negotiations between U.S. and Canadian representatives over a trans-Canadian pipeline project for Alaska gas, as the Canadian Government consistently assured us that settlement of Native claims in Canada was a purely internal matter, and that no charges against the pipeline related to the settlement of such claims will be levied. Deputy Prime Minister MacEachen made a public statement to this effect in his remarks at the signing of the Agreement on Principles between the U.S. and Canada regarding a northern gas pipeline. A copy of that public statement is attached.

   The Administration does not feel that the agreement should be amended to incorporate that statement.

Canadian Embassy
Ambassade du Canada

Information

Public Affairs Division
Direction des affaires publiques
1771 N Street, NW
Washington, DC 20036
(202) 785-1400

PRESS RELEASE

20 SEPTEMBER 1977

OTTAWA

NOTES FOR REMARKS:

AT THE SIGNING

OF THE

CANADIAN - U.S. AGREEMENT

ON THE

NORTHERN GAS PIPELINE

BY

THE HONOURABLE ALLAN J. MACEACHEN

DEPUTY PRIME MINISTER AND

PRESIDENT OF THE PRIVY COUNCIL

Check against delivery

54-77

Prime Minister, Mr. Secretary, Mr. Ambassador, and distinguished guests. The fact that we are gathered here just a little over a month since our negotiations first began to sign this historic agreement represents a truly remarkable feat.

We all recognize, however, that the tough and intensive series of negotiations that led to this agreement could not have been successfully concluded if it had not been for the massive volume of work on an infinite variety of matters related to the pipeline that was carried out over a number of years by companies, departments, agencies and special inquiries on both sides of the border.

It is clearly evident that by working together on this gigantic undertaking, both nations can derive benefits far outweighing those that either country could obtain by proceeding on its own. Construction of the pipeline itself, will provide a significant stimulus to our economies and produce a substantial number of new jobs for Canadian and American workers both in the north and throughout our industrial centres.

Over the long term, this pipeline system will, of course, provide substantial benefits by opening up one of the cheapest new sources of energy available to both countries. The decision to proceed with construction of the line will provide a strong inducement to intensified exploration and development of new petroleum reserves in Alaska and the western Arctic region of Canada. And by joining together in this vast undertaking, we will further strengthen the bond that has always existed between our two nations.

Northern residents, including native people, will over the years benefit particularly from the building of the pipeline and the related development that will follow in its wake.

At the same time, we recognize that there is a risk of social and economic dislocation during construction of the pipeline and that it will be essential to take full and effective mitigative measures to reduce this to a minimum. In order to enable the native people in the Yukon to take full advantage of the potential benefits, the Canadian government will be doing everything possible to bring about an early settlement and a start on implementation of native claims. These claims, of course, exist independently from the pipeline and will not give rise to any charges on the pipeline project. Their settlement is a purely Canadian responsibility. We as a Government are determined, however, to move expeditiously so that native rights can be effectively protected and that opportunities will be open to native people to participate in pipeline-related activites.

While governments have necessarily been very much involved in determining the terms and conditions under which this pipeline will be built, we must not forget that the project was initiated and will be undertaken by the private sector. Indeed, there was spirited competition as to which group would build the pipeline and which route would be followed. I would like to congratulate the senior officers from the Foothills and Alcan group who are present on this occasion for their fortitude, foresight and, should I say, flexibility, in coming forward with a proposed system that both countries agree will best serve our social, environmental and energy interests.

While there is a great deal of work that still remains to be done before actual construction can proceed, I think that our success in reaching this agreement on the main terms and conditions governing the pipeline system augurs well for our ability to overcome the hurdles that still lie ahead.

2. Below Whitehorse, the line will be built with greater capacity than originally proposed so that it will be able to accommodate both Alaskan and Canadian gas. If the Dempster lateral is constructed and Canadian gas is carried by the system, then the cost of service will be shared between the United States and Canada on a volumetric basis. However, if the Dempster lateral is not constructed, and no Canadian gas flows through the pipeline, the United States consumer will continue to pay for the under-utilized pipeline and excess capacity.

   Should not a provision be made for some allocation of the cost of service attributable to this excess capacity basis that gas sales would be detrimental to the ultimate oil recovery, who would be responsible for servicing the debt obtained to construct Alcan--the shippers or the consumers?

A. Installation of higher capacity south of Whitehorse in the Yukon Territory will protect the efficiency and low operating costs of the joint pipeline system when Canadian volumes are added to it. That extra capacity will provide cheap expansibility for both Alaskan and Canadian gas.

Under the design for the system as contemplated by the Agreement on Principles between the U.S. and Canada, the U.S. cost of service will actually be slightly lower in the years prior to introduction of Canadian gas into the system. Therefore, if Canadian gas is never attached to the system, there will be a net savings to the U.S. gas consumer. In the event that Canadian gas is connected to the system, we calculate that the cost of service to the U.S. consumer will still be about 15 percent lower than with the El Paso system.

3. The President's Decision concludes that Alcan can be financed without an all-events tariff placing the risk of noncompletion on the gas consumer. It is admitted that such a financing will involve a higher cost to the United States consumer because the alternative risk takers will want benefits, the commitment of equity funds at the outset and the fact that prospective lenders and investors can be expected to assign a higher risk to a system financed without a consumer guarantee, which will be reflected in a higher cost of funds, both debt and equity.

The Department of Treasury calculated what could be the cost to the consumer if an all-events tariff were adopted and the project were not completed. This is a small amount.

Moreover, the likelihood of the consumer having to pay for gas not received is practically nonexistent, since the President's Decision explicitly concludes that the risk of noncompletion is virtually a non-event.

What is the total burden of additional cost to the consumer?

What is the rationale for concluding that the pipeline should be financed without an all-events tariff, even though such a financing is certain to increase consumer costs, when the risk of noncompletion is so minimal and the cost to the consumer would be so small?

A. The financing costs allowed in the cost estimates used to project the 20-year average cost of service to gas consumers were sufficiently high that no extra allowance need be made for risk premiums or debt guarantee fees. If the financing negotiations involve some transfer of benefit in return for some type of guarantee, that transfer would amount to a re-allocation of benefit already allowed for in our cost estimates. Therefore, such transfer of benefit would involve no additional cost to the consumer.

Concluding that the pipeline should be financed without an all-events tariff is an important aspect of the circumstances which the Administration concludes will lead to an economically viable project. Consumer assumption of the non-completion risk would detract from the incentives to project sponsors for timely and efficient completion of the project.

Another aspect of the decision against an all-events tariff was uncertainty about the legal status of such a tariff. The lenders contacted in the course of our analysis were skeptical about a noncompletion feature of an all-events, full cost of service tariff. Because such a tariff might involve charges prior to the time that the "used and useful" tests have been met, lenders assumed an immediate court challenge to Federal Energy Regulatory Commission approval of such a tariff, and extreme reluctance by State public utility commissions to pass such a tariff through to consumers. The uncertainties associated with likely litigation over the all-events tariff actually detracted from the financeability of the project. The lenders much preferred a financing package which included regulatory features that were in line with accepted practice, and which assured maximum incentives to maintain economic viability of the project.

4. Dr. Schlesinger indicates the producers will be paid a fee for their loan guarantees in the event that form of producer financial participation is adopted.

How much is included in the estimated delivered 20-year average rate per Mcf? Will such fees be capitalized as part of the construction costs on which a return will be allowed?

A. As mentioned in the answer to Question 3, we feel that the financing costs included in the cost estimates used to compute the cost of service for the pipeline projects are adequate to cover any loan guarantee fees. Therefore, no specific amount is included for such fees in the estimated 20-year average cost of service used in the decision analysis.

If actual financing arrangements involve such fees, those fees would be capitalized as part of construction costs on which the return will be allowed. However, we believe that the costs of the fees, capitalization, and the return thereon will be adequately covered by the financing costs which we have allowed in our cost of service estimates.

5. How do you propose to obtain the participation of Alaska and the gas producers in the financing of the project, in view of the repeated statements by Alaska and the gas producers that they have no intention of participating in the project?

A. The North Slope gas producers from time to time have indicated varying degrees of interest in participating in an Alaska gas project. SOHIO and EXXON were members of the study group which was a predecessor of the Gas Arctic project. ARCO has said it would consider participation in some phase of a pipeline project, such as the gas processing plant. In the question and answer period following his testimony on October 14, Claude Goldsmith of ARCO expressed the belief that his company would be more willing to particpate in financing the pipeline project if the wellhead price were allowed to be deregulated.

Our hope that the State of Alaska will be interested in participating in the financing of the project is based on its expressed intention to participate in the financing of the El Paso project in the event that it had been the President's choice. The State's willingness to participate in the El Paso project was based on the State's assessment of the benefits of the project for the State, and we are hopeful that the State will also see considerable potential benefit from implementation of the Alcan project.

As discussed in the financing chapter of the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, the producers and the State of Alaska stand to gain substantial benefits from implementation of a gas pipeline project. We are hopeful that their perceptions of these benefits will lead them to whatever participation in the project that is necessary to get the project implemented.

6. The gas pricing provisions of the President's <u>Decision</u> calls for the enactment of gas pricing provisions contained in the National Energy Plan (NEP) even if the NEP is not enacted.

   What does this mean?

   Does it mean that the FPC, or FERC, must adopt the pricing provisions of the NEP, including the wellhead price and the allocation of costs only to lower-priority users?

A. The decision calls for a gas pricing approach similar to that contained in the National Energy Plan because the President believes that those policies are fair and equitable. For the same reasons, we feel that the National Energy Plan gas pricing provisions will be enacted. We do not feel that it is appropriate to speculate what might happen if the NEP is not enacted.

7. In determining the cost to the consumer, the measure has always been the cost of transporting Alaskan gas to selected points in the United States by the proposed delivery systems. However, the appropriate criteria to use is the total cost of gas to the U.S. gas consumer generally under each of the alternative proposed systems. This is the only real measure of the true impact because it taken into account the use of existing pipelines in the lower 48 States which are increasing underutilized.

   What is the impact when evaluated in this way?

A. The Administration does not agree that the appropriate criterion to use for comparing Alaska gas transportation systems is the total cost of gas to the U.S. gas consumer generally under each of the alternative proposed systems. The logical extension of this argument would be that all new gas sources would have to first be transported to the producing areas which are served by existing gas pipelines, and then transported through those existing pipelines to markets. This kind of analysis does not seem to us to be appropriate.

   It is appropriate that regulatory authorities take into account use of existing pipelines in the lower 48 States when those pipelines are a direct means of moving new sources of gas to markets. Use of existing pipeline systems with lower costs than installation of completely new systems should show up in a reduced cost of service for delivering particular gas sources to market. The most cost-effective transportation method for each new source of gas has to be judged according to the cost of moving that particular source of gas to markets.

8. The Agreement on Principles commits both countries to seek legislation to remove any delays or impediments to timely and efficient construction.

   The U.S. has such legislation. ANGTA provides for expeditious granting of certificates, permits, etc. ... and for waivers of law where necessary.

   Canada has yet to adopt implementing or expediting legislation.

   What provision is made, in the event of delays which arise because Canada is unable to enact such expediting legislation, for Canada to assume the additional costs of delay?

- A. The most significant assurance that we have of Canadian concern over delays, and the increased costs that such delays cause, is that the Canadians themselves will be users of this pipeline. The Canadians have a strong interest in assuring that the pipeline is constructed expeditiously and efficiently, in order that their own Mackenzie Delta gas reserves can be made available to Canadian gas consumers on economically competitive terms.

   The Canadians' incentives to limit delays operates in two ways. The first is through the direct impact on the wellhead price of Mackenzie Delta gas of the costs of constructing the segments of the project which will be used by both Canadian and U.S. gas reserves. Additionally, the cost-sharing arrangement on the extension of the Dempster Lateral from Dawson to Whitehorse is tied to cost over-run performance in constructing the main pipeline. To the extent that the Canadians are successful in keeping costs on the main line down, U.S. shippers will pay a higher proportion of the cost of service on the so-called "Dawson Spur."

98-069 O - 78 - 33

The need for legislation to limit delay is somewhat different in Canada than it is in this country. The laws governing environmental regulation in Canada are substantially different from those in this country. Also, the possibility of a successful legal challenge of a National Energy Board decision, particularly when ratified by the Canadian Parliament, is rather narrow. A discussion of the limited possibilities for challenge of the NEB decision in the Canadian courts was presented in testimony given by Lawrence R. Raicht of the State Department before the House Subcommittee on Indian Affairs and Public Lands last April. We have attached the portions of that testimony which dealt with possible legal challenges in Canada.

Legal Challenges

The question has been raised as to the nature and scope of possible court challenges in Canada to any NEB decision. We cannot predict with certainty what may happen in the Canadian courts should an NEB decision be challenged. Predicting the courts in any jurisdiction is a risky business, and Canadian case law is not as well developed as US law. However, we have studied Canadian law and procedure, and have discussed this question with Canadian officials. We are reasonably confident as to the broad outline of Canadian law and practice in this area.

There are some fundamental differences between the U.S. and Canadian legal systems. The most important here is that the Canadian constitution, the British North America Act of 1867 (BNA Act), does not impose limits on the exercise of parliamentary power of the kind represented, for example, by our 5th Amendment. The BNA Act sets out classes of subjects as falling within the legislative powers of the federal or provincial legislatures. Within their respective legislative spheres, the federal and provincial legislatures are supreme. For example, section 92 of the BNA Act grants the provinces exclusive legislative jurisdiction over direct taxation, provincial borrowing, management of provincial lands, provincial prisons and other institutions, marriages, property, and civil rights and education. Section 91 of the Act gives the Federal Parliament sole jurisdiction over such matters as regulation of trade and commerce, military matters, Indians and Indian lands, and all other matters not exclusively assigned to the provinces and related to the peace, order and good government of Canada. Thus, a Canadian law might be found unconstitutional in the sense that the legislative body which enacted it, either federal or provincial, did not have power to legislate on the subject matter involved. However, if the legislative body had such jurisdiction, its enactments cannot be overturned by the Courts.

In this case, the jurisdiction of the federal Parliament to pass laws relating to transit pipelines and to native rights and claims is quite clear. Accordingly, there appears to be no possibility that Canadian federal legislation on these matters could be invalidated in the Courts.

Except for constitutional review of the limited kind I have described, most rights to judicial review arise under statute. Parliament could, and has on occasion, done away with all judicial review of the merits of administrative actions, although it appears that Parliament cannot do away with judicial review of action falling outside of the administrative agency's jurisdiction.

There are two existing procedures for seeking review of NEB decisions, although, as noted, Parliament could revise or suspend these procedures altogether. First, Section 18 of the NEB Act permits parties to NEB proceedings to appeal questions of law or jurisdiction to the Federal Court of Appeals of Canada. Such appeals are discretionary for the Court; a court must grant leave to appeal. An application for appeal must be filed within one month of the NEB's action, unless the court or a judge finds that special circumstances allow some longer time. Once leave is granted, the appeal must be entered within 60 days.

As noted, such discretionary appeals can involve only questions of law or jurisdiction. As we understand Canadian law, there should be no plausible challenge to the jurisidiction of the NEB or any significant question of law arising from its decisions. Section 44 of the NEB Act gives the NEB broad discretion in deciding on applications for certificates of public convenience and necessity for pipelines.

Judicial review of NEB action would more likely be sought under the Federal Courts Act. Under that Act, the NEB could be overturned if it "failed to observe a principle of natural justice", "acted beyond or refused to exercise its jurisidiction", "erred in law in making its decisions", or "based its decisions or order on an erroneous finding of fact that it made in a perverse or capricious manner or without regard to the material before it."

We understand that the Canadian courts have left great discretion to the administrative board or body involved. Indeed, we know of no case in which an NEB decision to issue a certificate of public convenience or necessity has been effectively challenged in the courts.

It should also be noted that Canadian law places comparatively stringent limits on standing to sue. We understand that, in general, only parties to Administrative proceedings can seek judicial review of agency action. Accordingly, suits by environmental and public interest groups have not played a particularly signficant role in Canada.

We are not aware of other Canadian laws or regulations which might provide a basis for litigation to prevent pipeline construction if the Federal Government decides to approve a transit pipeline. Any transit pipeline would have to meet a number of legislative requirements in addition to NEB approval. The Government must approve acquisition of pipeline rights of way over territorial lands in the Yukon and Northwest Territories pursuant to section 19F of the Territorial Lands Act. Further, any pipeline project must meet the requirements of the Foreign Investment Review Act. However, each of these procedures involves a very great measure of administrative discretion, and we do not believe there is a realistic possibility of litigation to block a pipeline project to which the Government is committed.

The Department has no information about what efforts the Government of Canada may be considering to facilitate pipeline construction if it is decided to approve a pipeline project. However, it seems reasonable for Canada to await the decision before determining what measures, if any, are needed to implement it.

Settlement of Native Claims

It is the policy of the Federal Government of Canada to recognize the existence of a native interest in those areas of Canada in which the native interest has not been settled by treaty or superseded by law.

9. Mr. Bosworth states in his testimony that if the legislative package which the "Canadian Parliament approves is not fully compatible with the obligations that the Canadian Government has taken on in this agreement, clearly we would have to take another look at it."

What would our options be in this case?

A. The answer to this question is very much a function of what is contained in the legislative package which the Canadian Parliament does approve. If the Canadian Government cannot obtain approval from their Parliament of the Agreement on Principles negotiated between the U.S. and Canada, then clearly there is no agreement. In that event, the U.S. and Canada would have to try to negotiate another agreement which would be acceptable to the legislative bodies in both countries.

10. Will United States industry and labor have equal access to compete in supplying materials and labor on the Canadian segment of the pipeline?

A. Under Canadian law, Canadian firms must be given first preference for the supply of goods and services to pipeline projects in Canada. HOwever, the Agreement on Principles between the U.S. and Canada contains a provision that each government will endeavor to ensure the supply of goods and services to the pipeline project will be on generally competitively terms. These two considerations together mean that, to the extent that American firms can supply goods and services on portions of the project in Canada cheaper than Canadian firms can supply the same goods and services, those American firms will have access to the contracting work involved in the Canadian segment of pipeline.

Under the provisions of the Agreement, either government may institute consultations with the other in cases where it appears that the "generally competitive" objectives are not being met. The Office of the Federal Inspector in this country will have facilities for receiving complaints by American firms that they are able to supply goods and services cheaper than the firms to which contracts are awarded in Canada. When demonstration if an award on non-competitive terms can be made, the Federal Inspector will in the course of his ongoing consultations with his Canadian counterparts institute an inquiry proceeding with appropriate Canadian authorities. In the event of a positive finding, remedies to be considered include renegotiation of contracts or reopening of bids.

11. Mr. Bosworth indicates in his testimony that "the question of the tariff or the rate that will be charged is yet to be addressed by the rate-making authorities in the respective countries, in our case the FPC; in their case the National Energy Board." At an informal conference on September 30, 1977, with, among others, certain members of the FPC staff, Clyde Hargrove, attorney for Northern Border Pipeline Company, et al., stated at TR 26, lines 11-14, "This pipeline is not going to raise any money or get anything built until the Commission hits that document and says, this tariff is approved and when you file it, it becomes effective." Does the Administration contemplate the tariff will become effective well in advance of the time gas begins to flow?

    Mr. Bosworth states in his testimony that "the all-events, full cost-of-service tariff" encompasses liability for noncompletion, etc.

    If the tariff is to become effective as Mr. Hargrove suggests, are not the consumers, in effect, guaranteeing the project's completion?

A. The Administration does not contemplate that the pipeline tariff will become effective in advance of the time gas begins to flow, to the extent that "to become effective" means that charges would be collected from gas consumers. The structure of the pipeline tariff to be charged once gas has begun to flow may well be approved in advance of the time that gas service actually begins. Gas consumers will not be required to guarantee the project's completion.

12. Several reasons are cited as to why the United States will not have to face an unreasonably high cost-of-service tariff imposed by the Canadian National Energy Board. Mr. Bosworth states, "That is a subject over which the U.S. regulatory authorities retain control." Dr. Schlesinger states that the "tariff must ultimately be accepted by the FPC, which can refuse to certificate the project if the tariff is inappropriate."

What type of protection is this?

What recourse does FERC have other than to prohibit the inclusion of Canadian costs in the rate the U.S. companies charge their customers? This could result in either (1) bankrupting the U.S. companies or (2) causing the flow of gas to stop; neither alternative appears to be viable.

A. The most complete discourse on this point was given in a colloquy between Chairman Dingell and the staff of his House Energy and Power Subcommittee, and a panel of the U.S. Shippers Group in a hearing on September 23, 1977.

There are two different situations in which the relationship of Canadian regulatory authorities to charges paid by U.S. gas consumers need be considered. The first is the tariff approved initially by the National Energy Board for the segment of the pipeline project in Canada. The primary protection that the U.S. consumer has is that the Federal Energy Regulatory Commission (FERC) has to approve the passthrough of the transportation charges in Canada to interstate gas consumers. Therefore, the shippers will not sign transportation contracts or agreements with Canadian pipeline companies which contain features which are objectionable to U.S. regulatory authorities. In the words of Mr. H. L. LePape, President of Pacific Interstate Transmission Company,

> . . . our (transportation) agreements . . . will be subject to our ability to pass those costs on down through, and the subject regulatory approval from the U.S. authorities. So we will not be signing transportation agreements without having the total package, all the way down through the regulatory processes to pass these costs on to our customers. Nor will we be putting equity into the pipeline and making investments until we have that full package.

The second problem is whether or not the National Energy Board might change the tariff arrangement after the pipeline was constructed and in place. In this event, the recourse is indeed that FERC could only prohibit the inclusion of Canadian costs in the rate the U.S. companies charge their customers. In the event of such prohibition, there would be the risk of real pressure on the U.S. shippers. However, it is in such a situation that we would have to depend on the long-standing commercial relationships that we have had with the Canadians in a variety of different areas to guarantee that a workable solution could be found. As there is considerable American investment in Canada, plus the fact that both countries already transport considerable quantities of their energy supplies across the territory of the other, we are confident that any such difficulties could be worked out.

The record in House hearings, particularly the testimony of the Panel of U.S. shippers on September 23 referred to above, is suggested for more detail on these points.

13. Mr. Blair states that the tariff can only be changed with the consent of the NEB. He describes the tariff charges and concludes that the dollars per Mcf resulting will be a "calculation rather than the tariff itself." These statements appear to conflict since the indications are that the tariff will be a cost-of-service which amount will vary from month to month and from year to year. With which statement does the Administration agree?

A. The Administration does not believe that the two statement conflict.

When Mr. Blair says that the tariff in Canada can only be changed with the consent of the NEB, he is referring to the structure of the tariff. That structure is expected to be a cost-of-service tariff. The costs which go into determining the cost-of-service are expected to change from time to time, however, particularly the operating costs. Therefore, the actual dollar amount of the tariff will change as the costs of providing the service change, even though the tariff structure does not change.

Final determinations on the nature of the tariffs to be charged on both Canadian and American segments of the pipeline project have not been made. It is expected that the tariffs will be cost-of-service tariffs, in line with recent practice for large supplemental gas projects.

14. Mr. Altman makes it abundantly clear that there is no firm assurance that the project can be privately financed and that there are no back-up plans.

    Assuming arguendo that it cannot be privately financed, will the Administration resort to governmental participation, deny the lower 48 of badly needed gas, or what?

A. The Administration is convinced that the project can be privately financed under the conditions that we expect to prevail. Mr. Altman was a prime participant in the analysis which led to that conclusion, and it is our impression that he believes that the project can be privately financed. In these circumstances, the Administration sees no need for back-up plans, or speculation on what the Administration might do if its expectations turn out to be wrong.

15. Dr. Schlesinger states there are no pipelines of 48- or 54-inch diameter in the Yukon. The Dempster will not be of 48- or 54-inch diameter.

Are there any in Canada? Is this a basis for noncomparability?

A. It is our understanding that the guarantee of "similar" treatment provided by the Transit Pipeline Treaty is not confined to pipelines which are precisely the same in all characteristics. Our interpretation, and we believe that of the Canadians, is that "similar" treatment means that the computation of charges on pipelines within the same taxing jurisdiction will be based on similar methodology. In the event that any Canadian pipelines in the Yukon were of lesser diameter than the pipeline for delivery of Alaska gas, the test of "similar" treatment would be that, when the charges on the smaller pipeline were scaled up to the larger size according to the same methodology, they would be the same as the charges applicable to the Yukon portions of the Alaska pipeline.

16. Dr. Schlesinger indicates that $25 billion of gas in the North Slope "is virtually costless."

Does that assume all sunk costs are allocated to oil? Is that consistent with past regulatory practices?

A. Secretary Schlesinger's statement with respect to additional costs associated with gas production from the Prudhoe Bay Field were not intended as prescriptions of regulatory practice. His point was simply that, from an investment perspective, the revenues to be derived from gas sales by both the producers and the State of Alaska will be very large in comparison to the investment expenditures required to realize those revenues.

17. Dr. Schlesinger in his testimony discusses ranges of rates of return to encourage efficiency.

How will the resulting return (i.e., higher than normal for efficient construction and lower than normal for inefficient construction) be carried through to subsequent rate proceedings? Ten years from now, won't the NEB or FERC allow, in a rate proceeding, whatever then is an acceptable return to equity, thus disregarding either efficiency or inefficiency?

A. The kind of consideration contained in this question about implementation of the variable rate of return on equity has been the subject of considerable discussion already between U.S. and Canadian regulatory authorities. The variable rate of return concept, while agreed upon in principle as an important incentive in encouraging efficiency in pipeline construction management, has not been worked out in detail. Design of a detailed variable rate of return incentive scheme is left to the Federal Energy Regulatory Commission (FERC) and the Canadian National Energy Board (NEB).

A discussion of our most recent thinking on implementation of the variable rate of return concept is attached. The kinds of complications of future rate proceedings cited in this question would be avoided by applying the variable rate of return only during the construction period. Allowing the rate of return to vary over a wide range during that period, then to settle on a normal rate of return for projects of this type after the pipeline is complete and in operation, would provide a significant incentive for efficient construction without complicating future improvements to this particular pipeline system, or other projects that the sponsor companies might be involved in.

VARIABLE RATE OF RETURN

The variable rate of return is a device intended to create a real incentive for the pipeline project owners (sponsors) to build the system at the lowest possible cost and in the shortest possible time, while providing gas consumers with relatively assured cost-of-service charges. While the details have been left to the Federal Energy Regulatory Commission (FERC) to develop, it is anticipated they would adopt something similar to the following plan:

(1) In accordance with Finance Condition 2 in Section 5 of the President's Decision (p. 36), the FERC would use the direct capital cost estimates (in 1975 dollars), the proposed time schedule for outlays, and the company-projected capital acquisition program, all filed with the FERC immediately prior to certification, as input data for providing a rate base at the time of completion under an assumed rate of inflation and AFUDC rate. The cost of equity capital used to develop the AFUDC rate would be a normal rate which reflects anticipated market conditions and includes a risk premium to compensate equity investors for the risk they bear by having their equity at risk throughout the life of the project.

(2) Upon completion of construction, but prior to leave to open, the projected rate base in (1) shall be reestimated using the original 1975 dollars costs and timetables, but the interest rates and the rates of inflation which reflect actual borrowing cost, capital market conditions, and inflation experience.

(3) The reestimated projected rate base in (2) shall be compared to the actual rate base proffered by the company and a determination of the extent of rate base overage or underage should be made. The cost of equity capital used in the AFUDC rate by the company shall then be adjusted upward or downward, depending on whether there was an underage or overage and the final rate base shall be redetermined using actual outlays and timing with the AFUDC rate based upon actual borrowed funds and costs and the adjusted rate of return on equity determined above. This final rate base shall be determinative of the cost of service charges to be levied by the pipeline on shippers.

(4) This procedure shall be applied to each company owning a section of the Alcan system on a company-by-company basis. The FERC may wish to modify (3)

to reflect the expectation that filed costs and schedules are likely to be overrun. They may, for example, choose to permit the "normal" equity rate from (2) to be earned if the actual rate base is a certain percent over the reestimated projected base, with the higher rate allowed if the actual ra base is below this target level.

Our current thinking is that the variable rate of return mechanism should only be operative during the construction period.* It is expected that the rate of return permitted in (4) would vary substantially with overages or underages. The reason for requiring a large range is that this is necessary to create a significant incentive. With some care a rate of return to rate base overrun trade-off function can be develope that provides both a high return for the pipeline equity owne

*An alternate version would make the variable rate of return on equity operative throughout the life of the project. While this would substantially narrow the range of possible rates of return and still provide a significant incentive scheme, it has at least two undesirable side affects. First, it would be operative years beyond the construction period, requiring the FERC to adjust the company's "normal" rate as market conditions change. While this would be possible, it extends the adjustment into a period well beyond the time over which behavior was to be affected. Second, if any of the companies which jointly constitute the Alcan system were to undertake activities other than the construction and operation of the original system (including system expansion), it would be necessary to segregate the original equity capital from either reinvested income or new capital in order to keep the adjusted rate of return from affecting the financing of these activitie Again, while this is possible, it seems much cleaner to make a one-time adjustment to the initial rate base, as suggested in the procedure above, and then treat the equity thereafter in a normal fashion.

<u>and</u> a cost of service lower than anticipated by shippers if a significant underage occurs. Alternatively, it would result in a low rate of return to keep the rate base down if a significant overrun occurs. Thus, the variable rate of return will not only create an incentive to keep costs low, but also absorbs a portion of cost overruns, thereby cushioning the cost-of-service impact on consumers in the event overruns occur.

18. Assuming that Canadian gas continues to flow from the MacKenzie Delta after Alaska gas ceases, what is equitable in requiring U.S. consumers to pay for the cost of service of the Dempster lateral if they receive no gas?

Mechanically, if no gas flows to Northern Border or through the Western Leg, how will U.S. companies recoup these costs?

A. The Agreement on Principles with the Canadians only provides a cost allocation formulation. As long as a cost-of-service is being paid to transport U.S. gas through the Canadian portions of the pipeline system, that cost-of-service will bear an agreed upon share of the cost-of-service of the extension of the Dempster lateral from Dawson to Whitehorse ("the Dawson Spur"). However, when Alaska gas ceases to flow through the pipeline system, there will be no cost-of-service being paid by U.S. shippers to which the cost-of-service of the Dawson Spur can be allocated, therefore there will be no liability for U.S. shippers to continue to pay cost-of-service on the Dawson Spur.

19. Mr. Hargrove in his testimony states that the shippers who buy the gas have a "full right to be heard before the NEB" regarding rates. Has the Administration sought to assure these rights or will the NEB later preclude the shippers' participation?

A. The Agreement does not specifically address the issue of participation in National Energy Board (NEB) proceedings by U.S. shippers. However, we have no reason to believe that the NEB is contemplating a procedure which would preclude participation by the shippers. If an issue involving participation in NEB proceedings should arise, it could be the subject of consultation, under the terms of the Agreement, between the United States and Canadian regulatory bodies, and between the governments.

Regardless of who participates in NEB proceedings Article 4 of the Transit Pipeline Treaty requires that pipeline tariffs and regulations be just and reasonable, and non-discriminatory.

20. Question:

In connection with the United States consumer paying for the cost of service of the Dempster lateral, it is not true that, under current NEB policies, the American consumers are paying for this twice; once as a direct cost-of-service payment and again based on the "value" of gas at the border?

A. U.S. consumers of Alaska gas will be paying a share of the cost-of-service of an extension of the Dempster Lateral from Dawson to Whitehorse ("the Dawson Spur"). There is currently no expectation that any of the gas which will be transported by the Dawson Spur, namely gas from the Mackenzie Delta, is destined for markets within the U.S. Current expectation is that all of the Mackenzie Delta gas will go to markets in southern Canada. Should that expectation change, the question of the American consumer paying twice for transportation of gas through the Dawson Spur will be raised in the context of negotiations over appropriate pricing policy for the export of Mackenzie Delta gas to U.S. markets.

21. Does the Administration agree with Mr. Millard's testimony before the Senate Energy and Natural Resources Committee that it is inappropriate for the producers to accept the risk of noncompletion but that it is appropriate for the producers to participate in overrun financing?

A. The context of Mr. Millard's referenced remark is not clear, and Mr. Millard himself should be consulted for elaboration of his remarks.

The Administration believes that the appropriate role for the producers is in assuring that sufficient financing is forthcoming on competitive terms to assure completion of the project. The only circumstances that the Administration can envision in which the project might not be completed would be if sufficient financing was not available for completion. The role of the producers in the financing would simply be to eliminate those circumstances.

Considerable discussion of a possible role for the producers in financing a transportation project was held during the course of hearings before the House of Representatives. We have attached the letter that we sent to Chairman Dingell of the House Subcommittee on Energy and Power containing some questions and answers which elaborate on the Administration's views regarding an appropriate role for the producers in financing.

Department of Energy
Washington, D.C. 20585

October 18, 1977

Dear Mr. Chairman:

At the hearing on Friday, October 14, 1977, several general questions were raised concerning the financing of the Alaska Natural Gas Transportation System and the role of the producers therein.

The following questions and answers are submitted to supplement the record and amplify the Administration's position in the matter.

Q. What general considerations underlie the financing concepts set forth in the President's Decision?

A. The Decision and Report of the President reflects a belief that the economic risks of an Alaska gas project can and should be borne by the private sector. There has been considerable attention given in the course of the decision process to the risk that the project might not be completed because the borrowing capacity of the sponsoring companies could be inadequate to support cost overruns. Analysis of the experience of financing the Alyeska oil pipeline project supports an opinion that non-completion is not a significant risk and that there is more than enough debt support capacity among the direct beneficiaries of the project to insure that completion financing would be forthcoming. Alyeska was financed essentially through a "project financing." Additional financing on competitive terms was forthcoming for the project even as cost overruns mounted because lenders were convinced of the continued economic viability of the project. In the case of the gas pipeline, the lenders will have the additional assurance that the gas sales will be contracted prior to commencement of construction.

In this context, the President found that the project should be privately financed and that North Slope gas producers, as one of the major direct beneficiaries of the project, might usefully be part of a financing plan.

Q. What role does the Administration foresee for the producers?

A. The details of the Alcan financing plan are not yet worked out. The variables include capital supply and demand at the time final financing arrangements are made, the perception of the financial markets regarding project risk, and the sale price of the gas. However, the outlines of the plan presented by the President appear to be achievable and consistent with experience in comparable projects. Some role for the gas producers in the final financing plan clearly would facilitate financing. For example, such a role might consist of a guarantee of a portion of cost overrun financing thereby insuring that the project would be completed. Lenders for the base financing might thereby be willing to rely upon the project, including the gas sales contracts, as adequate assurance. The producer participation, in any event, need not be open-ended in amount and could not be open-ended in time. The Decision requires that the producer liability cease at project completion. In the final analysis, the nature of the producer role, as well as any compensation for it, is a matter which must be left for negotiation among the interested parties and review by appropriate regulatory agencies.

Q. Is there a realistic likelihood that the producers would be willing to participate in the financing?

A. The North Slope gas producers from time to time have indicated varying degrees of interest in participating in an Alaska gas project. Sohio and Exxon were members of the study group which was a predecessor of the Gas Arctic Project. Arco has said it would consider participation in some phase of a pipeline project, such as the gas processing plant. In the question and answer period following his testimony on October 14, Claude Goldsmith of Arco expressed the belief that his company would be more willing to participate in financing the pipeline project if the wellhead price were allowed to be deregulated.

Q. What consideration was given to the financial capability of the producers to participate?

A. The capacity of the producing companies to participate in financing the project will vary considerably. At one extreme, Sohio's financial position is well known. At the other extreme, no limit on financial capability has ever been suggested as a reason why Exxon might not participate in the financing of a gas pipeline project. As Mr. Goldsmith pointed out in his testimony and answers to questions, Arco's ability to participate is constrained by restrictions in its indentures. The suggestion in the Report that producer participation would be a reasonable method for facilitating financing contained no specific statements on the degree of involvement of any particular company. However, revenues from gas sales will be significant for all three companies. It can be expected that lenders to the producers would take those revenues into consideration when reviewing debt restrictions, as North Slope oil revenues must have been considered for Sohio during its recent financings.

Q. What control could producers have over cost overruns. Aren't they being asked to sign a "blank check?"

A. Under the terms of the Decision and the Justice Department report and letter, the producers would be permitted to exercise control of the project directed toward the minimization of cost overruns. For example, their participation in the project could be conditioned upon adherence by the pipeline company to certain contracting procedures, reporting requirements, advance capital arrangements, levels of contingency financing, or such other reasonable conditions that would provide producers with oversight of construction. The Decision does not contemplate that producers would blindly sign "blank checks" or that such would be required for successful financing.

If there are additional questions, please advise me.

Sincerely,

Leslie J. Goldman

The Honorable John Dingell
Chairman
Energy and Power Subcommittee
House Interstate and Foreign Commerce Committee
Washington, D.C. 20515

22. Mr. Bosworth, in his testimony, states that in some instances, the Canadian properties will be jointly owned by Canadian and American companies

What are the instances?

A. We understand that the referenced statement by Mr. Bosworth is from an exchange with Representative Collins on September 22, 1977, during a joint hearing of the House Commerce Subcommittee on Energy and Power and the House Interior Subcommittee on Indian Affairs and Public Lands. In response to Mr. Collins's question about who will own the section of the pipeline project going through Canada, Mr. Bosworth replied:

> (It will be owned) By a consortium of private companies, including Canadian companies and American companies in some instances.

The inclusion of American companies as possible owners of portions of the pipeline in Canada refers to the allowance for possible participation of U.S. companies in the capital structure called for by the Canadian National Energy Board (NEB).

In their July 4th decision, the NEB required a restructuring of the companies which will construct the pipeline in Canada. That decision called for creation of a federally-chartered holding company which would be the owner of 100 percent of the pipeline in the Yukon Territory, and 51 percent of the pipeline in the three Western Provinces which it would traverse. The other 49 percent of the capitalization of the project in the three Provinces would be through new companies formed by the Canadian pipeline companies operating within the respective Provinces.

The NEB would require that 51 percent of the stock of the four companies created to own the project - one federally-chartered company for the Yukon and majority ownership of the project in the three Provinces, and three companies for minority ownership within three Provinces - must be owned by Canadians. The other 49 percent ownership in all four companies would not be restricted. Therefore, American firms could be part owners of any of those four companies.

23. What provision, if any, has been made for reimbursement in the event of expropriation?

A. The pipeline in Canada will be owned by Canadian companies, and a large fraction of their capital will be Canadian. The U.S. will be purchasing a transportation service from those companies for our gas across Canada. There is nothing of ours to expropriate except the gas in the pipeline, and there is little reason to expect that Canada would take that.

24. The President's Decision concludes that one of the benefits of the Alcan system is that prebuilding of the pipeline in southern Canada will enable Canada to export its current surplus of gas from Alberta with payment being made by swap or exchange of future Alaskan gas, thus providing gas in the critical period before Alaskan gas is available.

Has Canada entered into any commitments?

A. The Canadian Government has not made any commitments to export its current surplus of gas from Alberta, as the consent of Alberta regulatory authorities for such an arrange- must be secured. Proposals for export of that gas are currently pending before the Canadian National Energy Board, contingent on agreement to prebuild project facilities in the southern portions of the system. We assume that discussions are currently being held between the Canadian Federal Government and the Government of the Province of Alberta over whether or not to approve these proposals.

25. Under Canadian law, the Federal Government of Canada cannot agree to the export of Alberta gas without the agreement of the Province of Alberta. Canadian newspaper articles indicate that Alberta is not interested in approving any exports to the United States unless the United States will agree to concessions on tariffs for agriculture and petrochemical products.

Has Alberta agreed to the export of surplus gas to the United States?

Is the United States involved in negotiations with Canada or Alberta concerning the type and magnitude of trade concessions?

A. As mentioned in the answer to the previous question, we assume that discussions are being held between the Government of the Province of Alberta and the Canadian Federal Government with regard to the export of surplus gas to the United States. To our knowledge, Alberta has not agreed to such exports at this time.

With regard to negotiations over trade concessions, the first point is that the U.S. Federal Government does not negotiate with the Provincial Government of Alberta. Any discussions regarding terms of trade would be held between the U.S. and Canadian Federal Governments in the context of the Multilateral Trade Negotiations. Agricultural products and petrochemicals tariffs are currently being discussed in the Multilateral Trade Negotiations, but as yet there is no specific proposal from the Canadian government. If there is a proposal, the U.S. government will respond to that proposal.

A bilateral arrangement between the U.S. and Canada to accommodate Alberta's concerns is extremely unlikely. Under U.S. law, any trade concession by the U.S. must be matched

98-069 O - 78 - 35

by a corresponding trade concession from its other major trading partners. Additionally, part of the ground rules of the multilateral trade negotiations is that any concession made to one trading partner must be made to all participants in the negotiations. Thus, any proposal from Canada intended to facilitate agreement from Alberta to export of surplus gas to United States will receive the closest scrutiny to assess its costs to U.S. industry.

26. Why should the facilities to deliver the surplus gas be part of the Alcan project vis-a-vis ATGL and/or Westcoast's own current expenditures in order to deliver the gas to the border? If they are Alcan project facilities, will all the cost of service be charged to California consumers?

A. Under Canadian pricing policies for natural gas, purchasers of that gas will pay for the transportation system for delivery of that gas in the export price of the gas itself, regardless of whether or not the facilities to deliver that gas are part of the Alcan project or part of the Canadian partners current expenditures on expansions of their own systems.

U.S. pricing policy for gas involves a wellhead price plus a transportation charge. However, Canadian pricing policy is to set a delivered price for the gas; the wellhead price is determined by subtracting the transportation cost from the delivered price. The cost of the gas to California consumers, or any other U.S. consumers for that matter, will include the cost of transporting the gas to the U.S. border, regardless of what facilities are used for that transportation.

27. Mr. Millard states in his testimony that specific negotiations with lenders will require obtaining final agreements on various matters, including among others, "any compensation to producers for other services."

Is this the "compensation" to "induce them to underwrite cost overruns? Do you agree with Mr. Millard's statement? If so, how many cents per Mcf should be added to the Alcan cost of service to afford a fair comparison with El Paso's?

A. Mr. Millard himself should be queried for additional details regarding his testimony before the Committee. We do not know specifically what he had in mind when he mentioned, ". . . any compensation to producers for other services."

For the cost estimates used in developing and presenting the President's decision, liberal allowances were made for the cost of debt and equity capital for financing the project. The cost of debt capital used was 10 percent, and the cost of equity capital was 15 percent after income taxes. We believe that these costs are sufficiently high that any compensation to suppliers or guarantors of financing should be covered by these rates. Therefore, no addition to Alcan's estimated cost of service is necessary.

28. Mr. Millard also states in his testimony that "conditions in capital markets are subject to rapid change and the precise terms of a financial agreement are not fully predictable one year in advance."

Does the Administration agree that the capital markets are volatile?

If the markets are volatile, would this mean that there is a reasonable probability of the necessity of governmental participation?

A. The Administration believes that conditions in capital markets are reflected in changing interest rates and in the terms of covenants between lender and borrower which are a normal part of raising capital.

The fact that interest rates move and debt restrictions change over time does not alter the fundamental point that financing capacity is available in the private financial markets to complete the Alcan project. The Administration does not think there is a reasonable probability of, or even a necessity for, governmental participation.

29. Mr. Millard indicates that the participation of "suppliers of materials to the projects" in the financing may be necessary.

Does the Administration agree? If yes, how would they be compensated? How much has been included in the average 20-year rate? Would U.S. suppliers have to support the Canadian portion even though they are supplying no goods and service in Canada?

If no, why not?

A. Mr. Millard did discuss participation in financing the project of "suppliers of materials to the projects" with the Alaska Gas Project Coordinator staff and others within the Administration in the course of meetings regarding the Alcan project. The examples he used when discussing this matter with us were installment purchases from equipment suppliers and export financing under the auspices of governments who desired that their nationals and firms provide materials and equipment to the project. Any such financing would be in accordance with the normal commercial terms which generally govern such financing. As we discussed in our response to previous questions, we believe the costs of debt financing allowed for in the cost estimates prepared by the staff for this decision will cover these normal charges.

As to the supply of goods and services in Canada, any supplier credits, or credits provided by the home country government of any supplier, would only be for financing the goods actually supplied to the project. Therefore, supplier financing in Canada would be for materials and equipment supplied for the portions of the line in Canada. If not materials and equipment are supplied from outside of Canada, then no supplier credits or supplier country government credits, would be available for the portions of the line in Canada.

30. Mr. Millard states in his testimony that under certain circumstances, it "would be necessary to turn back to seek additional consumer or U.S. Government support on a limited scale to cover overruns caused by general economic conditions or social obstacles."

Do you also foresee that there are circumstances when the Alcan pipeline could not be privately financed?

If so, what are they? If not, why not? If private financing is not feasible, how would the project be financed?

If consumer financing or government participation is required, have arrangements been made with the Government of Canada for Canada's participation in a comparable manner?

A. We do not know what circumstances Mr. Millard had in mind in which he thought it " . . . would be necessary to turn back and seek additional consumer or U.S. Government support on a limited scale to cover overruns caused by general economic conditions or social obstacles." We do not foresee any circumstances in which the project should be undertaken but could not be privately financed. No arrangements need to be made with the Government of Canada for participation in a comparable manner because no circumstances are envisioned in which government participation would be required.

As far as consumer financing is required, the line that has been drawn is that consumers will not be required to assume the non-completion risk. Certain consumer risk-bearing may be a feature of the tariff finally approved by the Federal Energy Regulatory Commission (FERC), to the extent that such risk-bearing is consistent with current Commission practice.

Details of the tariff structure filed with the National Energy Board (NEB) in Canada will also be made available to the FERC in accordance with its responsibility for approval of transportation contracts between the U.S. shippers and the Canadian pipeline companies. FERC will not allow the companies to pass through charges which are not in accordance with acceptable regulatory practice in this country. Knowing that, the U.S. shippers will not sign transportation contracts with Canadian pipeline company owners involving a tariff that the U.S. shippers know is unacceptable to FERC.

31. Mr. Monte Canfield testified that the Agreement with Canada should be amended to provide the U.S. with access to the progress of construction in Canada. GAO's analysis of the Alyeska experience demonstrated that regularized audit procedures is a necessary precondition to expeditious and efficient construction

Does the Administration agree that regularized audit procedures are necessary?

Does the Administration agree that the U.S. should have unencumbered access to Canadian records?

If yes, does the Administration intend to amend the Agreement with Canada to give the U.S. access?

If not, why not?

Is the Administration considering any other mechanisms to assure access to records? If yes, please describe them in detail, and their legal effect in the event of noncompliance.

A. The Administration agrees that regular audit procedures are vital to expeditious and efficient construction. In addition, the Federal Power Commission (FPC), both in the Initial Decision of the Administrative law judge and in the Recommendation to the President by the full Commission, stressed the importance to reducing regulatory risks of periodic audits and timely rulings on rate base treatment. The successor to the FPC, the Federal Energy Regulatory Commission (FERC), will establish such in conjunction with the Federal Inspector, as soon as the organization of the Federal Inspector is sufficiently complete to allow such activity to proceed.

As regards the situation in Canada, the Canadian National Energy Board (NEB) is the relevant regulatory authority for pipelines in that country. The United States now receives about 2.7 billion cubic feet per day (bcfd) of Canadian gas through Canadian pipelines constructed under the surveillance of the NEB. Experience with those pipelines has been good, and there is no reason to think experience with this joint pipeline project will be substantially different.

The Agreement on Principles between the United States and Canada provides for close consultations between regulatory authorities in both countries. This cooperation and consultation will range from matters of testing programs for pipeline structural integrity to exchanging of appropriate information on environmental safeguards. Establishing some type of uniform system of accounts will undoubtedly be one of the subjects of consultation between FERC and the NEB. The Canadians have assured us that, in the course of these consultations, any relevant documents will be made available. The Administration sees no need to amend the agreement with Canada to give the U.S. specific access to Canadian records.

32. Assuming _arguendo_ that the Alcan project is constructed and the State of Alaska postpones the sale of the gas on the basis that gas sales would be detrimental to the ultimate oil recovery, who would be responsible for servicing the debt obtained to construct Alcan--the shippers or the consumers?

A. The Administration believes that, based on all of the available information, there is an overwhelming probability that at least 2.0 billion cubic feet per day (bcfd) of pipeline quality natural gas will be available from the Main Pool Reservoir in the Prudhoe Bay Field to transport through an Alaska gas pipeline project by the time that the project is completed. We also believe that substantial additional gas will be available from other accumulations on the North Slope by that time.

The Administration also agrees with Senator Stevens's view, as expressed in the hearing before the Senate Committee on Energy and Natural Resources on October 25, 1977, that the final assessment of the degree of deliverability risk will be made in the course of attempting to arrange financing for the project. If the financial community is not satisfied that there is virtually no risk that insufficient gas will be available to operate the pipeline as an economically viable venture, then financing will not be forthcoming and there will be no project. The question regarding who would be responsible for servicing the debt in that event would simply not be relevant - there would be no debt because nobody would lend money to the project.

33. The gas transported through the Alcan line will be relatively rich in hydrocarbons other than methane. Are there any plans to separate these components from the gas at any point along the pipeline route?

34. Will the producers retain the right to separate natural gas liquids from the gas on the North Slope, as is common practice in the Lower 48, for petrochemicals manufacturing in Alaska or for alternative means of transportation?

A. Questions regarding disposition of natural gas liquids produced along with the gas out of the Prudhoe Bay Field are a matter for negotiation among the producers, the State of Alaska and the gas pipeline project. These questions will be worked out in the course of negotiating gas sales contracts and the ownership of the gas processing plant, as well as ownership of the products of that plant.

October 25, 1977

Dr. K. T. Koonce, Operations Manager
Western Production Division
Exxon USA
Houston, Texas

Dear Dr. Koonce:

At the Energy and Natural Resources Committee hearing this morning on the Alcan Pipeline proposal questions to be answered in writing were submitted for the Record. I would appreciate your response to the following:

1. Could you describe what is presently being done with the natural gas liquids from Prudhoe Bay?

2. Will you allow an independent petroleum engineer to review your simulated computer runs? To complete new ones?

3. Have you completed any studies of the feasibility of gas reinjection and early implementation of a water flood?

Would you provide the Committee with these studies?

4. The existence of low residual saturation to gas invasion appears to be a pre-requisite for successful implementation of the proposed operating plan. Yet studies sponsored by the operators apparently contradict the existence of this condition.

In the face of your studies, how do you justify existence of these necessary conditions?

5. The operator's plan relies heavily on the assumption that there is low residual oil saturations in the Saddlerochit. Yet the operators are planning a small scale test of water injection to get information on the actual residual oil saturation to water encroachment. Why is such a test necessary? If such a test disproves your assumption, and if gas re-injection is necessary to maintain pressure, what can you do to assure no loss of oil?

6. High vertical permeability is apparrently another pre-requisite for success of the proposed operating plan. Have you used a standard published technique for measurėng in-site vertical permeability in the vicinity of a well? Why not?

7. How much oil will be left behind in the reservoir at the completion of production under the present production plan?

What are your plans for getting this oil out through tertiary recovery?

8. How can you justify such a firm conclusion on production of 2 bcf/day of gas when you can't reach a conclusion on when to begin water injection?

Because of the time constraints, I trust you will submit your answers in writing to the Committee as sonn as possible and certainly no later than Monday, October 31, 1977.

Thank you for your consideration.

Sincerely,

John A. Durkin

JAD/cbw

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 • HOUSTON, TEXAS 77001

PRODUCTION DEPARTMENT

October 31, 1977

Senator Henry M. Jackson, Chairman
Committee on Energy and Natural Resources
United States Senate
1307 Russell Senate Office Building
Washington, D.C. 20510

Dear Senator Jackson:

At the hearing conducted by the Senate Committee on Energy and Natural Resources on October 25, 1977, Exxon was requested to supply answers to specific written questions and pertinent supplemental information on the reservoir management plan for the Prudhoe Bay Field. In response to these requests, Exxon submits the documents identified on the attached list and respectfully requests that this full submittal be included in the record.

I want to make it clear that Exxon's goal is to maximize recovery of oil and gas at Prudhoe Bay to the extent prudently possible. We believe that such a goal is in the common best interest of all concerned - the Nation, the State of Alaska, and the producers. To this end, and in recognition of the significance of Prudhoe Bay, Exxon and the other owners have considered and will continue to consider many alternative plans.

Exxon's studies were based on an enormous amount of preproduction reservoir description information, so far as we know, more than for any other petroleum discovery in history. With this great wealth of data, our technical staff, which has access to experience gained in all types of oil and gas fields around the world and has available the most advanced reservoir engineering techniques, has painstakingly and exhaustively studied a myriad of operating alternatives seeking the best overall plan to achieve maximum recovery of the oil and gas. This foundation of information and knowledge allows us to confidently state that the plan is well conceived and will not adversely affect oil recovery. The owners have purposely designed a plan which provides flexibility to respond to observed performance, and we are confident that gas sales of 2 billion cubic feet per day commencing with completion of a gas transmission system will not adversely affect ultimate oil recovery from the field.

A DIVISION OF EXXON CORPORATION

Attachment A is a critique of Dr. Doscher's testimony and report. The significant concerns that we have with the testimony and report are as follows:

- Dr. Doscher asserted that up to 2 billion barrels of oil could be lost by the gas sales plan approved by the State of Alaska. Exxon's studies indicate that the approved operation plan provides adequate flexibility to permit gas sales of 2 billion cubic feet per day without adversely affecting ultimate oil recovery. All producers and consultants who have actually studied Prudhoe Bay reservoir performance in some detail support the approved operating plan for the field, including early gas sales.

    - Dr. Doscher said in his report and reiterated in his testimony before the Committee that the low residual oil saturations in the gas-invaded region represent the "most crucial" issue in the production plan. The fact is, however, that the effect of gas sales timing on oil recovery is <u>not dependent</u> on these saturations.

    - Dr. Doscher suggested in his report and in his appearances before the Committee that the producers' relative permeability relationship for oil and gas is overly optimistic and cannot be supported by field histories. Industry data (see Attachment A) published as far back as 1955 indicates that the Prudhoe Bay gas/oil relative permeability relation is not optimistic. The key point is this: the justification for selling gas as soon as a transmission system can be made available at 2 billion cubic feet per day <u>is not predicated</u> on this relationship.

- Dr. Doscher asserted that up to 4 billion barrels of tertiary recovery potential may be lost by approved gas sales. Although there has been considerable research and field testing of tertiary recovery processes over the last 25 years, no known tertiary recovery process would be applicable on a large scale at Prudhoe Bay. Further, it is unlikely that any tertiary recovery process applicable at Prudhoe Bay would be significantly impacted by the timing of gas sales. The producers are fully aware of the significant potential for tertiary recovery, not only at Prudhoe Bay but in many other fields, and maintain vigorous research programs in this area.

  Dr. Doscher suggested the possible use of carbon dioxide as a miscible tertiary recovery agent. He recognized the problem of supplying the necessary volumes and proposed to burn 2 billion barrels of oil to generate the carbon dioxide. However, he did not refer to published correlations which, when applied to Prudhoe

Bay crude oil, indicate that carbon dioxide is miscible only at pressure levels well above the initial reservoir pressure. In short, the utilization of carbon dioxide as proposed by Dr. Doscher is completely inappropriate for this reservoir.

- Dr. Doscher suggested that a gas line may never be needed if the Trans-Alaska Pipeline could be converted to two-phase flow when oil rates from Prudhoe Bay decline. The technical and operational problems associated with two-phase flow in a 48-inch diameter pipe traversing 800 miles and several mountain ranges are prohibitive. Attachment B is an analysis of this proposal prepared in conjunction with Exxon Pipeline Company, one of the TAPS owners.

- Dr. Doscher suggested that there is no immediate need for Prudhoe Bay gas in the Lower 48. It is abundantly clear that this Nation faces a current and growing shortage of natural gas. The 2 billion cubic feet per day of gas pipeline deliveries planned from Prudhoe Bay is equivalent to the total daily residential consumption in all 17 states having members on the Senate Energy Committee.

The Committee staff working with the GAO also concluded from an admittedly cursory review of several consultant studies that unanswered questions exist. Attachment C addresses each of those observations. Other specific questions posed in writing by Senator Durkin, Senator Hansen, and the Committee staff are answered in Attachments D, E, and F.

In conclusion, Exxon, Atlantic Richfield, and BP Alaska independently studied many operating alternatives in selecting the plan proposed to and approved by the State of Alaska. Several of Exxon's simulation study results are tabulated in Attachment G. These results illustrate how the reservoir can be managed to achieve maximum recovery within the proposed gas sales plan. The conclusions reached by Exxon and the two operators are supported by findings of three independent consultants. Results of these studies have been considered by the State of Alaska Joint Gas Pipeline Impact Committee, the Division of Oil and Gas Conservation, and the Federal Power Commission in consenting to gas sales from Prudhoe Bay. In addition, six other federal agencies have reviewed study results. These governmental entities have uniformly concluded that sufficient flexibility exists in the operating plan to ensure that early gas sales will not adversely affect oil recovery.

In Exxon's view, the Committee should move forward in its consideration of the gas pipeline with confidence that the owners of Prudhoe Bay, in cooperation with appropriate state regulatory authorities, have the ability to properly manage the reservoir to achieve maximum recovery of oil and gas.

Sincerely,

K. T. Koonce

K. T. Koonce

KTK:ms

Attachments

c: Members of the Committee
on Energy and Natural Resources

Attachments

Attachment A - Critique of Doscher/Dougherty Report

Attachment B - Feasibility of Two-Phase Flow in TAPS

Attachment C - Comments on GAO Review

Attachment D - Response to Senator Durkin's Questions

Attachment E - Response to Senator Hansen's Questions and Transcript of Mr. L. G. Rawl's Testimony Before the Joint House Subcommittee on October 11, 1977

Attachment F - Response to Committee Staff/GAO Questions

Attachment G - Effects of Gas Sales on Oil Recovery

ATTACHMENT A

CRITIQUE OF
"REVIEW AND ANALYSIS OF THE PROPOSED OPERATING PLAN AND OF THE STUDIES AND COMPUTER SIMULATIONS OF THE DYNAMICS OF THE SADLEROCHIT RESERVOIR"
BY TODD M. DOSCHER AND ELMER L. DOUGHERTY, JR.
AND TODD M. DOSCHER TESTIMONY BEFORE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Introduction

In the report prepared by Dr. Doscher and Dr. Dougherty and in Dr. Doscher's testimony before the Committee on Energy and Natural Resources, a recommendation was made to defer the decision to approve a gas pipeline from the Prudhoe Bay Field. From an analysis of the report and testimony, it appears there are four major reasons why Drs. Doscher and Dougherty think the pipeline decision should be deferred. These are:

1. Up to 2 billion barrels of oil could be lost under conventional operations.

2. The opportunity for tertiary recovery operations could be missed resulting in the loss of an additional 4 billion barrels of oil.

3. The gas could be shipped through TAPS with the oil when oil rates decline.

4. The Prudhoe Bay gas is not needed in the lower 48.

This critique has been prepared to present evidence that these suggested reasons are not valid.

The report and testimony also included some errors and apparent misunderstandings of the Operators studies, some of which are discussed in this critique.

Critique

1. Up to 2 billion barrels of oil could be lost under conventional operations.

The contention that selling gas from the Prudhoe Bay Field will cause the loss of 2.0 billion barrels of oil reserves is pure conjecture. The evidence upon which this contention is based is from case studies conducted by Engineering consultants which assume field operating plans so much different from that actually planned that the results are irrelevant.

Throughout the report prepared by Drs. Doscher and Dougherty, many references are made to the uncertainties associated with model studies. Emphasis is placed on their uncertainty that the residual oil saturations behind the gas invaded region as predicted by the Operators can be achieved. As will be discussed in more detail, the decision to sell gas is not impacted by these saturation levels, and to that extent, is a moot point.

Following are statements from Drs. Doscher and Dougherty's report and from testimony presented by Dr. Doscher regarding these points and comments in rebuttal to those statements.

(a) Doscher Testimony, October 12, 1977

Page 316, Line 5 - Dr. Doscher's response to a question by Senator Jackson was that 2 billion barrels of oil would be lost as the result of gas sales.

Rebuttal Comments

Dr. Doscher has grossly overstated the potential adverse effects of gas sales on oil reserves. The case study he has selected to demonstrate this effect is based on a field operating plan which is so significantly different from the approved plan that it has no relevance.

The extremely high loss quoted by Dr. Doscher is apparently based on a case reported by Dr. H. K. van Poollen which assumed gas sales of 4.0 BCF/D beginning after 2.75 years of oil production. The approved operating plan for the Prudhoe Bay Field provides for gas offtake necessary to sell only 2.0 BCF/D as soon as the gas transmission system is available, estimated to be about 6 to 7 years from now.

As Exxon testified at the State of Alaska Field Rules hearings in May, 1977, a maximum potential effect of 1.3 percent, or about 280 million barrels was observed for a case with 2.0 BCF/D gas pipeline deliveries starting after 5 years of oil production compared to delaying gas sales until after 15 years. Other cases presented by Exxon at the same hearing indicated this potentially adverse effect could be prevented by changing other variables in the operating plan such as water injection.

Dr. H. K. van Poollen's studies also indicate the same oil recovery can be achieved with and without gas sales. A conclusion drawn in Dr. van Poollen's report entitled "Prediction of Reservoir Fluid Recovery Sadlerochit Formation Prudhoe Bay Field, Supplement A" and dated February, 1977 is: "The offtake rates of 1.5 MMSTB/D for oil and 2.0 MMMSCF/D for gas sales, as proposed in the plan of operations submitted to the State by the operators, appear to maximize the oil recovery according to the results of his study."

The selection of operating plans which are so different from the approved operating plan has no significance. It only serves to create confusion and not add to substantive facts.

(b) The report contains three references designed to show that gas sales cause significant oil losses. As will be discussed, the examples are not representative of the actual operating plan and are not pertinent to the decision to sell gas at the approved rate.

Statements from Doscher's Report

Page 35 - "Van Poolen, (sic) on the other hand, shows a significant effect of gas sales on recovery efficiency when sales are increased from 2 to 3 and then 4 billion cubic feet a day. The recovery efficiency is gradually reduced from 41 percent to 32 percent (a loss of 1.9 billion barrels). Again, Van Poolen (sic) does not give a case without gas sales that can be directly compared with the three runs just cited. Extrapolation of the results of these three cases to zero gas sales would suggest that the recovery efficiency would increase to 9.1 billion barrels, or 47.7 percent of the oil in place.* Such explicit extrapolation is not justified, but the implicit trend certainly is in the absence of any other information."

"*Core Laboratories, Inc., in their report prepared for the Alcan Pipeline Company present results of mathematical simulations which show a monotic (sic) decrease in oil recovery from 8.36 billion barrels of crude oil to 6.23 billion barrels as the gas sales are increased from 0 to 4 billion cubic feet a day."

Page 36 - "It is worthy of note that H. J. Gruy and Associates also found a significant difference in recovery with and without gas sales, the effect of no gas sales being such as to raise the recovery efficiency from 29 percent to 39 percent even without waterflooding."

Page 48 - "Both the van Poolen (sic) and Core Laboratories studies indicate a substantial effect of increased gas sales on decreasing oil recovery."

Rebuttal Comments:

The operating plans in the case studies above which purported to demonstrate the effect of gas sales on oil reserves are so far different from the actual operating plan that the results are not germane.

The van Poollen studies which are reported are based on early simulation cases which assumed gas sales beginning after 2.75 years at rates up to 4.0 Bcf/D and water injection volumes actually decreasing with increasing gas offtake rates. Dr. van Poollen subsequently ran cases which coincided more with the operating plan that was being proposed by the operators. Dr. Doscher did not use the more up-to-date studies reported by van Poollen in February, 1977. The results of his subsequent runs substantiated the operators' conclusions that the maximum oil recovery could be achieved with gas sales of 2.0 Bcf/D.

The Core Laboratories case results are also based on operating plans far different from the approved operating plan for the field. They assumed gas sales up to 4.0 Bcf/D beginning after 3.5 years. There were other significant differences in the way they operated the field in their model and the way it will actually be operated including:

(1) All the water was injected into the aquifer instead of the oil reservoir as now planned. Injection into the aquifer is not as effective in maintaining oil rim pressure or in sweeping the reservoir, and

(2) The limiting water-oil ratio was restrictively low in their studies, reducing benefits of waterflooding.

Core Laboratories in their report and stated "the oil recoveries resulting from no gas sales can be approached by a combination of limited gas sales, water injection, and adjusting the field operating limits based on performance of the reservoir." These are the steps which the operators' plan proposes to initiate.

Why no mention was made of Core Laboratories conclusions in the Doscher and Dougherty report is not understood.

The recovery factors quoted from H. J. Gruy and Associates study for the Department of Interior are apparently based on cases which compared gas sales at a maximum rate of 4.0 Bcf/D starting 3 years from the start of oil production to no gas sales ever. Other significantly different operating plans assumed in these particular Gruy cases are:

(1) 320-acre spacing versus 160-acre spacing.
(2) Oil offtake of 2.0 million B/D versus 1.5 million B/D.
(3) Gas-oil ratio limit of 6,000 CF/STB versus 40,000 CF/STB.

H. J. Gruy ran additional cases using much more realistic field operating conditions. Those cases indicate a maximum effect (even though Gruy assumed 2.5 Bcf/D sales after 4 years) of gas sales on oil recovery of 380 million barrels (case 22 vs 23). In the report to the Department of Interior describing the study results it was stated: "It is reasonable to suppose that the small percentage difference in oil recovery forecast between the two cases would be reduced even further through practical experience gained in operating the field."

Dr. Doscher failed to refer to both the more representative cases run by Gruy and the conclusion drawn in the report to the Department of Interior.

(c) Dr. Doscher and Dr. Dougherty make many references to the relative displacement efficiencies of gas and water and to residual oil saturations left behind gas and water fronts. These are important considerations relating to waterflood volumes and timing but not to the timing for gas sales. The fact that they attach so much importance to the saturations in recommending that the gas sales decision be delayed cannot be understood, in terms of sound reservoir management principles in that it ignores the numerous alternatives which are available to operate the field so as to recover oil and gas reserves.

Following are several comments from the report referring to the saturations behind the gas front and rebuttal comments.

<u>Statements from Doscher's Report</u>

<u>Page 17</u> - "When the operators' curves were used in the simulation studies, the residual oil to gas invasion in the areas where gravity stabilizes the displacement falls to values well below 20 percent, the average significantly less than the end point residual saturation reported by Van Poolen" (sic).

"This result from the operators' simulation studies <u>is the most crucial one in their representation</u> of the preferred operating plan, since it provides the basis upon which expansion of the gas cap is chosen as the preferred operating scheme for the Prudhoe Bay Field" (emphasis added).

Page 22 - "Should the reservoir performance be considerably different from that which is anticipated, then the opportunity for revision will exist only if the necessary options are still available. Thus, it does not appear prudent at this time to commit to the withdrawal of gas from the reservoir for pipeline sales until it is certain that such sales will not interfer with the adoption of possibly superior production schemes."

Rebuttal comments:

The statement on page 17 misses the point entirely. The decision on the timing for a gas sale is not dependent on the residual oil saturation in the gas invaded areas. If it did turn out, for instance, that the residual oil saturations actually observed were higher than predicted, the operating plan could be altered to include a larger volume of water injection at an earlier date than now envisioned being necessary to recover the oil.

The plan for operating the Prudhoe Bay Field is consistent with sound conservation practices. It has been designed to take advantage of the best recovery mechanisms available, either natural or induced.

Reservoir surveillance programs and field tests will provide the data needed to evaluate the relative displacement efficiency of gas versus water, and the field operating plan has the flexibility to be modified to take advantage of the best drive mechanism. The decision to sell gas now does not alter that flexibility.

(d) In the report and in testimony before the Energy Committee, there were many misconceptions regarding the gas-oil and oil-water relative permeability relationships developed by the operators. The comments made by Dr. Doscher and Dr. Dougherty tend to cast doubt on the credibility of the techniques used and the results obtained.

Doscher testimony October 12, 1977

Page 326, Line 4 - "It is based on their use of a relationship between oil and gas based on some laboratory experiments which we do not believe will be attained in actual practice during the rather short life of the field."

Statements from Doscher's Report

Page 14 - "The data is obtained by simultaneously flowing the two fluids through the core until an equilibrium condition is reached."

Page 14 - "On the other hand, the reliability of data obtained on composite cores (a series of small cores butted against back other), which were used by the operators to develop the oil-water relative permeability data, has not been established in the technical literature. The multiple end effects encountered at each joint may have an effect on the derived values for the relative permeability."

Page 16 - "By plotting and extrapolating their results on semi-logarithmic graph paper versus saturation on a linear scale (relative permeability on a logarithmic scale versus saturation on a linear scale) they obtain a continuous curve which can be extrapolated down to very, very low values. The corresponding relative permeability values are several orders of magnitude below a value of 0.01 (an approximate lower limit to laboratory measured values of relative permeability)."

Rebuttal Comments:

The procedures ascribed to the operators, presumably Exxon, were not correctly described by Doscher. Firstly, two types of techniques were described by Exxon in meetings held in San Francisco on June 6, 1977 between the operators and Dr. Doscher and Dr. Dougherty. These were gas floods and water floods on composite samples of preserved samples of Prudhoe Bay cores butted end to end and centrifuge tests on preserved cores to measure relative permeability to oil. In floods of composite core, only gas or water were injected into the core not "simultaneously flowing the two fluids through the cores until an equilibrium is reached" as stated by Dr. Doscher on Page 14, Line 6, of his report. Use of gas or waterflooding techniques in measuring relative permeabilities is old and well established in the literature.[1,2,3,4] Also, the technique of butting cores end to end to minimize capillary end effects (commonly called the Penn State technique) is old in the art and is a standard technique used by industry.[5,6,7] In Exxon's core analysis procedures, the faces of the cores are machined flat and a force is applied in the apparatus to force the samples into capillary contact. This procedure eliminates capillary end effects between core samples. Further precautions are taken in the core analysis procedure by increasing the flow rate and hence the applied pressure drop near the end of the flooding test. This procedure minimizes capillary end effects at the outlet face of the composite core as low oil saturations are approached at the end of the flooding tests. Use of high rates to suppress capillary end effects is also old in the art.[3,4,8]

The importance of carefully preserving core samples to prevent alteration of waterflooding behavior was presented to industry in 1954.[9] The techniques of core preservation have been adopted by most of industry. Hence, the techniques used by Exxon are well documented in the literature and are widely accepted by industry.

We conclude that Dr. Doscher did not understand Exxon's description of their flooding techniques for relative permeability measurements, most of which have extensive descriptions in the literature, and, therefore, his explanation of the results is incorrect.

Exxon also described a technique of measuring relative permeabilities to oil in which a preserved core sample initially containing a low water saturation and high oil saturation is spun under water in a centrifuge cup. Although this technique has not been described in the literature, the principles used in the procedure are familiar to those skilled in the art.[10] The increased gravitational forces resulting from the high, constant centrifuge speed causes water to flood the core. Relative permeabilities to oil are calculated with Darcy's Law using the rate of oil production and the applied hydrostatic head of the water. As shown in Figure 1, relative permeabilities to oil measured on preserved Prudhoe Bay cores by the centrifuge technique are in good agreement with those from the composite technique, see Figure 2. (The core used in the centrifuge was also part of the composite core used in the water flooding test.) Note that the measured values in both the waterflooding and centrifuge techniques extend to values of 0.1 percent or 0.001. Thus, Dr. Doscher's statement on Page 16, Line 20, that an approximate lower limit of laboratory measured values is 0.01 is not correct.

Dr. Doscher's paragraph beginning on Line 16, Page 16 of his report concerning gravity drainage does not reflect all of the principles of gravity drainage developed in the literature.[11,12,13] Simple hand calculations using procedures published in the literature could have been performed to show that reasonable saturation profiles are obtained in the reservoir simulator using the relative permeability data derived from laboratory tests. Average saturations of 28 percent in the gas-invaded region predicted by the simulator can be checked quickly by simple hand calculations.

Dr. Doscher's statement on Page 326, Line 4 of his testimony which states that the laboratory data used by Exxon will not "be attained in actual practice during the rather short life of the field" is not supported by laboratory and full data. In fact, Figure 3 shows a plot of gas-oil relative permeability ratios measured in the laboratory and used in reservoir simulators for Prudhoe Bay on a figure published by Arps for the ranges of values published by industry.[14] The Prudhoe Bay data are far less favorable for oil recovery than the average and are slightly less favorable than the minimum curve of Arps. Dr. Doscher's suggestion that Exxon's data are optimistic is totally without foundation.

(e) In the report by Dr. Doscher and Dr. Dougherty there is a great deal of discussion regarding the level of oil saturation achieved by gravity drainage. As has been previously discussed, the level of oil saturation achieved does not impact decisions to sell gas, and for that reason is a moot point. There are, however, contraditions between the report and testimony which should be pointed out. In addition, it should be pointed out that statements made to the effect that residual oil saturations predicted for Prudhoe Bay cannot be supported are in error, and there are misunderstandings regarding the operation of fields other than Prudhoe Bay in the report also.

Doscher testimony October 12, 1977:

Page 326, Line 14 - "Over the shorter life of the field, we do not believe and cannot find any evidence that such has happened in actual practice, that there will be such a low residual oil saturation in the expanding gas cap. We cannot verify this in actual practice."

Page 329, Line 10 - "The operators suggest that the residual oil saturation will be low, extremely low, 15 to zero percent. We believe it will not be low. We believe that it will be of the order of 35 percent or that pore space."

Page 330, Line 1 - In response to questioning by Senator Bartlett, Dr. Doscher stated that the residual oil saturation in the oil column depleted of oil production would approach zero. He further stated that he could not find any reservoirs where it had approached zero and that the lowest he had knowledge of was in the order of 25 or 30 percent.

Statements from Doscher's Report

Page 17 - "Certainly, the results reported by Exxon for the Hawkins Woodbine reservoir in 1975 tends to support the concept that residual oil can be driven down to extraordinary low values by gas cap expansion -- gravity drainage."

Page 18 - "On the other hand, the permeability of the reservoirs sands is very high, 1,194 mds. for the Louisville member and 3,396 mds. for the Dexter (6 to 17 times greater than that of the Sadierochit)."

Page 19 - "It is worth noting that operators of the Hawkins Field in opting for enhancing recovery from the field by gas injection into the gas cap will represcure the gas cap and maintain the pressure during the subsequent production life rather than depend exclusively on gas expansion to lower pressure."

Page 19 - "The reported average recovery from such reservoirs is of the order of 44 percent."

Rebuttal Comments:

Dr. Doscher's statement in his testimony that had found no field evidence of low saturations for field lives of the order of 25 years is not consistent with his discussions in his report on the Hawkins, Venezuelan and twenty Texas fields. He cites values of 3 or 5 percent for pressure cores for the Hawkins Field and states that volumetric results are impressively different. Not discussed by Dr. Doscher is that fact that Hawkins results are based on 1969 conditions when the field life was 28 years - quite similar to that for Prudhoe Bay.

The few field cases in his report reveal an incomplete or superficial survey of the literature. Fields discussed in the recent literature are Hawkins;[15,16,17,18] LL-370 area, Bolivar Coastal Field, Venezuela;[18] Mile Six Pool, Peru;[19] Elk Basin, Wyoming;[20] Grieve Unit, Wyoming;[21] and Coalinga Nose Field, California.[22] Recovery efficiencies and residual oil saturations and the approximate field lives at the time of the observation are shown in the table below:

GRAVITY DRAINAGE RECOVERIES OBSERVED IN ACTUAL FIELDS

Field	Observed Recovery %OOIP	Observed Average Residual Oil Saturation %Pore Vol.	Project Life At Time Of Observation Years
Hawkins, Texas	87	12	28
LL-370, BCF, Vz.	69	27	7
Mile Six, Peru	67	23	20
Elk Basin, Wyoming	66	31	11
Grieve Unit, Wyoming	60	37	25
Coalinga Nose, Calif.	47	39	22
Projected For Prudhoe Bay	65	28	20

Dr. Doscher's attempt to rationalize the lack of relevance of Hawkins performance to Prudhoe Bay by citing a seventeenfold lower permeability is inaccurate. Firstly, the average vertical permeability at Hawkins was about 2,377 md. Secondly, the harmonic average vertical permeability at Prudhoe Bay averages 61 md or thirty-ninefold less than Hawkins. The oil viscosities in the regions just under the original gas caps were 2.0 and 0.5 cp at Hawkins and Prudhoe Bay, respectively. Thus, the mobilities in oil saturated regions were 2.377/2.0 or 1.19 Darcy's/cp at Hawkins and 0.061/0.5 or 0.122 Darcy's/cp for Prudhoe Bay, a tenfold difference in mobility to oil in oil saturated regions. This difference in oil mobility alone would suggest a less favorable gravity drainage for Prudhoe Bay than for Hawkins. In addition, comparison of gas-oil relative permeability data for Hawkins[13] with those for Prudhoe Bay reveals that the Prudhoe Bay oil saturations are significantly higher than those for Hawkins for low relative permeabilities to oil. Thus, the average residual oil saturations up 28 percent in the gas-invaded regions of the Prudhoe Bay Field result from both its unfavorable relative permeability characteristics and its lower vertical mobility to oil compared to Hawkins. Average oil saturation of 28 percent in gas-invaded regions of the Prudhoe Bay simulator are not surprising or unusual compared to data from other fields.

Another misconception present in Dr. Doscher's report is the implication that the Hawkins gas injection project was primarily to maintain pressure to prevent shrinkage losses or viscosity increases. The facts are that shrinkage losses and effects of viscosity increases are relatively small. The facts as stated in four recent Railroad Commission hearings and described in four technical papers[17,18,19,20] that gas drive is significantly better than water drive at Hawkins, 87 percent versus 42 percent observed recoveries at breakthrough. The purpose of pressurizing the reservoir to 1,700 psi (original pressure was 1,985 psi) is to build pressure in the oil zone up to that of the aquifer, thereby preventing additional water influx. Substituting a more efficient gas driven-gravity drainage mechanism for a less efficient natural water drive is responsible for most of the 189 MMSTB increase in recovery expected at Hawkins.

The operators' strategy at Prudhoe Bay is the same as that for Hawkins, that is to use the most efficient drive in the various regions of the reservoir, not just to help maintain pressure by injecting gas or water.

(f) Dr. Doscher testified that the sale of gas from the Prudhoe Bay Field could result in the loss of oil reserves due to oil moving into the gas cap. There is no danger of this occurring with proper operating plans.

Doscher Testimony October 12, 1977:

Page 348, Line 14 - Question by Senator Bartlett - "Is there any chance in the plan proposed by the operators that the gas cap pressure will be reduced to the extent that the oil migration in the column into the gas cap. . .."

Dr. Doscher's response - "Oh, yes. There is great danger of this, and the operator's plan to compensate for this by essentially dumping water into the gas cap. . ."

Rebuttal Comments:

Model studies show that there is very little chance that oil will migrate into the gas cap at Prudhoe Bay. During the first few years of production, the gas oil contact will move down vertically about 25 feet per year. Since solution gas will be reinjected until the gas pipeline is available, the total gas in the gas cap will increase by about 0.3 Tcf/year. In addition, solution gas evolved within the reservoir will migrate to the cap once the critical gas saturation of about 3 percent is reached. Thus, when gas sales begin 6 to 7 years from now, the gas-oil contact will be 150 feet or so below its original position. This "cushion" of solution gas reinjected or evolved within the reservoir means that gas cap gas voidage will be delayed well beyond 10 years when a major fraction of the oil reserve will have been recovered.

The surveillance plan for neutron logging to track movement of the gas-oil contact provides further assurance that no oil will invade the original gas cap.

Model sensitivity runs with water injection into the cap were made to investigate potential improvements in oil recovery by sweeping more of the interior with gas. Thus, Dr. Doscher's assumption of the reasons for the operator's plan to "dump" water into the gas cap is not correct.

2. The opportunity for tertiary recovery operations could be missed resulting in the loss of additional 4 billion barrels of oil.

There is a great deal of conversation in the report by Dr. Doscher and Dr. Dougherty regarding the use of CO_2 to increase oil reserves by 4 billion barrels. There are statements in the report that the State and operators should have considered this possibility. As will be discussed, the operators have considered the use of CO_2 for miscible displacement and learned very early that it would not work because the original reservoir pressure is well below that required for CO_2 to be miscible with the oil. It is surprising that Dr. Doscher did not check readily available literature regarding CO_2 miscibility before making such statements and even more surprising he did not ask the operators about it during his meetings with them during June and July, 1977.

Following are some of the statements made regarding the use of tertiary recovery techniques at Prudhoe Bay and comments regarding analyses made by Exxon on tertiary recovery potential for Prudhoe Bay.

(a) Statements from Doscher's Report

Page 53 - "If such miscibility of carbon dioxide with Prudhoe Bay crude can be demonstrated, then significant recovery of the residual oil from the Prudhoe Bay Field is conceivable. ....Produced crude oil could be burned to produce carbon dioxide. ... The ultimate value of a delivered barrel of Prudhoe Bay crude may be so much greater than its on-site value (it already is so), that the cost of burning 2 billion barrels of the 6 that might be produced by such a scheme would be more than offset by the 4 billion barrels of saleable crude."

Rebuttal Comments:

Carbon dioxide flooding at Prudhoe Bay is not practical because CO_2 is not miscible with the oil at original reservoir pressure. In fact, pressure of over 5,000 psi would be required for miscibility as noted in a 1971 publication.[23] Further, burning 2 billion barrels of crude oil produced from Prudhoe Bay during its early life to generate CO_2 is patently ridiculous. Even if CO_2 were miscible, its effectiveness would require early placement of a bank of CO_2 (on the order of 20 percent of pore volume) across the gas-oil contact; for example, during a 10-year period, this would require burning 548,000 STB/Day of crude oil. More than 36 percent of the oil produced during peak years and a growing fraction of the oil after production begins to decline would be diverted from the pipeline to the burning project.

The practicality of generating CO_2 for injection by burning oil is doubted because of difficulties in filtering soot and smoke from the gases sufficiently well so as not to plug the injection wells. Even if CO_2 were miscible with Prudhoe Bay oil, which it is not, the configuration of the oil zone and the overlying gas cap would make the efficient use of a CO_2 bank difficult if not impossible at Prudhoe Bay. A large fraction of the oil zone is overlain by thick gas sands in vertical communication with the oil zone. Bank placement would require complete displacement of this gas cap gas from the region above the oil zone. Our field experience with cycling operations suggests that such an operation is relatively inefficient with breakthrough of the injected gas commonly being at 30-percent pore volume and sweep efficiencies at 1.5 pore volumes commonly being 85 percent or less. Thus, complete displacement of the gas cap gas by CO_2 would be unlikely. Further, dilution of CO_2 by methane increases pressures required for miscibility.

We conclude that little additional recovery would be realized from injecting CO_2 at Prudhoe Bay and that 2 billion barrels of reserves would be wasted and lost by burning crude oil to generate CO_2, let alone the massive investment to implement such a project.

Further studies cited by ARCO have shown that miscibility can be achieved by adding LPG to CO_2. However, the bank placement problem and the impractically large volumes of CO_2 and LPG required for the oil zone rule out its use for the main oil zone. The possibility exists that a process using CO_2 extracted from the produced gas with enough LPG added to generate miscibility could be used in the lower very shaly portion of the reservoir, but the overall impact on recovery would be miniscule.

(b) Statements from Doscher's Report

Page 6 - "The state, should on its own if necessary, but preferably in conjunction with the operators and the Federal Government embark on an intensive research and development program to ascertain the feasibility and applicability of a tertiary recovery program for the Sadlerochit reservoir."

Rebuttal Comments:

The operators have maintained large research programs on tertiary recovery process and have conducted hundreds of field tests of various methods during the last twenty years. The process of miscible flooding with CO_2 is well known, has been the subject of many papers,[24,25,26,27] and has been tried in several pilot tests. Several large scale projects are under way in full-field applications. The operators have the competence and technology to evaluate any applicability of CO_2 to Prudhoe Bay.

Likewise, considerable research and field testing are being made on surfactant systems. We do not know of a surfactant system which will work for Prudhoe Bay conditions. The high temperatures at Prudhoe Bay cause both surfactants and polymers to deteriorate chemically and lose effectiveness with time. Whether additional research studies can find chemicals or methods of coping with temperatures of the order of 200°F, only time will tell.

3. The gas could be shipped through TAPS with the oil when oil rates decline.

Drs. Doscher and Dougherty have suggested that the Trans Alaska Pipeline System could possibly be used to transport both oil and gas. Under questioning by Senator Stevens at the recent Energy Committee hearings, Dr. Doscher stated that he did not know of any place in the world it was being done, that he did not know of any computer studies that showed it was feasible, or that he had not made any of his own computer analyses.

Recent analyses conducted in conjunction with Exxon Pipeline Company provide technical verfication for what has been known for a long time, i.e. TAPS cannot by any stretch of the imagination be used efficiently for two-phase flow of oil and gas.

(a) Statements from Doscher's Report

Page 51 - In the absence of future discoveries of crude oil which can be transported by the present crude oil line from the North Slope to Valdez, throughput will begin to decrease precipitously within eight years and within fifteen will be less than 500,000 barrels a day. It may be possible at that time to use the crude oil line for two-phase flow of oil and gas. Ultimately, some of the gas could be liquefied and transported to West Coast destinations by tankers.

Rebuttal Comments:

The report statement is very pessimistic regarding oil production and seems to assume there is no potential for the economic development of other known oil bearing formations such as the Kupurak and Lisburne. It must also assume there is no potential for discovering additional oil reserves on the North Slope or in the Beaufort Sea.

Regardless of the potential for additional oil reserves, the proposal for two-phase flow through TAPS is not sound. A detailed report on the problems associated with two-phase flow through TAPS is included as Attachment B.

4. The Prudhoe Bay gas is not needed in the lower 48.

In the report, Drs. Doscher and Dougherty question whether the sales of gas to the lower 48 states is in the best overall interests of the State and the nation.

Doscher Testimony October 25, 1977

Page 428, Line 10 - "The nation would be little the worse for not having the Prudhoe Bay gas available for immediate burning. It will amount to less than 5 percent of our current consumption."

Rebuttal Comments:

It is abundantly clear that this nation faces a current and growing shortage of natural gas and to indicate that 2.0 billion cubic feet per day of Prudhoe Bay gas is not needed is contrary to the national interest. Two BCF/D of Prudhoe Bay gas supplies the energy equivalent of about 375,000 barrels oil per day. Also, Prudhoe Bay gas reserves account for 12% of the remaining proven domestic gas reserves. The 2.0 Bcf/D of gas pipeline deliveries planned from Prudhoe Bay is equivalent to the total daily estimated consumption in all 17 states having members on the Senate Energy Committee.

5. Other statements in the report by Dr. Doscher and Dr. Dougherty bear commenting on.

(a) Statements from Doscher's Report

Page 21 - "It appears from the limited data made available to us that a major fraction of the water to be injected would be injected into the gas cap where it would serve primarily to retard the rate of pressure reduction."

Rebuttal Comments:

In none of the cases presented to the State at the May 5, 1977 hearing in Anchorage nor in the June 16, 1977 meeting in San Francisco with Dr. Doscher and Dr. Dougherty was a major fraction of the water injected into the gas cap. Maximum injection rates in the gas cap were 1 million B/D of water out of a total of 2.5 to 3.5 million B/D into the reservoir.

The volume and location of water injection has been systematically varied in the model studies so that an understanding of how to use water most efficiently to maximize oil recovery can be developed. These studies show that most efficient use of water is in the lower one-third of the reservoir where an additional oil recovery of 1 barrel per 10 barrels of water injected is realized. Injection of water into the gas cap is not too efficient, increasing oil recovery 1 barrel oil per 30 barrels of water injected. These types of ongoing studies will be repeated as a better reservoir description is developed through drilling, logging, coring and testing additional wells and by observing and matching early reservoir behavior with simulators. In this way, an optimum injection program can be developed so that gas invades those parts of the reservoir where it is more efficient than water and water flushes those regions where it is better than gas in displacing oil.

(b) Statements from Doscher's Report

Page 22 - "Prudent analysis of alternative producing schemes would in our experience have required a thorough technical and economic comparison of early implementation of a waterflood to an extent sufficient to approach complete pressure maintenance and of total reinjection of produced gas without any injection of water other than that produced from the reservoir. These would have served as references for the evaluation of all other plans. Although these may have been studied by the operators for their own use the results of such analyses were not presented to the State."

Rebuttal Comments:

At the May, 1977 State of Alaska Field Rules hearings, Exxon, in response to a question, testified that a case with water injection at the start of oil production with no gas sales whatsoever indicated a recovery only 1 percent higher than with 2 Bcf/D gas sales after 5 years and water injection after 7 years. It was also pointed out that this would be impractical in operations because "time will be required to make responsible decisions regarding waterflooding." In short the analysis has been presented to the State.

(c) Statements from Doscher's Report

Page 25 - "Surprising that neither State nor operators sought to use published technique for measuring vertical permeability in-situ."

Rebuttal Comments:

While this statement is in his report, Dr. Doscher never inquired on this subject during meetings with the producers in June and July. Had he done so, he would have learned that ARCO and Exxon conducted two in-situ vertical permeability tests in the early 1970's.

(d) Doscher testimony October 12, 1977:

Page 315, Line 15 - "I think the evidence given, the testimony given at the May hearings in Anchorage would suggest that it is now closer to eight (billion barrels of oil reserves)."

Rebuttal Comments:

Testimony was presented at the State of Alaska Field Rules Hearings which stated estimated reserves for the Prudhoe Bay Field. "Overall, the reservoir management studies indicate that oil recovery of about 40 percent can be achieved from the Main Area Sadlerochit Reservoir. Including reserves from the Eileen Area, other Permo-Triassic Formations, and gas liquids, total liquid recovery is expected to be approximately 9.8 billion stock tank barrels."

REFERENCES TO ATTACHMENT A

1. Hassler, G. L. and Brunner, E., Deahl, T. J., "The Role of Capillarity in Oil Production", Trans. AIME 155 (1944), 155.

2. Welge, H. J., "A Simplified Method for Computing Oil Recovery by Gas or Water Drive", Trans. AIME 195 (1952), 91.

3. Richardson, J. G., Kerver, J. K., Hafford, J.A., and Osoba, J.S., "Laboratory Determination of Relative Permeability", Trans. AIME 195 (1952), 187.

4. Rapoport, L.A. and Leas, W.J., "Properties of Linear Waterfloods", Trnas. AIME 198 (1953), 130.

5. Morse, R.A., Terwilliger, P.L., and Yuster, S.T., The Oil and Gas Journal, August 23, 1947, 109.

6. Osoba, J.S., Richardson, J.G., Kerver, J.K., Hafford, J.A., and Blair, P.M., "Laboratory Measurement of Relative Permeability", Trans. AIME 192 (1951), 47.

7. Geffen, T.M., Ownes, W.W., Parish, D.R., and Morse, R.A. "Experimental Investigation of Factors Affecting Laboratory Relative Permeability Measurements", Trans. AIME 192 (1951), 99.

8. Perkins, F.M., Jr. "Investigation of the Role of Capillary Forces in Laboratory Water Floods", Trans. AIME 210 (1957), 409.

9. Richardson, J.G., Perkins, F.M., Jr., and Osoba, J.S., "Differences in Fresh and Aged East Texas Woodbine Cores", Trans. AIME 204 (1955), 86.

10. Slobod, R.L., Chambers, A., Prehn, W.L., Jr., "Use of Centrifuge for Determining Connate Water, Residual Oil and Capillary Pressure Curves of Small Core Samples", Trans. AIME 192 (1951), 127.

11. Cardwell, W.T., Jr., and Parsons, R.L., "Gravity Drainage Theory", Trans. AIME 179 (1949), 199.

12. Hall, H.N., "Predicting Gravity Drainage Performance Using a Three-Dimensional Model", Trans. AIME 243 (1968), 517.

13. Richardson, J.G. and Blackwell, R.J., "Use of Simple Mathematical Models to Predict Reservoir Behavior", Trans. AIME 251 (1971), 1145.

14. Arps, J.J. and Roberts, T.G., "Effect of Relative Permeability Ratio, Oil Gravity, and Solution Gas-Oil Ratio on Primary Recovery from Depletion Type Reservoir", Trans. AIME 204 (1955), 120.

15. King, R.L., Stiles, J.H., Jr., and Waggoner, J.M., "A Reservoir Study of the Hawkins Woodbine Field", SPE 2972 presented at SPE Fall Meeting, Houston, Oct. 4-7, 1970.

16. King, R.L. and Lee, W.J., "An Engineering Study of the Hawkins Woodbine Field", JPT, Feb. 1976, 123.

17. Lee, W.J., Henry, A.J., Frank, R.D., and Neff, H.O., "A Mathematical Model of the Hawkins Woodbine Reservoir", SPE 5527 Presented at Fall SPE Meeting, Dallas, Sept. 28-Oct. 1, 1975.

18. Joslin, W.J., "Applying the Frontal Advances Equation to Vertical Segregation Reservoirs", JPT, Jan. 1964, 87.

19. Anders, E.L., Jr., "Mile Six Pool - An Evaluation of recovery EFficiency", Trans. AIME 198 (1953), 279.

20. Stewart, F.M., Garthwait, D.L., and Kebrill, F.K., "Pressure Maintenance by Inert Gas Injection in the High Relief Elk Basin Field", Trans. AIME 204 (1955), 49.

21. Hurd, J.D., "Grieve Unit - High Recovery Muddy Sand", SPE 2905 Presented at Rocky Mountain Regional Meeting, Casper, Wyo., June 8-9, 1970.

22. Van Wingan, R., Barton, W.C., Jr., and Case, C.H., "Coalinga Nose Pressure Maintenance Project", SPE 4183, Presented at California Regional Meeting, Bakersfield, California, Nov. 8-9, 1972.

23. Rathmell, J.J., Stalkup, F.I., and Hassinger, R.C., "A Laboratory Investigation of miscible Displacement by Carbon Dioxide", presented at Fall Meeting of the Society of Petroleum Engineers' of AIME, New Orleans, Louisiana.

24. Saxon, J., Jr., Breston, J.N. and Macfarlane, R.M., "Laboratory Tests with Carbon Dioxide and Carbonated Water as Flooding Mediums", Prod. Monthly, (Nov. 1951) 8.

25. Beeson, D.M. and Ortloff, G.D., "Laboratory Investigation of the Water-Driven Carbon Dioxide Process for Oil Recovery", Trans. AIME (1959), 216, 388.

26. Holm, L.W. and O'Brien, L.J., "Carbon Dioxide Test at the Med-Strawn Field", J. Pet. Tech. (April 1971) 431.

27. Holm, L.W., "Carbon Dioxide Solvent Flooding for Increased Oil Recovery", Trans. AIME (1959), 216, 225.

FIGURE 1

OIL-WATER RELATIVE PERMEABILITY

Pseudo-Reservoir Conditions in Centrifuge

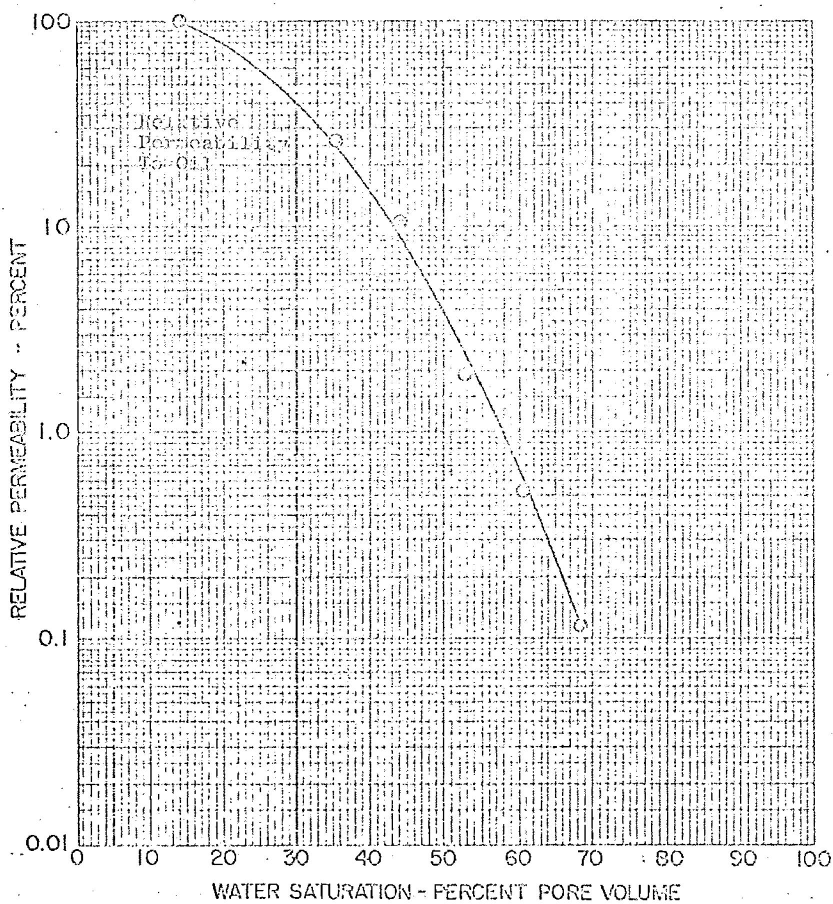


FIGURE 2

OIL-WATER RELATIVE PERMEABILITY

Reservoir Conditions Waterflood

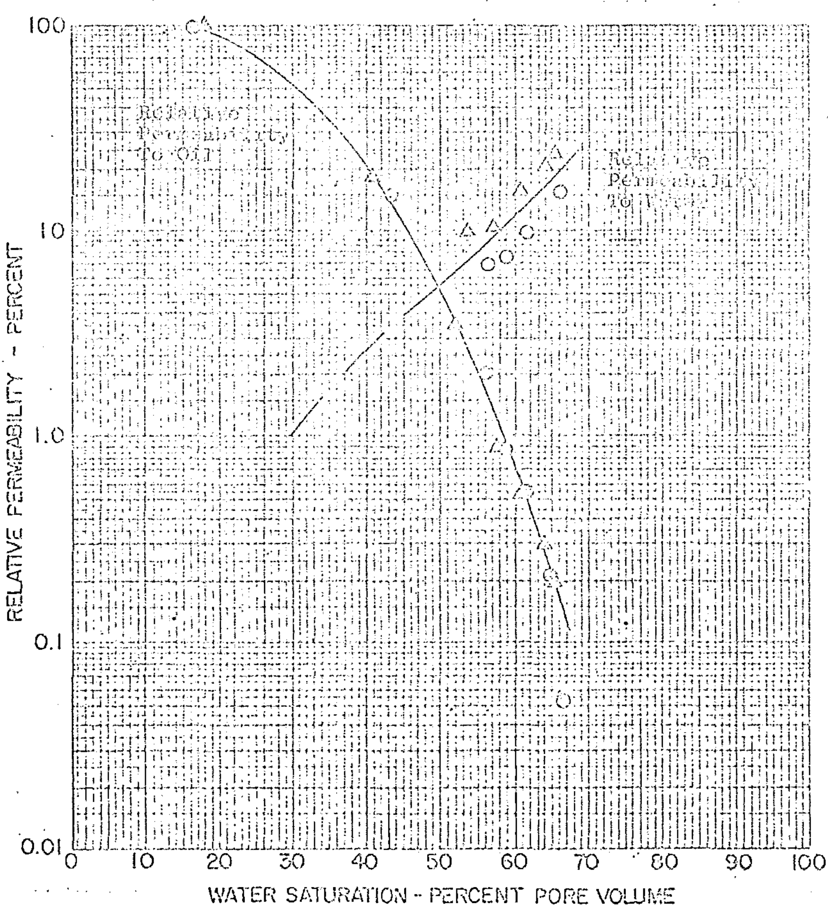


Figure 3

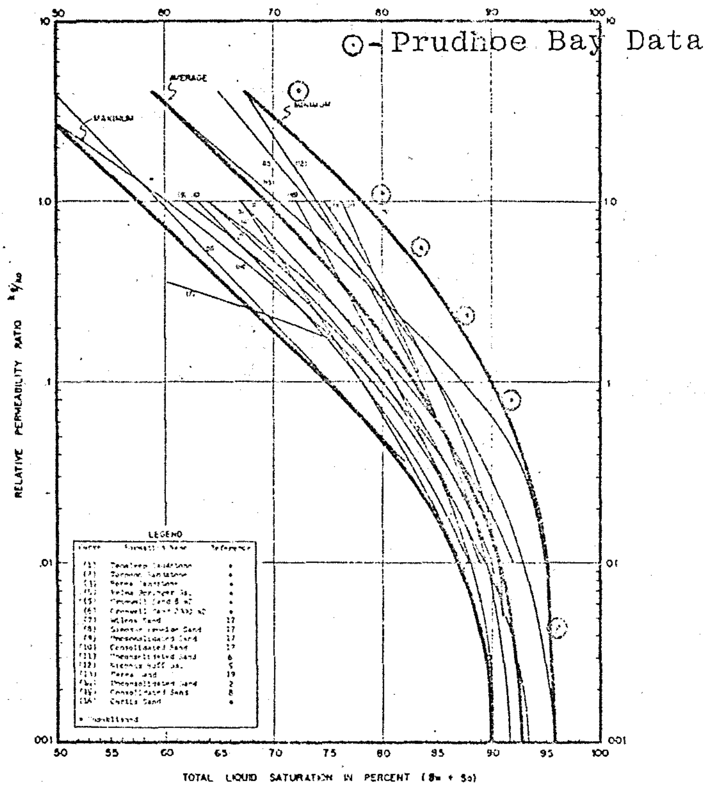


FIG. 1 — RELATIVE PERMEABILITY RATIO FOR SANDS AND SANDSTONES VS TOTAL LIQUID SATURATION.

From Arps, J.J., Trans. AIME 204 (1955), 120

ATTACHMENT B

TECHNICAL AND OTHER CONSIDERATIONS
USE OF TAPS FOR TWO-PHASE TRANSPORTATION OF OIL AND GAS

Summary

Subsequent to the October 25, 1977 hearing before the Senate Energy and Natural Resource Committee, a rather detailed feasibility study was made to reconfirm that it is not feasible to use the Trans Alaska Pipeline system for transporting oil and gas simultaneously. This study of two-phase flow was made by research scientists and engineers with the aid of high-speed computer technology. First, it was assumed that no modification was made to the system. With this assumption, it was concluded that the pipeline will not transport oil and gas at any rate because of pressure requirements that exceed the design pressure of the pipeline. Secondly, it was assumed that costs were not a restriction in modifying the pipeline for two-phase flow. With extensive modifications, that would include at least doubling the current number of pump stations, the pipeline could only transport 200 to 300 MMcf per day of gas when the line is moving 300,000 to 500,000 barrels per day of oil. After such impractical modifications, the pipeline operation would be hazardous because of dangerous vibrations, that could cause mechanical failure, resulting from slug flow of oil and gas through some 420 miles of elevated line.

Background

Recently, Dr. T. M. Doscher suggested in a report to the Legislative Affairs Agency of the State of Alaska that the Trans Alaska Pipeline System could possibly be used to transport both oil and gas. Dr. Doscher said: "In the absence of future discoveries of crude oil which can be transported by the present crude oil line from the North Slope to Valdez, throughput will begin to decline precipitously within 8 years and within 15 years will be less than 500,000 barrels per day. It may be possible at that time to use the crude oil line for two-phase flow of oil and gas. Ultimately, some of the gas could be liquefied and transported to West Coast destinations by tankers."

First, this statement is pessimistic as to oil production. The decline to the projected rate of 500,000 barrels per day may not occur for 20 years from the Prudhoe Bay Permo-Triassic reservoir alone. Considering possible economic development of other oil-bearing formations, such as the Lisburne and Kuparuk that are already known to exist, the decline in throughput may not reach 500,000 barrels per day for over 20 years. With new discoveries, TAPS throughput may not diminish to 500,000 barrels per day until after the end of the century. However, disregarding the sombrous statement of future oil production possibilities for the North Slope of Alaska, the statement that TAPS has possibility for two-phase flow of oil and gas, although appealing in nature to a layman, would be a miscreant proposition if advanced by one learned in the art and science of pipeline technology.

Although scientists and engineers have been interested in and have studied two-phase flow in pipelines for decades, the complexity and severe limitations on the use of such systems have long been accepted facts. For example, as cited in an article by Beggs and Brill, Journal of Petroleum Technology, May 1973, "The two-phase flow problem is complicated by such phenomena as slippage between phases, change of flow pattern, and mass transfer between phases. The gas liquid interface may be smooth or wavy and energy may be transferred between phases. These factors result in a much greater pressure loss than can be explained by the reduced area available to flow for each phase. When angle of flow is added to such variables as fluid properties, flow rates, and pipe diameter, the problem is indeed formidable."

The flow of two phases in a pipeline is normally used or tolerated only for relatively short distances and special circumstances such as for offshore or field gathering lines. In these situations, there are no intermediate points of compression for the gas and pressure boosts for the oil. Figure 1 shows some examples of large two-phase pipeline systems. It may be noted that there is no intermediate gas compression on these lines.

If it is assumed that two-phase flow would be handled through TAPS, regardless of cost, more intermediate pump and compressor stations would have to be added. The entire system would have to be redesigned and expanded. This would allow separation of the oil and gas at each pump station. The gas would have to be compressed and the oil would have to be pumped to higher pressures at each pump station, and the separate oil and gas streams would have to be reinjected into the pipeline. Also, the existing oil-storage system at Valdez would have to be redesigned and expanded to allow separation of the oil and gas at Valdez. Even if these modifications to the oil line were made, operating pressure, two-phase flow, and other limitations are such that only 10 to 15 percent of the 2.0 Bcf/D of available gas at Prudhoe Bay could be transported through the line if there is as much as 500,000 barrels per day of oil moving through TAPS. Depending on TAPS for movement of gas would be tantamount to taking Prudhoe Bay gas off the market until near the end of the century. Thereafter, the gas could only be moved in small quantities and with unacceptable efficiency.

In short, after many decades of pipeline transportation technology, there are no known long-distance, two-phase transportation systems in existence as proposed. Such a system may sound meritorious, but from both scientific and practical standpoints, such a system for Prudhoe Bay has no merit as an alternate to the proven transportation modes of gas pipelines for gas and oil pipelines for oil.

Although the proposed use of TAPS for two-phase flow of oil and gas can be ruled out by any expert in pipeline technology, the following discussions were developed to more fully describe the unique nature of TAPS and the reasons why TAPS is not acceptable for two-phase flow. Since the Senate Energy hearing of October 25, skilled research scientists and engineers have used their combined talents with the aid of high-speed computer technology to demonstrate the infeasibility of using TAPS for the simultaneous transportation of oil and gas.

Description of the Trans Alaska Pipeline

The Trans Alaska Pipeline starts at Prudhoe Bay and goes south along the Sagavanirtok and Atigun Rivers. It rises from slightly above sea level at the origin and crosses the Continental Divide at 4,800 feet elevation in the Atigun Pass in the Brooks Range, then descends in the Dietrich and Koyukuk River valleys and continues south across the Yukon flats. The line crosses the Yukon River, supported by the highway bridge, thence into very rugged, hilly terrain, emerging near Fairbanks and proceeding south generally following the Richardson Highway. The Alaska mountain range is crossed at an elevation of 3,300 feet in Isabel Pass. Then the line descends across Copper Valley and climbs again to 2,800 feet to cross the Chugach mountains in Thompson Pass near the terminus at Valdez. A profile of the pipeline, Figure 2, illustrates the numerous and drastic changes in elevation. Also shown are hydraulic gradients due to friction losses when transporting oil only.

The line is 48 inches in diameter and 800 miles long, with 420 miles above ground on support bents. The pipe design pressure ranges from 830 psi to 1,180 psi to meet the specific requirements of pumping crude oil at planned rates using the selected station sites.

The 12 planned pump station locations and pipe working pressures provide for a future capacity of 2 million barrels per day. Pumping equipment is initially to be installed at only 8 stations for an initial capacity of 1,200,000 barrels per day. Pressure control and line-drainage facilities are provided at station location No. 5 due to the large elevation differences descending from the Brooks Range. Oil-storage tankage is provided at the initial pump station and Valdez. At intermediate pump stations, tankage is only provided to accept line drainage and relief valve discharge.

The Trans Alaska Pipeline is designed, constructed, and operated in compliance with U.S. Department of Transportation (DOT) CFR Title 49, Part 195, "Minimum Federal Safety Standards for Liquid Pipelines" and stipulations prepared specifically for the Trans Alaska Pipeline. Conversion to natural gas would require that the pipeline system be requalified under DOT CFR Title 49, Part 192, "Minimum Federal Safety Standards for Gas Lines." However, neither of these safety standards were intended to be used for the design, construction, and operation of a large two-phase pipeline system. Conversion of the Trans Alaska Pipeline system to two-phase operation would require development of new federal safety standards and stipulations. This would be very difficult because of the lack of engineering and operating experience.

Gas Throughput Capabilities - TAPS

Gas Throughput with Existing Facilities - Based upon computer simulations and operational considerations, the Trans Alaska Pipeline, as it exists now, is incapable of transporting any gas for two primary reasons:

(1) The turbine pumps now on line will be wrecked by unbalanced forces if gas enters the pumps.

(2) The number and locations of present pump stations are inadequate for moving oil and gas at any rate; calculations indicate the line will vapor lock between stations. This is true even though pump discharge pressure is driven up to the maximum working pressure of the pipe. This vapor locking or manometer effect is caused by a loss of siphon on the downstream side of each of a succession of hills.

Gas Throughput with Modifications

Injection of even moderate quantities of natural gas along with the crude oil would significantly change the pipeline operating pressures and result in loss of pipeline capacity. Major changes in facilities and operating procedures would be required to safely transport a mixture of natural gas and crude oil. The feasibility of such an operation on the scale proposed has never been demonstrated. The efficiency of such a system is so low that economic and technical comparisons have favored separate pipelines for the two streams. Only in special cases involving short lines has two-phase operation been utilized.

Assuming that necessary gas-oil separation, compression, and pumping facilities were available to convert the line to two-phase flow, pressure and velocity constraints limit the amount of gas that can be transmitted with oil in the TAPS line to 200 to 300 MMcf per day. This conclusion was reached after conducting a computer study on ductile fracture propagation and calculating gas velocity in two-phase flow. Velocity constraints were required to prevent erosion of the pipeline steel and were computed from standard engineering design practices.

When operated as a two-phase line, the maximum permissible working pressure in the line must be reduced to about 400 psi to avoid propagating ductile fractures in the pipeline steel that was designed for oil service, not gas service, under Arctic temperature conditions.

This relatively low pressure (several hundred psi less than the minimum pressure tolerated in most gas trunklines) means that gas velocities in the line will be very high for any substantial gas flow rate since gas occupies large volumes at low pressures. Gas flow rate must be restricted to less than 30 feet per second so that erosion velocities are not exceeded. Also, the tolerable differential pressure between pump stations is about 200 psi. Therefore, assuming a working pressure of 400 psi and a suction pressure before each booster station on the line of 200 psi, maximum gas throughput for a line carrying 300,000 to 500,000 barrels of oil per day would be only 200 to 300 MMcf per day.

Thus, the velocity and pressure constraints mean that even if a very large number of flow booster stations were built, throughput of gas would be quite limited. In addition, an appreciable amount of the gas would have to be used as fuel to service compressors and pumps.

Equipment and Operating Problems and Requirements

Additional Facilities - With two-phase flow systems, facilities for separating liquid and gas before pressure boost are required at each pump station. Pipeline flow conditions over a long period of time will vary from all liquid to all gas. Thus, the gas and the liquid-handling facilities at each pump station must be designed for these two extremes. For the Alyeska pipeline to carry significant quantities of both oil and gas, separation facilities must be added at each of the 12 existing or planned pump stations. Based on rough calculations, another 12 to 15 complete and similar pump stations would have to be added to keep the line in continuous operation. Each of these stations would have oil pumps, gas compressors, separation facilities, fuel systems, electrical generators, oil relief tanks, and gas relief and flare systems.

In addition to the problems and restrictions for continuous operation of a pipeline transporting both oil and gas, there is a unique and almost impossible requirement for restarting the operation if the line is shut down for emergency or other reasons. If TAPS were transporting both oil and gas and a shut down occurred, the gas would separate and accumulate at all the high spots in the line. The restart, after such shut down, would require two to three times the normal operating pressure drops and pressure would have to be applied in about one hundred locations. An alternative would be to vent gas at some five hundred locations. It was extremely difficult to locate the present station sites and it will be almost impossible to find one hundred such sites. If the line was vented, hydrocarbon releases in the quantities required are normally not permitted by Air Quality Regulations.

Hydrates - Another operating problem is that of hydrates. Line plugging resulting from the presence of gas hydrates (ice-like solids which form when the light hydrocarbons found in gas come in contact with water) may occur at the operating temperatures and pressures of a two-phase pipeline, such as TAPS, unless preventive measures are taken. At the line pressure of 400 psia (the maximum pressure allowed if ductile fracture propagation is to be prevented), hydrates can form at any temperature below 50° F unless either (1) the water is removed from the pipeline or (2) an antifreeze, such as methanol, is injected. Removing the water from the gas can be done quite well using presently available technology (glycol contacting). However, technology does not exist which would allow sufficient drying of the crude oil. While the gas can be dried to the required 2 parts of water per million parts gas, the oil cannot be dried to the 2 ppm required to prevent hydrate formation.

If methanol is injected into the pipeline to prevent hydrate formation, approximately 300 to 600 barrels per day of methanol would be required. To supply this much methanol would require the construction of a methanol manufacturing plant on the North Slope. Prudhoe gas would have to be fractionated to provide a feedstock to the methanol plant.

Other Problems

Maximum Operating Pressure - As stated previously, the maximum pressure at which the existing TAPS line can operate as a single-phase oil line ranges from 830 to 1,180 psi. Under Arctic temperature conditions for gas service, the maximum pressure at which the existing TAPS line could operate in two-phase flow is determined by crack propagation rather than by pressure limitations of the pipe material used in the single-phase oil design. If the existing TAPS line is operated as a two-phase line, the maximum allowable pressure will be around 400 psi.

The propagation of long-running ductile fractures will not occur in the existing oil line when transporting oil only. Because liquids are relatively incompressible, the presence of a fracture in an oil pipeline rapidly reduces the internal pressure and removes the force which propagates long fractures.

<u>Vibration</u> - Intermittent slugs of oil and gas moving at a high velocity may cause mechanical failures along the 420 miles of the Trans Alaska Pipeline that is elevated. Numerous studies of two-phase flow indicate alternate slugs of gas and liquid will form under a wide range of flow conditions even though the two fluids are injected into the line continuously. Slug formation is particularly likely on uphill sections of the line. Each time a liquid slug passes through a bend, it will cause a jarring force similar to an air hammer in home water pipes. Pipe movement due to frequent slugs of liquid may cause fatigue failure in the pipe supports and will eventually wear out the teflon skids on which the elevated pipe rests. The highest slug velocity the elevated line can tolerate frequently is estimated to be 20 to 30 feet per second. This velocity restricts two-phase flow rate in the line.

FIGURE 1
SUMMARY OF OPERATING CHARACTERISTICS

TWO-PHASE PIPELINE SYSTEMS

Pipeline	Location	Owner	Diameter --inches	Length --miles	Operating Pressure-psia Inlet	Operating Pressure-psia Outlet	Gas-- MMscf/day	Liquid-- Mbbl/day	GOR-- cu.ft/bbl	Compressor Stations	Slug Catcher Size--bbl	Pigging/ Sphering Frequency
Pazanan/ Gachsaran*	Iran	OSCO	26	31	2600	1800	900	14	64,000	0	0	(a)
Marlin	Australia	Esso Australia	20	67	1600	1150	300	8	38,000	0	9,000	(a)
Zelten/Brega gas/condensate	Libya	Esso Libya	36	106	680	450	525	30	17,500	0	20,000	2 to 4 hours
Brent gas (b)	North Sea	Shell/Esso	36	280	2000	1400	1000	10	100,000	0	10,000	(a)
Brent oil (c)	North Sea	Shell/Esso and others	36	90	2000	150	110	1100	100	0	0	--
Sea Robin	Gulf of Mex.	United Gas and others	36	69	1000	650	1000	12	83,000	0	3,500	(a)
Cameron	Gulf of Mex.	Texas Eastern	24/30	112	1000	--	350	1.2	292,000	0	3,200	Daily

* Pipeline route traverses a mountainous terrain. Undulations of 100 to 200 feet occur as the line elevation rises 1500 feet from inlet to terminal.

(a) Infrequent -- generally for corrosion treatment or plant upset

(b) From Brent to Scotland. Gas-oil ratio at pipeline outlet; at inlet there is no liquid. Not yet in operation.

(c) From Cormorant to Shetland Is. Gas-oil ratio at pipeline outlet; at inlet there is no gas. Not yet in operation.

ATTACHMENT C

COMMENTS ON
GENERAL ACCOUNTING OFFICE REVIEW
OF RESERVOIR PERFORMANCE STUDIES
PRUDHOE BAY FIELD

Finding: 1. We cannot evaluate Operators and D&M due to a paucity of information contained in the reports.

Comment: A comprehensive review of the Operators' studies was presented at State of Alaska Division of Oil and Gas Conservation Pool Rule Hearings held on May 5 and 6, 1977 in Anchorage, Alaska. At that hearing, over 200 pages of direct testimony were presented supportive of the operating plan that was subsequently approved by the State. This information is a matter of the public record. A copy of Exxon's testimony is being submitted to the Senate Committee on Energy and Natural Resources.

Finding: 2. While we cannot describe the Operators and the D&M field simulations, we would conclude that of those we could, Gruy, Core, and van Poollen essentially simulate the operations of different fields although all three claim to utilize van Poollen data. We find these anamolies in the following areas:

2.a. The water drives in all three simulations are significantly different with the van Poollen simulation having the weakest aquifer and Gruy the strongest.

2.b. Both Gruy and Core only describe the Sadlerochit Field and exclude considerations of hydrocarbons located elsewhere. van Poollen posits a link between the gas cap in the Shublik formation.

2.c. Core indicates that for the same field parameters, the existence of an aquifer increases oil recoverability; van Poollen indicates the opposite, although the effect is small.

2.d. The production profiles on a yearly basis with and without aquifers are significantly different for van Poollen and Core.

2.e. Similarly oil production profiles with gas sales show that the Sadlerochit Field as simulated by van Poollen does not agree with that as simulated by Core.

Comment: It should be noted that while Core Labs and Gruy relied on van Poollen's reservoir description work, their reports indicate that they did not use all of van Poollen's data directly. Furthermore, simulation techniques and modeling of individual well performance differed between the three consultants. Thus, we believe the three consultant studies are more aptly described as being three different approaches to simulating the operations of the same field. Signficantly, they all three reach the same conclusion that the preferred plan of operation includes the sale of gas.

Finding: 2.f. We have found the estimates of oil-in-place and gas-in-place to be inconsistent among the studies and in the case of the operator study, internally inconsistent.

Comment: Following is a summary of estimated in-place volumes in the Main Area Sadlerochit reservoir as reported in the studies referenced:

	Original Oil-in-Place Stock Tank Conditions (MMMB)	Cap Gas in Place Standard Conditions TCF
Gruy	19.1	21.2
van Poollen	19.1	21.2*
Core Labs	19.5	21.2*
Operators' Report (Oct. 1976)	21.7**	22.4

*Used 26.5 Tcf in model although predicted 21.2 Tcf in Sadlerochit because of possibility of communication other reservoirs.

**Operators' Report of October 1976 reported 29.1 billion <u>reservoir</u> barrels of oil in place. Using an oil volume <u>factor of</u> 1.34 RB/STB (average of light and heavy oil/tar) this converts to 21.7 billion stock tank barrels.

There is no internal inconsistency in the Operator Study.

Finding: 2.g. We find <u>no</u> consistency, however, between the studies and the published API reserve figures as of 31 December, 1976.

Comment: The three consultants and the Operators' Report referred to oil to be produced from the Main Sadlerochit reservoir. Exxon's estimates of total liquids reserves, including reserves from the Main Area and West End Sadlerochit, other Permo-Triassic formations and gas liquids, totals 9.7 billion barrels.

Finding: 3. Despite these differences, all five studies indicate either a maximum oil recovery of about 8.4 million barrels or 42.8 percent recovery of oil-in-place.

Comment: We cannot ascertain what "five" studies are referenced. The following table summarizes recovery estimates reported in the four reports indicated:

	Main Sadlerochit Crude Oil Recovery Estimate	
	% OOIP	Billion Barrels
Gruy	43.8	8.4
van Poollen*	40.9	7.8
Core Labs	42.8	8.4
Operators' Report	40.0	8.5

*Supplement "A" dated February 1977.

It should be recognized that these results represent use of several different models and operating plans also indicated by our response to finding 2.g., recovery from other reservoirs and gas liquids must be included to determine total liquid reserves.

Finding: 4. Production of gas from Sadlerochit requires gas cap production early on in the productive life. At 2.4 Bcf a day, the capacity of the Alcan pipeline, this would require production of oil significantly above the current 1.2 million barrel a day capacity of the TAPS to avoid excessive gas cap production.

Comment: The oil production rate is expected to increase to 1.5 million barrels per day as soon as pipeline capacity is available, probably in 1980 or 1981. Gas sales from the Prudhoe Bay Field are expected to begin 6 to 7 years from now. By the time gas sales begin, over 2 Tcf of solution gas will have been reinjected and additional solution gas will have been liberated in the reservoir. For these reasons, with a gas sale of 2.0 Bcf per day beginning after 6 or 7 years, there will be no effective gas cap voidage for over 10 years.

As oil production declines and the amount of solution gas production decreases, the fraction of the sale resulting from gas cap gas production will increase.

Finding: 5. All studies agree without gas reinjection, and some type of water repressuring, there would be significant deterioration in the recovery of oil and gas.

Commenz: The significance and purpose of this finding is unclear. Exxon has not, and as far as we know, none of the other studies has investigated a plan where gas was not reinjected prior to sales. The finding is certainly not based on the reported studies and is, therefore, incorrect.

Finding: 6. We find that none of the studies addressed natural gas liquids which at 1.45 gal/Mcf of gas and 2.4 Bcf per day pipeline throughput results in almost 100,000 barrels a day of n.g.l.

Comment: The simulation models consider "crude oil" and "gas" as they exist in the Main Area Sadlerochit reservoir. Condensate and natural gas liquids result from the conversion of a certain portion of the gases to liquids in the surface facilities. Our operating plan studies certainly include such liquids.

Initial condensate yield is about 35 barrels per million cubic feet at the field separators. The amount of natural gas liquids extracted will depend upon final gas pipeline specifications, but we estimate rates of 30 to 40 thousand barrels per day at a sales rate of 2.0 Bcf/D with ultimate recovery of 300 to 400 million barrels. It is important to realize that transportation of these liquids requires blending with crude and gas sales delay would reduce the amount of gas liquids which could be transported.

Finding: 7. We find that the production profiles in the van Poollen and Core studies are markedly different. (Note: The attached graph shows the amount that oil production is likely to increase or decrease in a given year with 2.0 billion cubic feet of gas sales per day for van Poollen and 2.4 Bcf/D for Core.)

Comment: The profiles presented by GAO suggest that the latest van Poollen studies (Supplement A - February 1977) were not included in the review. van Poollen concluded from these most recent studies that the proposed oil and gas offtake rates yield maximum oil recovery.

Conclusion: At this point we cannot ascertain the overall effect of gas production and sales on the ultimate recovery of oil from the Sadlerochit reservoir.

Comment: There is substantial data available in the public record on Prudhoe Bay studies by Exxon, Arco, BP Alaska, and consultants. The State of Alaska Division of Oil and Gas Conservation, the Federal Power Commission, and other State and Federal agencies who reviewed the studies were able to endorse planned gas sales from Prudhoe Bay. The apparent dilemma indicated in the GAO's conclusion was probably caused by inadequate time to acquire available data and review the studies.

ATTACHMENT D

RESPONSES TO SENATOR DURKIN'S QUESTIONS

SUBMITTED FOR THE RECORD ON OCTOBER 25, 1977
U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

1. Could you describe what is presently being done with the natural gas liquids from Prudhoe Bay?

   Answer: Approximately 1,000 barrels per day of natural gas liquids are currently being recovered. Because of the small volume, it is being combined and reinjected with the gas.

2. Will you allow an independent petroleum engineer to review your simulated computer runs? To complete new ones?

   Answer: A comprehensive review of Exxon's Prudhoe Bay studies was presented at a public hearing before the State of Alaska Oil and Gas Conservation Committee on May 5 and 6, 1977. Enclosed is a copy of that testimony as well as questions and answers which followed the prepared testimony and a copy of supplemental information which was provided to the Conservation Committee at their request following the hearing.

   Although the enclosed information should provide the Committee with adequate data for review, Exxon is willing to meet and review the reservoir studies used to develop the Prudhoe Bay operating plan provided that information or techniques considered proprietary by Exxon are protected and provided that Exxon is reasonably convinced that the person selected is appropriately qualified to perform the proposed review. Exxon considers the latter requirement necessary to prevent the type of superficial review provided by Dr. T. M. Doscher for the Legislative Affairs Agency of the State of Alaska. While Exxon agrees to cooperate with the review, no responsibility for consulting fees will be assumed by Exxon.

   Exxon has investigated a broad range of operating plans and, therefore, it is not anticipated that additional model studies would be necessary. Because Exxon's Prudhoe Bay reservoir model is quite complex, each case study requires about 2 weeks to complete, and computing costs are in the order of $10,000 and engineering manpower would have to be redirected from new project efforts. However, if the need can be justified following the review of existing studies, Exxon would be willing to carry out a limited number of additional simulation cases at its sole expense.

3. Have you completed any studies of the feasibility of gas reinjection and early implementation of a waterflood? Would you provide the Committee with these studies?

Answer: Although Dr. Doscher's report asserted that no such case was discussed at the Alaska Conservation Committee hearing, page 51 of the May 6, 1977 transcript reflects that Exxon testified as follows: "There will be time required to make responsible decisions regarding waterflooding, so we don't think it's a reasonable assumption to assume that you can begin water injection at the same time that you start up oil production. But purely for sensitivity checks, we have looked at that situation. In the case I'm referring to, we began water injection at the start-up of oil production, fully maintaining reservoir pressure. In that case there were no gas sales whatsoever. This case indicated recoveries less than 1 percent higher than if we have gas sales beginning after 5 years and water injection beginning after 7 years. So we see very little difference, actually, between the cases." Even this extreme case, which would not have been practical or good business and was only for sensitivity checking demonstrates the lack of sensitivity with respect to the approved plan of operation. The point is that no one who has actually performed reservoir studies has suggested that water injection commence simultaneously with oil production.

As indicated in our response to question No. 2, Exxon would be willing to allow an appropriate review of all studies used to develop the Prudhoe Bay operating plan.

4. The existence of low residual saturation to gas invasion appears to be a prerequisite for successful implementation of the proposed operating plan. Yet studies sponsored by the operators apparently contradict the existence of this condition. In the face of your studies, how do you justify existence of these necessary conditions?

Answer: The premise of this question is entirely in error. The operators have not sponsored studies but have rather conducted their own independent studies of reservoir performance. While the results of the studies are not identical, independent reservoir descriptions and simulation efforts all led to the same preferred operating plan for the Prudhoe Bay field. None of the studies is in any way contradictory to the approved plan of operation.

Low residual oil saturation to gas invasion is by no means a prerequisite of the approved Prudhoe Bay operating plan. This assertion, which appears on page 17 of Dr. Doscher's report and was repeated in his testimony before the Committee, is incorrect. As indicated on page 109 of the transcript of the May 5, 1977 hearing before the Alaska Oil and Gas Conservation Committee, Exxon has investigated the sensitivity of the Prudhoe Bay operating plan to reasonable variations in key reservoir description parameters. These studies indicate that the approved oil and gas offtake rates are feasible over a reasonable range in reservoir properties. Certain operational factors, in particular, the optimum timing, location, and volume of water injection may be different depending on the reservoir description. For this reason, the plan has been developed with necessary flexibility to allow positive reaction to observed performance to achieve maximum recovery of oil and gas.

5. The operator's plan relies heavily on the assumption that there is low residual oil saturations in the Sadlerochit. Yet the operators are planning a small scale test of water injection to get information on the actual residual oil saturation to water encroachment. Why is such a test necessary? If such a test disproves your assumption, and if gas reinjection is necessary to maintain pressure, what can you do to assure no loss of oil?

Answer: The thrust of the first sentence of this question is unclear, but, assuming it refers to Dr. Doscher's assertion with respect to low residual oil saturations, it can be stated that his conclusion is incorrect.

As previously discussed, the operating plan for Prudhoe Bay has been formulated with sufficient flexibility to accommodate variations in reservoir behavior. A thorough program of reservoir surveillance and testing is being undertaken to provide data in a timely manner. Plans are currently underway to conduct water injectivity tests at selected locations in the field. The primary objectives of the tests will be to determine the injectivity into various subzones under sustained injection conditions and to determine water displacement characteristics in the reservoir. This will be of particular importance in selecting the optimum locations and volumes of water injection.

There is no information which could be gained from the test which would make it desirable to continue gas reinjection longer than planned in order to maintain pressure. By the earliest possible date that gas sales can commence, over one-third of the oil reserves will have been depleted, and the gas cap will have expanded over 100 feet into the oil column. This expansion eliminates concerns that gas sales would reduce recovery due to oil migration into the original gas cap. While gas sales alone would cause a reduction in reservoir pressure, the effect on ultimate oil recovery is small and adjustments to the water injection program can offset the potentially adverse effect on oil recovery.

6. High vertical permeability is apparently another prerequisite for success of the proposed operating plan. Have you used a standard published technique for measuring in-situ vertical permeability in the vicinity of a well? Why not?

   Answer: High vertical permeability is not a prerequisite for the success of the approved operating plan for Prudhoe Bay.

   Vertical permeability in the Sadlerochit reservoir is estimated to be quite good based on extensive analyses of core data, geologic environment, and studies of the effect of minor, discontinuous shales on vertical permeability. ARCO and Exxon attempted two in-situ vertical permeability tests in the early 1970's to measure the effective vertical permeability in the vicinity of the wellbore. These tests were very costly and the results were not conclusive. Dr. Doscher's assertion on page 25 of his report that such a technique had not been used at Prudhoe Bay is incorrect.

7. How much oil will be left behind in the reservoir at the completion of production under the present production plan? What are your plans for getting this oil out through tertiary recovery?

   Answer: Based on an ultimate recovery of 40 percent of the original oil in place, the Main Sadlerochit reservoir at Prudhoe Bay would contain approximately 13 billion barrels at the completion of conventional operations. However, almost 2 billion barrels of this total would consist of heavy oil/tar at the base of the oil column.

Although Exxon maintains a considerable research effort devoted to developing viable tertiary recovery techniques, we know of no such techniques at the present time which would be applicable at Prudhoe Bay on a fieldwide basis. Several potential enhanced recovery methods have been evaluated for use at Prudhoe Bay, including miscible carbon dioxide flooding and the use of surfactant systems. Injection of pure carbon dioxide would not significantly increase recovery at Prudhoe Bay because the pressure required to achieve miscibility is significantly above original reservoir pressure. Surfactant flooding would be impractical because a suitable a chemical surfactant system which would work at Prudhoe Bay reservoir conditions is lacking.

It should be obvious that we are aware of the significant potential for tertiary recovery at Prudhoe Bay, and we will continue to examine the use of tertiary recovery techniques as research and development continue. We believe that there is a reasonable chance that a technically successful process can be developed, but it will likely require many years of study and testing. Further, it is unlikely that development and use of tertiary recovery techniques at Prudhoe Bay would be significantly impacted by the timing of gas sales.

8. How can you justify such a firm conclusion on production of 2 Bcf per day of gas when you can't reach a conclusion on when to begin water injection?

Answer: The effect of gas sales on reservoir performance is primarily a voidage or pressure effect which can be projected quite accurately based on an assessment of fluid properties. Since the Sadlerochit crude does not have high shrinkage characteristics, the effect of gas sales on oil recovery will be slight and can be offset through a properly designed waterflood.

Selection of the optimum locations and volumes of water injection is a more complex problem which will depend substantially on the relative displacement efficiency of the natural depletion mechanism compared to water displacement. Although the final selection of optimum source water injection locations and volumes will require observation of some field performance and testing, the operating plan envisions such injection within 7 years after the start of oil production provided recovery benefits are confirmed. Studies indicate that this timing is consistent with achieving maximum benefits of source water injection.

ATTACHMENT E

RESPONSE TO SENATOR HANSEN'S QUESTIONS AND TRANSCRIPT OF MR. L. G. RAWL'S TESTIMONY BEFORE THE JOINT HOUSE SUBCOMMITTEE ON OCTOBER 14, 1977

Does your company plan to assist in payment of the cost of the conditioning plant? Does your company believe that the cost of the gas conditioning plant should be borne by the gas pipeline project?

Answer: An integral part of the pipeline system under consideration is the gas conditioning facility. In addition to specifying that carbon dioxide content of the gas be reduced prior to transmission and that the gas be compressed to a high inlet pipeline pressure, the potential pipeline owners have specified several other conditioning requirements which will increase pipeline efficiency. Specifically, refrigeration facilities will be required to chill the gas so that construction savings can be realized by burying the pipeline in the permafrost. To avoid freezing of liquids in the line, the gas will have to be treated to provide an unusually low water vapor content and to maintain condensable hydrocarbon content within close tolerances.

These five conditioning steps--lowering carbon dioxide content, providing high pipeline inlet pressure, chilling, providing extremely thorough water removal, and maintaining close control of condensable hydrocarbon content--are all designed to minimize the investment and operating cost of the pipeline. Although such conditioning is costly--estimated at about 90¢/Mcf (escalated) for Prudhoe Bay gas--the expenditure should be more than offset by savings in pipeline construction and operating costs.

The point that must be kept in mind is that these conditioning facilities are an integral part of the gas transmission facilities--not the production facility. This distinction, which is not unique to Prudhoe Bay gas, has for some time been recognized by the FPC in their certification of gas sales contracts and pipeline projects.

Therefore, Exxon USA does not plan to participate in financing the conditioning plant. Moreover, we had four contracts signed for gas share back in 1975. At that time the gas companies had agreed to include the gas conditioning investment in their part of this project.

Does your company believe the gas pipeline project can be privately financed? Does your company intend to assist in financing the pipeline project by providing debt guarantees?

Answer: We are pleased that the Alcan financial advisors and a representative of the U.S. Treasury have concluded that the system can be financied without producer participation and that they have so testified before these subcommittees. However, no project of this magnitude has been financed in the private sector and hence its financeability is uncertain. Moreover, we do not know important elements of the Alcan financing plan, such as who the equity sponsors will be and what conditions will be associated with financial participation. As you are probably aware, Exxon USA is not in the interstate gas transmission business and does not plan to participate in the financing of the proposed gas transmission system in any form including debt guarantees.

Does your company believe that it may be equitable to have a gas pipeline project pay for all or part of the water flood cost?

Answer: No.

Is your company currently negotiating with any companies for the sale of your natural gas at Prudhoe Bay?

Answer: Exxon is not currently negotiating with any prospective customers because the Pipeline Project has not been approved and because of uncertainties associated with the National Energy Plan now being considered by Congress.

October 31, 1977

Attached is a copy of Mr. L. G. Rawl's testimony given before the U.S. House of Representatives Committee on Interstate and Foreign Commerce and Interior and Insular Affairs concerning the route selected by the President for transporting Alaska natural gas. This transcript has been corrected for Mr. Rawl's testimony only. No attempt has been made to verify or correct the testimony of others that appear in this transcript.

Mr. Brown, listening to the subsequent panel of producers.

Mr. Goldman. We will have people here covering it and we will thoroughly analyze the statement.

Mr. Dingell. Without objection, the record will remain open for the purpose of receiving comments referred to.

The Chair observes next is a panel of producers: Mr. L. G. Rawl, executive vice president, Exxon Company U.S.A., Post Office Box 2180, Houston, Texas; Mr. C. O. Goldsmith, vice president-Financing, Atlantic Richfield Company, 515 South Flower, Los Angeles, California; Mr. John R. Miller, vice president-Finance and Planning, The Standard Oil Company, Ohio,Midland Building, 101 Prospect Avenue, Cleveland, Ohio.

STATEMENTS OF L. G. RAWL, EXECUTIVE VICE PRESIDENT, EXXON COMPANY U.S.A., POST OFFICE BOX 2180, HOUSTON, TEXAS 77001; C. O. GOLDSMITH, VICE PRESIDENT - FINANCING, ATLANTIC RICHFIELD COMPANY, 515 SOUTH FLOWER, LOS ANGELES, CALIFORNIA 90017, ACCOMPANIED BY: KENNETH DICKERSON, COUNSEL, ATLANTIC

RICHFIELD COMPANY; AND JOHN R. MILLER, VICE PRESIDENT - FINANCE AND PLANNING, THE STANDARD OIL COMPANY (OHIO), MIDLAND BUILDING, 101 PROSPECT AVENUE, CLEVELAND, OHIO 44115

Mr. Dingell. Gentlemen, we are pleased that you are with us. If you would each, for purposes of the record, identify yourselves, commencing on your left and my right, we will be most pleased to recieve your statements.

STATEMENT OF L. G. RAWL

Mr. Rawl. Thank you, Mr. Chairman, members of the subcommittee:

I am L. G. Rawl, executive vice president, Exxon Company U.S.A.

Exxon takes no exception to the President's selection of the Alcan project. We are encouraged by the recent progress of the Governments of Canada and the United States in reaching agreement on a gas pipeline project and firmly believe that it is in the best interests of both countries to implement construction of a gas transmission system.

We are also pleased that the Alcan financial advisors and a representative of the U.S. Treasury have concluded that the system can be financed without producer participation and that they have so testified before these subcommittees. As you are probably aware, Exxon U.S.A. is not in the interstate gas transmission business and does not plan to participate in the financing of the proposed gas transmission system.

Significance.

It is important that the pipeline selection process be completed promptly and construction initiated, since U.S. gas production from known reserves is continuing to decline. Development of this frontier transportation system, in addition to allowing Prudhoe Bay gas to flow to market, will accomplish an even broader national energy objective by stimulating frontier exploration and development.

Although Prudhoe Bay contains enough gas to justify the proposed line--2.0 Bcf/D--additional production must be developed to fill the line to the ultimate 3.4 Bcf/D design capacity. Completion of the proposed line or initiation of construction will accelerate efforts to explore for and develop additional northern Alaska production which will lower pipeline tariffs by filling the pipeline to design capacity.

On an even broader basis, favorable resolution of the Prudhoe Bay gas issue will stimulate exploration and production in all U.S. frontiers. Although remaining U.S. gas potential is believed to be ~~many~~ several times known reserves, most of this potential is in frontier areas where exploration and development involves high risk, high costs, and long payouts.

In order to aggressively explore and develop frontier areas under these adversities, producers must have reason to believe that discoveries, if made, can be brought to market in a timely manner at a reasonable profit.

Mr. Dingell. Just a minute.

The Chair will observe that this is a hearing and those who desire to be present in the room are requested to assume their seats at the earliest moment and maintain the kind of quiet and decorous behavior that will help the committee to get expeditiously through its business with a full understanding of the presentation of the witnesses.

Mr. Rawl. Since the most recent frontier development is Prudhoe Bay, the government's handling of this development will be the latest industry ''data point'' for frontier analysis. Prompt approval of a transportation system and reasonable regulation will signal the industry to accelerate frontier exploration and development.

I would now like to discuss two topics that Exxon U.S.A. has been asked to address: Reserves and Gas Conditioning.

Reserves.

Numerous industry and government studies have confirmed that Prudhoe Bay reserves and expected deliverability are sufficient to justify a gas transmission system. Our estimate of total Prudhoe gas reserves is 26 Tcf; Exxon's share is about one third. The Prudhoe Bay unit operating plan, which was approved by the State of Alaska on April 1, 1977, anticipates the production of 2.7 Bcf per day, of which 2.0 Bcf per day will be available for delivery to the pipeline. Our studies indicate that total field development--over 500 additional wells and related gathering and production facilities--will be sufficient to maintain this rate for at least 20 years, thereby providing the threshold volumes required to assure project viability.

Conditioning.

An integral part of the pipeline system under consideration is the gas conditioning facility. In addition to specifying that carbon dioxide content of the gas be reduced prior to transmission and that the gas be compressed to a high inlet pipeline pressure, the potential pipeline owners have specified several other conditioning requirements which will increase pipeline efficiency.

Specifically, refrigeration facilities will be required to chill the gas so that construction savings can be realized by burying the pipeline in the permafrost. To avoid

98-069 O - 78 - 39

freezing of liquids in the line, the gas will have to be ~~crated~~ treated to provide an unusually low water vapor content and to maintain condensable hydrocarbon content within close tolerances.

These five conditioning steps--lowering carbon dioxide content, providing high pipeline inlet pressure, chilling, providing extremely thorough water removal, and maintaining close control of condensable hydrocarbon content--are all designed to minimize the investment and operating cost of the piepline. Although such conditioning is costly--estimated at about 90 cents per Mcf/(escalated) for Prudhoe Bay gas--the expenditure should be more than offset by savings in pipeline construction and operating costs.

The point that must be kept in mind is that these conditioning facilities are an integral part of the gas transmission facilities--not the production facility. This distinction, which is not unique to Prudhoe Bay gas, has for some time been recognized by the FPC in their certification of gas sales contracts and pipeline projects.

Before concluding my remarks, I would like to mention three specific items that we believe should be referred to the administration for review prior to approval of a final decision.

Pricing.

First, as we understand the Alaska Gas Transportation Act, it does not specify that pricing policy be set by this decision. However, section 6 of the decision includes the statement, and I quote, ''This decision, therefore, calls for enactment of a gas pricing approach similar to that contained in the National Energy Plan.'' The decision also imposes the condition, and again I quote, ''All contracts for sale of Alaska gas....shall be submitted for approval of the Federal Power Commission.''

Such statement and condition are not necessary or appropriate to the decision, since its purpose under the Act is to designate a pipeline system, not determine gas pricing and regulation. Such provisions could conflict with proposed legislation now being considered by Congress, and thus, create uncertainty as to the regulatory status of Alaska gas. Uncertainty in that regard could delay the completion of gas sales contracts. For these reasons, we believe that pricing policy statements should be omitted from the approved decision.

Project Description.

Second, in order to expedite the development and review of environmental impact statements, certificate applications, and other required submissions, the gas conditioning facilities, which are an integral part of the gas transmission system, should be defined as such and properly included in the definition of the pipeline system

Indemnity.

Finally, as an owner of the Trans-Alaska pipeline, Exxon is concern that the decision does not address the subject of indemnification of the oil pipeline owners against damages which might result form construction of the gas line. A similar concern is that the decision is also silent on the subject of providing security for the oil piepline during gas pipeline construction.

Conclusion.

In summary, Exxon is encouraged by progress being made toward selection of a gas transmission system for Alaskan gas; the early construction of such a pipeline is certainly in the best interests both of the United States and Canada. We are confident that existing reserves are sufficient to justify a pieline from Prudhoe Bay and believe that, given sufficient exploration incentive, future northern Alaska discoveries will be sufficient to fill the proposed line to design capacity.

Mr. Dingell. The attachment, without objection, will be placed in the record at this point.

[The attachment follows:]

********** COMMITTEE INSERT **********

Mr. Dingell. Sir, will you identify yourself, please?

STATEMENT OF CLAUDE O. GOLDSMITH

[The full statement of Claude O. Goldsmith follows:]

********** Insert 4A **********

Mr. Goldsmith. Thank you.

Mr. Chairman and members of the committee:

My name is Claude Goldsmith, and I am vice president in charge of Atlantic Richfield Company's finance and tax division.

Thank you for the opportunity to make this statement of Atlantic Richfield's views and report to Congress.

My detailed testimony has been given to the committee, and I ask that it be included in the record, but please permit me to discuss with you orally.

Mr. Dingell. The full presentation will appear in the record at this point and you are recognized for such summary and comments you desire.

Mr. Goldsmith. I would ike to discuss orally financing, gas conditioning and gas pricing.

First as to gas pricing, Atlantic Richfield's Prudhoe Bay gas reserves are currently estimated to be 7.52 Tcf. While we fully support prompt construction of an Alaskan gas transmission facility and recognize the desirability of early identification of gas purchasers, negotiation of contracts for the sale of Atlantic Richfield's gas has necessarily been deferred pending essential regulatory and legislative action clarifying the pricing of Alaskan gas.

Absent deregulation, Atlantic Richfield is in accord with the premise of the President's decision that natural gas from the State of Alaska receive the same pricing treatment afforded all other domestically produced natural gas. Until adoption by Congress or the Federal Energy Regulatory Commission of a fair and nondiscriminatory pricing formula for Alaskan gas, Atlantic Richfield cannot commence negotiations of gas sales contracts.

As we understand it, the sponsors will not commence construction.

Next is as to conditioning.

In the lower 48 States, jurisdictional sales of interstate gas of the pressure and quality available at the wellhead in the Prudhoe Bay field would be authorized by the Federal Energy Regulatory Commission at the current base national rate of $1.47 per Mcf plus an adjustment for production taxes and Btu content. At the present time these FERC regulations do not apply to Alaska.

It is our belief that the application of existing regulatory policies or the principles of the National Energy Plan to Alaskan gas will also equitably resolve the problem of providing for the ''conditioning'' of Prudhoe Bay gas to meet piepline requirements.

Significantly, it is the gas transmission system owners that will dictate the gas pressure and quality requirements at the inlet of the gas conditioning facilties. Based on a 1971 study, we estimated that the cost of gas handling and conditioning facilities could exceed $1.8 billion; however, these costs cannot be accurately determined until the pipeline design has been completed. In any event, they should be considered as part of the transportation costs, and not charged against the wellhead price as they are not charged against the wellhead price in the lower 48 States.

Let me turn now to the question of the financial analysis and conclusions of the President's decision.

The President's decision requires that the ''successful applicant shall provide for private financing of the project, and shall make the final arrangements for all debt and equity financing prior to the initiation of construction.'' The decision also specifies that:

''The successful applicant shall exclude and prohibit producers of signficant amounts of Alaskan gas or their subsidiaries and affiliates from participating in the ownership of the Alaska nautral gas transportation system, except that such producers may rpovide guarantees for project debt. The aforesaid producers of Alaskan gas may not be equity members of the sponsoring consortium, have any voting power in the project, have any role in the management or operations of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put into effect, or impose conditions on the guarantees of project debt permitted above which may give rise to competitive abuse, including power to veto pro-competitive policies.''

Such limitations are unprecedented in any financial transaction that we have ever encountered.

Atlantic Richfield does not view the prospect of financial participation in an Alaskan gas transportation system as an attractive investment opportunity for our company.

Mr. Roncalio. Understatement of the day.

Mr. Goldsmith. So we are not disturbed economically by being excluded from equity participation, but we are deeply concerned that the judgmental theorizing of the Department of Justice influenced the President's decision. To reduce the price of Alaska gas below the price of other domestically produced gas, whether by compulsory participation in financing, price regulation or the imposition of conditioning costs upon the State and producers, would constitute unprecedented dicrimination against a single State and its gas producers.

The President's decision has the announced objective of placing the risk of noncompletion on the projection sponsors, the producers and the State of Alaska, as was testified tc.

It suggests that such risk is minimal and that Alaskan producers and the State of Alaska can bear it withcut detriment and for a ''relatively small'' fee.

Addditionally, the President's decision explicitly rejects any possibility of Federal financial assistance for the project. Permit me to comment on the decision's rationale for the denial cf Federal financial assistance.

First, the decision concludes that, even though the risk of noncompletion is minimal it would be inequitable to place such risk on the taxpayers. Government guarantees of project debt would, as a practical certainty, eliminate any risk of noncompletion and it follows that such guarantees would be without cost to the taxpayers.

The second basis for denying Federal financial assistance was that the decision concluded that the government should not perform the critical risk assessment function normally performed by private lenders. This seems to me contradictory in view of the risk assessment made by the President's report which I have just outlined. In fact, the larger risks in this project are governmental in nature and cannot be resolved by private concerns.

Third, although the decision recognizes that Federal guarantees would result in lower interst rates at minimal risk and no cost to the taxpayer, such reduction however is deemed undesirable since it would yield an ''artificially low price for gas.''

Here again, we find a paradox since the policies of the Federal Power Commission under the Natural Gas Act have successfully maintained an ''artificially low price for gas'' for over 20 years and deregulation which would permit gas prices to rise above their ''artificially low'' level is opposed by the administration.

Alaska gas delivered to the lower 48 States will be costly in any event. Prior witnesses before these committees have estimated that the combination of tariff, conditioning cost and gas price could well exceed $3.40 per Mcf (1975 dollars).

By the time the gas is delivered in 1983 or thereafter the tariff is going to be considerably higher in these dollars, and many people in this country face the problem that their wages don't increase with inflation, notably retired people and congressmen.

I believe that government guarantees could lower interest costs on a projected $10 billion of debt or therefore as much a $300 million per year reduction in tariff, or a total of $6.6 billion on the average 22-year life of a 30-year bond issue. This would result in a reduction in transportation costs of 30 cents to 40 cents per million Btu for the American consumer. During the initial years when the tariff rate is at its peak, this could be particularly critical.

Fourth, it is claimed that the incentive for efficient management of the project would be reduced by Federal financial assistance. If so, the same result would flow from producer guarantees, especially since the producers would be denied the opportunity to attempt to correct moanagement deficiencies or cost overruns.

Fifth, it is claimed that the government would be in conflicting roles if it guaranteed as well as regulated the project. I doubt that Congress would permit the Federal regulatopry agencies to exercise less than optimum supervision of design, construction and operation of the system whether or not governmental guarantees were made and particularly after the testimony today.

Sixth, and finally, it is believed that providing Federal assistance to this project would set an undesirable precedent. I suggest that the uniqueness of the financial requirements of the Alaskan natural gas transportation system should refute any possibility of Federal completion guarantees being cited as a precedent. Here we have an artificial economic environment, away from the marketplace, created by government regulation of gas prices and pipeline returns and also involving a foreign government.

Our analysis indicates that over 50 percent of the total projected tariff represents the cost of money after allowance for Federal income taxes. Accordingly, if Federal completion guarantees would insure financing of the project and significantly reduce the ultimate tariff without cost to the taxpayer, I do not understand why it is not being considered.

In addition to the importance of minimizing the interest cost, we should consider the applicant's ability to obtain the debt capital required on the basis of project financing alone. Using Alcan's $9.7 billion cost, before overruns, Alcan estimates it will have to raise over $5.5 billion from U.S. institutional lenders, plus about $1 billion from U.S. banks and $1 billion from Canadian lenders.

Even without prospective overruns, the capacity of capital markets for a single project financing will be severely stretched and perhaps exceeded. Lenders provide funds only if borrowers can repay whether or not a project is completed or successful, or if lenders are assured by others who can and will pay in place of the borrowers, neither element of credit extension is currently present in the Alcan financing plan.

Regardless of the estimated degree of the nocompletion risk, the magnitude of the contemplated liability is staggering and necessarily open ended. I can state with complete assurance that, even if we were never called upon to perform, the mere presence of the required footnote to Arco's financial statements disclosing the existence of a contingent liability of such potential impact would adversely affect our bond rating and would be detrimental both to our ability to borrow money and to the rate of interest that would be required upon any borrowings that we were able to secure.

Mr. Dingell. You are talking about if you would appear as guarantors in whole or in part of the pipeline.

Mr. Goldsmith. Yes, sir.

If Atlantic Richfield were to take on completion guarantees it could, with our existing debt of $3.5 billion,

98-069 O - 78 - 40

place us in default of an existing bond indenture, and it would today, if we were called to on or such guarantees today and added to our existing $3.5 billion of debt place us in default of an existing bond indenture, trigger acceleration of roughly $1 billion of exisitng obligations and exceed the debt limits permitted by our articles of incorporation related to preferred stock.

If Atlantic Richfield were to commit its limited financial capacity to pipeline debt guarantees it would advantage our competitors, the other gas producers in Alaska and Canada, both present and future, who are not likewise compelled to guarantee project debts. Also, Atlantic Richfield's ability to fund its primary functions--oil and gas exploration, production, refining and marketing--would be signfiicantly reduced, to the detriment of the nation's energy supply and to the detriment of our shareholders.

I see no possible circumstance under which Atlantic Richfield would be able to commit its assets to the type of debt guarantees proposed to be structured under the

President's decision.

There is urgency to arriving at a viable solution since, as indicated by the testimony before these committees from the chairman of Alcan, any upfront delay will prevent delivery of Canadian gas as planned for the 1979-1980 heating season, one of the attractions of this project.

I fear that there is a substantial likelihood of delay because the sponsors may be uanble to raise the encraous sums required under a financing plan which currently lacks sufficient credit support. This project faces formidable political and regulatory risks created by governments, and it would seem appropriate that the government assist in minimizing these risks.

I have shared with you the concerns of my company regarding decisions yet to be made by the Congress and the regulatory agencies.

Now permit me to make two suggestions that are not in the submitted testimony.

I believe that major uncertainites can be promptly resolved if the Federal Energy Regulatory Commission would undertake immediate action in two areas--gas pricing and project financing.

For more than 2 years my company has urged the uniform application of nationwide regulation to all producing States, including Alaska. Our petition requesting such action is filed as an exhibit to my written statement. Pending enactment of a national energy plan, we believe that the FERC should immediately extend existing nationwide policies to Alaska so that the State of Alaska, the pipeline applicant, producers and potential gas purchasers, will be able to make economic decisions concerning their role in the production, sale and transportation of Alaskan gas.

May I suggest that Congress should be assured that Alaska is not singled out for discriminatory rate treatment.

Additionally, the FERC should determine whether or not the recommended project can be financed as currently proposed without completion guarantees by the producers or the government. If not, the FERC should promptly inform these committees so that other arrangmenets can be made.

We respectfully suggest that these committees approve the President's recommendation but require the FERC to report back to the Congress no later than 6 months from the date of its approval, to inform the Congress as to the financiability of the project and, absent legislation, the steps which the commission has taken to extend its nationwide policies to the State of Alaska. If at that time the commission has not satisfactorily resolved these issues, these committees can then determine what further steps need be taken.

Thank you for your time.

Mr. Dingell. Thank you very much.

You have given us an impressive statement, Mr. Goldsmith.

Our next panel member is Mr. Miller.

STATEMENT OF JOHN R. MILLER

[The full statement of John R. Miller follows:]

********** Insert 4B **********

Mr. Miller. My name is John R. Miller. I am vice president of Finance and Planning for The Standard Oil Company.

I am pleased to appear here today in response to your request for commentary on several issues which are relevant to the subject of transportation of natural gas from the North Slope of Alaska to markets in the lower 48 States. These issues are:

Prudhoe Bay gas reserves and their deliverability;

Gas processing or conditioning facilities;

Gas sales contracts and pricing; and

Producer pariticpation in the financing of gas transporation facilities.

Sohio has previously made known its position on these issues in response to various congressional questionnaires and in the course of Federal Power Commission proceedings relating to this subject.

I will submit for the record a written statement addressing each of these issues, but will limit my remarks today to the issue of producer participation in the financing of such transportation facilities, an issue on which I have personal knowledge and which I feel reasonably qualified to discuss in detail.

Sohio's financial condition is unique among the major North Slope participants. To the extent that producer participation in the financing of a gas transmission system is critical to your deliberations, I believe that you should be aware of Sohio's limitations in this regard.

Sohio's current estimate of proven gas reserves of the entire Prudhoe oil pool and its associated gas cap is 8.5 trillion cubic feet of solution gas and 16.9 trillion cubic feet of gas-cap gas. The Prudhoe Bay unit agreements provide that we will have production participation of approximately 53.2 percent in the oil rim and approximately 14.28 percent in the gas cap, in each case before deduction of the royalty interest of the State of Alaska. Thus, Sohio's interest in gross gas production will approximate 27 percent of the total proven Prudhoe Bay gas reserves.

Mr. Roncalio. What is the Alaskan royalty on that gas?

Mr. Miller. That is one eighth, 12-1/2 percent.

In the early 1970's, Sohio was a participant in the Northwest Project Study Group, a predecessor to the Gas Arctic Project, one of the unsuccessful applicants for certificates to construct a pipeline for the transportation of North Slope gas.

Our intention as a member of this study group was made known from the start--that is, to participate only in the study phase of the project with no desire to enter into the gas transmission business. Sohio reiterated its original intention when it withdrew from the project in 1974.

At that time, the study phase had drawn to a close, and the Gas Arctic Project was preparing to file applications with the Federal Power Commission in the United States and the National Energy Board in Canada to certificate this project.

On March 7, 1974, Sohio notified the other participants in the study group of our decision to withdraw. Our letter communicating our intention stated, among other things:

''The size of the project has brought us to a point of real concern. The participants in the study group have reocgnized that the companies that ultimately band together to finance and build the project will probably include a number but not necessarily all of these companies, and will probably include some companies not now participating. In fact, the participation in the project may well be determined by a company's success in obtaining gas contracts for Arctic gas. While it is likely that this group of companies will themselves be able to raise a substantial part and perhaps all of the funds necessary to construct the project, Sohio feels very strongly that in order to make the project fully viable, both the Canadian and the U.S. Governments must act as backstops or insurers to the project to satisfy the guarantees on completion and operation which lenders will require. Sohio feels that this concept should be communicated to both governments from the outset and on a continuing basis, even though the exact extent of government participation cannot be determined until the group of companies which will actually undertake the financing and construction of the pipeline system is known. It is our belief that failure to commence dialogue with the two governments involved very early will ultimately lead to significant delay of the project.

''We recognize that some companies in the study group may not share our view and that most would prefer to leave the project entirely in the private sector. We certainly would agree with the latter point as a general rule. The size of this project, however, makes that unrealistic and Sohio firmly believes that some government participation is essential and that it would be a serious error not to apprise our governments of this fact from the beginning.''

Mr. Roncalio. The most asounding hearings I have ever run into in my 61 years on earth, asking the government to step in. It is unbelievable.

Mr. Miller. Perhaps we can indicate why we take that position in this particular instance.

Mr. Roncalio. Surely.

Mr. Miller. Following our withdrawal from the study group, Sohio's posture with respect to the Gas Arctic Project and similar proposals can be best characterized as one of simply monitoring developments. From time to time, however, we have been asked to review our position with regard to participation in the financing of a transportation system for North Slope gas. Our postion on this matter remains the same, however, and we foresee no change in circumstances which would result in a different conclusion on our part.

We are well aware of the financial burdens commensurate with projects of the magnitudee required to transport North Slope gas to the lower 48 States. In developing our crude oil interests in the Prudhoe Bay field and in constructing the Trans-Alaska pipeline system, or TAPS as it is commonly referred to, tankers and other related facilities to transport North Slope crude oil to market, we are, initially, investing an aggregate amount of approximately

$6.2 billion.

To provide perspective on the relative magnitude of this requirement, Sohio's total assets immediately prior to our involvement in the North Slope of Alaska were under $1 billion. Thus, the $6.2 billion program being financed represents an enormous undertaking which is severely taxing our corporate credit capacity to say the least.

Of the $6.2 billion of initial development costs of our Alaska related projects, about $5.2 billion is being obtained from external sources with the remaining funds being supplied from internal cash generation from existing operations. To date, we have borrowed approximately $4.5 billion and have raised approximately $136 million through the sale of common stock.

To provide protection for their investments, and to minimize the degree of risk to which they are exposed, lenders to Sohio have imposed stringent restrictions upon the company which, among other things, establishes a maximum amount of indebtedness that can be incurred for development of our Alaska related projects and limits the amount of indebtedness that can be incurred for other purposes prior to the completion, as defined in the governing agreements, or TAPS.

Indebtedness is broadly defined by these agreements to include substantially all financial obligations of Sohio and its subsidiaries including balance sheet debt, leases, charters, debt of other parties secured directly or indirectly by guarantees, throughout agreements or similar financing agreements of Sohio or its subsidiaries.

For the time period following completion of TAPS until 1998, at which time relevant restrictions will be removed by the final repayment of the associated debt, Sohio is prohibited from incurring additional direct debt or funded debt beyond a prescribed ceiling. This ceiling is based on a maximum debt-to-equity relationship wherein debt may not be incurred if, as a result, total debt would exceed:

(A) 60 percent of capitalization if such debt is incurred during the first year following TAPS completion,

(B) 55 percent of capitalization if the debt is incurred during the second year, and

(c) 50 percent of capitalization if the debt is incurred thereafter.

Together, the pre-completion and post-completion covenants, although restrictive, were designed to provide reasonable flexibility to permit us to complete the financing of our planned projects while also providing maximum protection of the lenders' investment.

Upon full completion of the initial development of the Prudhoe Bay oil field and the construction of TAPS, tankers and the other related facilities necessary for producing and transporting North Slope crude oil to market, Sohio's total debt is expected to be in excess of 75 percent of capitalization.

Thus, we will be prohibited from borrowing additional funds at that time. We estimate that a period of at least 5 years must elapse before the debt-to-equity relationship will be reduced to a level that would permit any significant new debt incurrence. Any such borrowing capacity created at that point in time represents only the technical ability to borrow funds within the constraints of the debt convenants.

Our current financial plans, which management considers prudent, contemplate that our debt as a percent of total capitalization will be reduced to and maintained at a more traditional level in the long term. Prudence would dictate that the company not expose itself to a continuing policy of borrowing to the limits of its legal debt capacity even if the investment community would continue to permit it to do so.

During the post-completion period, the definition of funded debt contained in our covenants incorporates, with a $50 million aggregate exemption, guarantees of debt of other parties in which Sohio does not have an equity interest and guarantees of debt of other parties in which Sohio does have an equity interest to the extent such guarantee exceeds Sohio's equity interest on a precentage basis.

Thus, Sohio, as an outside party, would not be capable of providing an underlying guarantee of the debt obligations of a gas transportation system so long as its deb-to-equity relationship exceeds the limtis discussed earlier.

If Sohio held an equity interest in a project, certain forms of financial obligations could be incurred even though the incurrence of direct debt is prohibitied; however, such additional burdens would not be advisable at a time when a deliberate effort is being made by the company to reduce its debt-to-equity relationship to a level considered acceptable by the investment community, credit rating agencies and management, itself.

Furthermore, the investment community would attach little value to such guarantees if they considered the company to be incapable of honoring them. Beyond any doubt, the wisdom of incurring major commitments of the magnitude which will be required for meaningful participation in a project such as this would be questionable.

Indeed, with the tremendous burden of our annual debt service requirements, and the substantial additional capital

98-069 O - 78 - 41

which will be required to complete the development of, sustain production of, and maximize the ultimate recovery of oil from Prudhoe Bay, the company must preserve borrowing ability to meet contigencies which might arise.

If, for reasons we cannot now identify, Sohio were to guarantee, in any form, the financing of a system to transport North Slope gas, our ability to met unforeseen contingencies associated with current endeavors would be seriously jeopardized and our ability to invest in other projects would be virtually eliminated.

We would be compelled to preserve our financial capability to meet potential problems which might arise as the project proceeds. Such problems can occur before, during, and after construction and these potential problems are well known not only to those of us directly involved in the construction of TAPS, but are equally well known to the major lending institutions in this country.

In summary, Sohio does not have the capability to provide any meaningful financial support to a North Slope gas transportation project now or for a number of years in the future.

We have, on prior occasions, stated our concerns regarding the ability of the likely owners of this project to finance the construction of such a system in the absence of governmental support. We still believe that in order to make any project to transport North Slope gas to market in the lower 48 States fully viable, the government must, in some fashion, act as a guarantor or insurer to such a project to provide the assurances lenders will require.

While we believe that such projects are generally best left entitrely in the private sector, the extraordinary cost and the complexity of any North Slope gas transmission system makes it imperative that government and industry cooperate to bring this natural gas to market.

Thank you.

RPTR

Mr. Roncalio. Your conclusions answered my observation.

Mr. Miller. Thank you.

Mr. Dingell. Do you have a comment, Mr. Dickerson?

Mr. Dickerson. No, sir.

Mr. Roncalio. Are you with Mr. Goldsmith?

Mr. Dickerson. Yes.

Mr. Dingell. The Chair yields to my good friend.

Mr. Roncalio. I am a little startled about what I heard. I didn't expect any participation. I had hoped that someone among you would have come up with a statement that you would like to have seen the private sector get this since the financing sectors testified at our last meeting that they were willing and able to raise the 10 to $12 billion for this project. If it doesn't put a strain on them I would like to see it done that way.

Mr. Rawl. Mr. Chairman, I would certainly expect and like to see this project privately financed. We, too, recognize that the risks to us do not seem to be physicial risks in this project. The gas is there. The markets are there. The risks we envision would appear to be regulatory kinds of risks or the stipulations that might be included or the requirements, et cetera.

We would then say that we feel strongly that it should be able to be privately financed. There is capital in this country that would probably be looking for a place to be invested. If it cannot be privately financed, we think the government might look to ~~these~~ their stipulations, et cetera, on this project. We hope it would be privately financed. You have had people testify from firms that have advised the proposed builders that they felt it could be privately financed. We would like to accept their testimony on that.

Mr. Roncalio. We appreciate that. Thank you very much. Earlier this week a professor from USC testified any decision on the pipeline should be delayed several years to study the oil field more carefully. Do any of you feel there is not enough known now? You just answered that when you said you thought it was ready.

Mr. Rawl. This gentleman recognized before the Senate Committee that he had not made a study. ~~of it.~~ He has been hired by a legislative committee in the State of Alaska. He has talked to our people and I am sure some of the other producer people on this project. I have read his testimony as submitted.

In conclusion, I feel he has just taken a position that it is a very large oil field and a very large gas field. Since the ~~We do~~ industry does not now know ~~and I guess we all recognize~~ how to get 100 percent of the oil and gas out of the ground, he ~~He~~ seems to be suggesting that ~~although the oil is moving,~~ we ought to keep the gas in the ground to make sure nothing is done wrong. I guarantee you we have a strong feeling about getting ~~all~~ the maximum oil out of the ground and certainly ~~all~~ the maximum gas out of the ground. We have studied this field. These other companies have studied it. The State has had studies made. Obviously, in the earlier production life of a field there are some uncertainties, but there are plans made that if water has to be injected, it will be injected in a timely fashion. I feel badly about that testimony because I thought it was very poorly done and not based on sufficient study.

Mr. Roncalio. We appreciate the rebuttal. Perhaps the

Sohio man would like to respond to it.

Mr. Goldsmith. I am not an engineer, but we have addressed this subject and testified before the State of Alaska on this issue. I am quoting from testimony from our vice president of production in Alaska who testified before the Alaskan legislation in 1976.

Mr. Roncalio. What was his name?

Mr. Goldsmith. Howard Slack. I will provide copies of this.

[The statement follows:]

insert 5a

Mr. Goldsmith. Atlantic Richfield has a high degree of confidence in its predictions of the Prudhoe Bay reservoir performance. This confidence stems from the fact that in the Prudhoe Bay modeling effort, the major elements of the model have been subjected to thorough sensitivity testing. That testing has been to identify those parameters that have the most effect.

Our thorough application of this approach and the subsequent follow-up work, both field and lab, has given us a high degree of confidence in our current forecast of the Prudhoe Bay performance. I am convinced that our present studies are adequate to demonstrate that from a reservoir performance standpoint early gas sales would be noninjurious.

Mr. Dingell. Did he indicate in what amount? He indicates sales. Now obviously there are two things that go into that. One is that the sale takes place and the other is the amount that takes place.

Mr. Goldsmith. We were looking at $2 billion a day.

Mr. Rawl. Yes. The $2 billion cubic feet of gas per day was included and we had an expert witnesses testify on that.

Mr. Dingell. These two fields are unitized?

Mr. Rawl. Yes.

Mr. Dingell. Do you contemplate sale from the gas cap or simply from the gas dissolved in the oil?

Mr. Rawl. We feel like the gas produced with the oil from oil wells should be adequate in early years to satisfy this 2 billion a day requirement. But, obviously, as the oil is depleted in the later years ~~you probably would take this on a gas plus.~~ some gas will be produced from gas wells.

Mr. Dingell. With apologies to my friend, if he would permit me to continue. Mr. Miller, do you have a comment that you would like to make on this?

Mr. Miller No, I don't think there is anything I can add to your understanding. I have no reason to think that their comments are not valid.

Mr. Roncalio. You are not ~~floating~~ flaring any gas are you, for goodness sakes?

Mr. Rawl. No, sir.

Mr. Roncalio. It will be reinjected?

Mr. Rawl. Yes, sir.

Mr. Roncalio How long can you reinject?

Mr. Rawl. We can reinject for as long as we have to. As some of you know, many years ago ~~there was~~ when oil and gas were found in this country and there was little market for the gas ~~for many years~~ we had no flare orders ~~office~~ in Texas and we returned the gas to the gas cap.s in many fields with no damage to the reservoirs.

Mr. Roncalio. All prior witnesses testified that the conditions in Alaska will necessitate the construction of a plant. You gentlemen this morning most certainly and without ambivalence let us know that you cannot and will not pay for any of it, it must be done by the transporting arm of the industry. Is that irrevocable? Can't there be some negotiation on it? It makes possible the sale of your product and gives us control of the by-products at the conditioning plant?

Mr. Rawl. Mr. Chairman, we as a group, the producers, have invested in the Prudhoe project roughly $12 billion. I can give you more numbers for the record if you would like. We envision that ~~you~~ the producers will have maybe a total of $23 billion ~~to invest~~ invested in this field through depletion. That is not including conditioning facilities or a pipeline.

Exxon feels ~~like~~ that here we have an industry that is a large industry, the gas transmission industry. They have a narrow focus. Their principal reason for doing business is to provide gas transmission. This would seem to us to be a project that the gas transmission industry would be more than happy to put ~~on~~ in as they have ~~rated.~~ stated.

The purpose~~s~~ as I have mentioned in my testimony, and these other gentleman have, too, of conditioning is to provide an efficient gas transmission project. I guess my feeling is that if ~~they~~ the pipeline companies find they cannot finance it, I would recommend that the committee look at the type of regulation that they have had over the years that puts them in such dire financial straits that when they have work to do, they cannot get the credit to do the work. I guess that is how I feel about that.

Mr. Roncalio. I know how you feel about that, but I wish there was some way I could have you appreciate the other side of that coin and how difficult it is to wrestle this deregulation thing. It is beginning to tear this country apart. If it can be financed by the Al-Can Company, will construction develop any new or untested technology of the nature of your gas or is it just another conditioning plant?

Mr. Rawl. I don't want to tie up this microphone, but, no, we don't feel like there is anything new in this regard. We do feel that the conditioning requirements for the gas will be more stringent than in a normal climate because as I mentioned the pipeline will be ~~there,~~ in the permafrost. ~~and some of those things will be more stringent than in a normal client.~~

Mr. Roncalio. Did I hear anything other than 90 cents per Mcf on that?

Mr. Rawl. That 90 cents was an escalated figure. I tried to keep up with all the figures in the President's decision and some are escalated and some are not. The nonescalated figure, compared to 30 cents in the President's decision ~~It~~, is probably ~~an offer~~ a figure like

64 cents.

Mr. Roncalio Thank you, Mr. Chairman.

Mr. Dingell. Mr. Meeds?

Mr. Meeds. Gentlemen, I am sorry that I did not get to hear all of your prepared testimony. I just came in at the end of the testimony by Mr. Miller. So I didn't get to hear it all. If I missed something, I hope you will set me straight.

As I heard the end of your testimony, Mr. Miller, it was that you were not exactly pleading poverty but at least the inability to contribute very substantially at the present time. Is that the thrust of your testimony?

Mr. Miller. Yes, I think so. Basically the message we have in terms of our ability to participate in a gas transmission system is that financially we cannot do so. We just are not going to be in a position to undertake any substantial additional financial requirements for a number of years.

Mr. Meeds. I hoped that was not the thrust of Mr. Rawl's testimony. I didn't get to hear that. I happen to remember seeing something in the morning paper. I dug one out of the trash can over there. I see that in the first six months of 1977, Exxon had profits of $1,220,000,000 which was almost twice what you had in 1972. Is that relatively correct?

Mr. Rawl. I don't remember the '72 figure. You are certainly correct on the ~~'75~~ first 6 months of 1977 figure.

Mr. Meeds. So you are ont pleading poverty?

Mr. Rawl. No, sir, our credit is very good.

Mr. Meeds. It is the government regulation that bothers you, right?

Mr. Rawl It is that plus we really do feel that despite the fact that we are more than viable financially, we are spending a lot of money. ~~We do,~~ F ~~for~~ for example, in the United States last year our earnings were about $1.2 billion but we spent about $2.4 billion. Our capital and exploration expenditures were $2.4 billion. The corporation has also stated that over the next four years our capital expenditures will be about $22 billion.

I stated that the total field here will need another ~~12~~-or $11 billion expended on it. We feel like we are in businesses that we have expertise in and we are not in the interstate gas transmission business. There are people who testified before these committees that want to build this pipeline. We are more than delighted to have them do it.

Mr. Meeds. You were testifying here about not, as I understand it, not wanting to participate in any way in the conditioning of the gas to get it ready for transmission; is that correct?

Mr. Rawl Yes, that is correct.

Mr. Meeds. I am a neophyte about this so perhaps you can enlighten me. Is that the general way this is handled in the lower 48? Do the producers not contribute to the conditioning?

Mr. Rawl Over the years it has varied, of course. But in recent years the Federal Power Commission has permitted the pipeline companies to include these conditioning facilities in their rate base. For example, in recent discoveries and developments in ~~recent-years-in~~ the Gulf of Mexico, the pipeline companies would put conditioning facilities on the producers' platforms and they would build and own those facilities and, of course, the connecting pipelines to the interstate system.

Mr. Meeds. Would you say that most of these facilities are owned by the transmission companies or more of the conditioning facilities are owned by the producers in the United States generally?

Mr. Rawl. I am afraid I cannot answer that. In recent years they have essentially all been owned by transmission companies but I can't answer your question.

Mr. Meeds. Can you answer?

Mr. Goldsmith. There has never been a conditioning plant or capital requirement for conditioning anything like what we are facing in the State of Alaska, so this is entirely new and different when you are talking about the cost.

Mr. Brown. Could you expand on that and give me relative terms? Excuse me, Lloyd.

Mr. Meeds. You ask him questions when it is your turn and I will ask him my questions. Go ahead, please.

Mr. Goldsmith. There is nothing to parallel this from the past. What we were talking about in the costs, whether they are 30 cents as the administration talked about or 60 to 90 cents, I think that that cost should in the case of Alaska be treated the same as it is in the case of the lower 48 States, added to the wellhead price.

Now as to who owns and finances the conditioning plant, all three of the competing pipeline projects omitted the capital costs of the conditioning plants in the capital estimates they provided you. Nobody has planned to finance that plant. This is of great concern to us.

Mr. Meeds. That is really why I am asking the question. If it is the custom for the producer to do that, then I would think that they were totally justified in omitting that. If it is the custom for them to do it, then they should have added it. That is really what I am trying to find out.

Mr. Goldsmith. We would say it is not a custom. Atlantic Richfield has written to both Secretary Schlesinger and to President Carter, this was a number of months ago. We stated that we had absolutely no interest in participating in the financing of the pipeline. We did indicate, trying to be of as much assistance as possible to bring this gas to production and without in any way committing any other North Slope producer, that we would consider assisting in the financing of the conditioning plant and we would help construct it and operate it or whatever, provided it is regulated separately from the pipelines because the Justice Department told us we cannot own anything of the pipeline and providing there is some system, a common carrier or contract carrier or some other regulated rate of return concept that will provide a fair return and one that you can rely on. That means we cannot rely on the kind of treatment we received from the ICC in the case of the Trans Alaskan oil pipeline.

Our expressed interest to the President and Secretary

Schlesinger on the conditioning of the plant has been dimmed because of what happened to us before the ICC. If Congress can find a regulatory system we can rely on, that would be different.

Mr. Meeds. If I could summarize, then, it is my understanding that you are still prepared to live up to your word, assuming they can find a system under which you feel comfortable to function?

Mr. Goldsmith. Yes.

Mr. Meeds. Is that the same for the other people here?

Mr. Miller. It is my understanding that it does go both ways in the lower 48. I think that is going to be a subject in negotiation as to who did it and how they were compensated for undertaking that.

Mr. Meeds. Mr. Rawl?

Mr. Rawl. No, we don't feel like we should plan to participate in this. We had four contracts signed for gas ~~share~~ sales back in ~~1974.~~ 1975 At that time the gas companies had agreed to include this in their part of this project. Now everything is subject to negotiation obviously, but I think you just have to look at that.

Mr. Meeds It seems to me--and I am just a neophyte looking at it--under the worst possible circumstances to your companies out there we are talking about $20 billion at wellhead.

Mr. Goldsmith. Investment?

Mr. Meeds. No, $20 billion in return for your product at the wellhead at the worst possible circumstance, it seems to me. Therefore, it seems to me that you ought to be prepared to participate in some of the capital investment that might be necessary to make that come true.

Mr. Rawl. Of course, that $20 billion, you understand, ~~Mr. Meeds,~~ that you are talking about is revenue, not income. ~~now.~~ There is a lot of cost associated with it. The State gets one third and the Federal Government gets one third----

Mr. Meeds. Is that all we get?

Mr. Rawl. That is all you are getting right now. I don't know what might be coming.

Mr. Meeds. Finally, did I understand that you gentlemen were questioning the financing system which at least to my knowledge has been developed by Loeb, Rhodes and Company, one of the top financial companies and helped develop by the Boston Company and the Bank of America is involved, and the United States Treasury says it is going to work and the President says it is going to work and you are now telling us it is not going to work.

Do I understand that correctly?

Mr. Goldsmith. May I comment?

The original financing plan proposed by Al-Can when it seemed to win the race among the three projects selected for route preference reasons or political reasons or whatever, was a financing plan based on a detailed six point consumer guarantee plan. It was an all events, tariff limitation on the power of the State public utilities commissions and the Federal Power Commission even to change rates. Through absolutely all risks and costs on the consumer, had such a plan been legislated by Congress, then one would have to admit they had a financing plan that would work. But it was politically naive for them to believe that such a total bearing of risks by the consumer would be agreed to by the Congress.

Mr. Meeds. That means it is politically naive by Loeb, Rhodes and Bank America and other people?

Mr. Goldsmith. In my opinion. That was their plan and that was what was being looked at by the administration at the time they seemed to be tapping Al-Can. At the time Al-Can got ready to testify before this committee I suspect, and do not know, that they feared that the major issue that would slow them down would be the issue of a consumer-supported financing plan.

Therefore, if you read very carefully the testimony made by Mark Mallard of Loeb, Rhodes before these committees, he did not say he had a financing plan. He indicated that he hoped he would be able, especially if he could get support from the State of Alaska and the producers, and we have indicated that we can't or won't, that then he might be able to get the money and he would want to go out and try.

I have talked to the senior lending officers, the senior and executive vice presidents of the largest insurance companies in the United States. I have talked to the largest commercial banks in the United States. I have talked to other investment banking firms that are considerably larger than Loeb, Rhodes and have done a great deal of financing, including those who are the advisors to the two competing projects. In all cases all of these people are extremely skeptical as to the ability of the project to obtain the quantity of capital required and skeptical about making loans to it.

Mr. Meeds. I would assume they are skeptical. I have heard that a long time ago. With your help and participaticin it would make it better, wouldn't it?

Thank you.

Mr. Roncalio. You made inquiries and they volunteered the information. Was that while El Paso was still in the ball game?

Mr. Goldsmith. Yes.

Mr. Roncalio. Then that makes a difference.

Mr. Goldsmith They were skeptical about all three projects unless there were Federal Government guarantees of some sort.

Mr. Roncalio. I see. I am going to call on a man with some very tough questions for you, Mr. Brown of Ohio.

Mr. Brown. Who placed the debt limitations on Sohio and Arco? I gather Exxon does not have the same debt limitation problems that the other two companies testified to?

Mr. Miller. With regard to Sohio, these debt limitations were negotiated and entered into by the company and the lenders the first time when we placed privately with a group of insurance companies and pension funds $1,750,000,000 of debt. It was in the course of negotiating that financing that these covenants were agreed to.

Mr. Brown. Are those reviewed by the Securities and Exchange Commission?

Mr. Miller No, sir, not in this place. This was a private place.

Mr. Brown Do you have any debt that is reviewed by the Securities and Exchange Commission which has those covenants?

Mr. Miller. We have public debt, but it doesn't incorporate those same things, no.

Mr. Brown. How about Arco?

Mr. Goldsmith. Congressman Brown, I spoke to two restrictions on Atlantic Richfield. One was a debt indenture which was from one of our predecessor companies, the Richfield Oil Corporation, which was a privately-negotiated debt instrument which has this limitation that our tangible assets must be 2-1/4 times our funded debt and that guarantees of someone else's debt counts as funded debt.

Mr. Brown. That is specifically in that limitation; correct?

Mr. Goldsmith Yes. That was an arm's length restriction which is a common one for lenders to make. We are now in excess of that limitation in the sense that the total additional amount of money we could borrow until such time as our profits increase or our debt is reduced is about $350 million.

So we could not take on without violating that indenture an open-ended guarantee that could result in billions of dollars having to be borrowed against our credit. You will remember that the administration expects a $4 billion cost overrun at least.

So we are looking at $13.7 billion or whatever. That would put us into default in the indenture. We have acceleration choices in other debentures which say if you are in default of one, they all come due.

The other thing was that the companies require a ratio of two to one in the case of our preferred stock. So we could not amend those articles of corporation without the agreement of the preferred stock shareholders. The preferred stock shareholders have no rights to convert into common stock so they would have no motivation to approve a change in the ratio. It would be to their detriment.

Mr. Brown. That is a limitation blessed by the SEC or not?

Mr. Goldsmith. They don't get involved in blessing those.

Mr. Brown. Well, I didn't mean to use that word. It is filed with them, right?

Mr. Goldsmith. Yes.

Mr. Brown. What can flow from this is a sharp increase in your necessity to get financing or the necessity to dispose of the company to somebody else who can take you over; is that correct?

Mr. Goldsmith. Well, sir----

Mr. Brown. Is that the alternative?

Mr. Goldsmith. One could attempt to call this bond debt and buy it back from the lenders at a premium if they will sell to you. I have tried to do that on occasion and believe me, they rob you.

Secondly, in the case of the preferred stock, we would have to go to the preferred shareholders and ask consent which in my opinion they would not give.

Mr. Brown. Then the alternate choice is that company goes up for grabs because the stock comes down?

Mr. Goldsmith The company becomes insolvent.

Mr. Brown. Then what happens?

Mr. Goldsmith. Then all the lenders stand in line.

Mr. Brown. Unless your find something to take it over, who is in a better position to deal with the debt problem? Sohio, if I understand correctly, is in worse shape than Arco in this; right?

Mr. Miller. Sohio has tighter financial constraints.

Mr. Brown. Where are you in the Fortune 500?

Mr. Miller I don't know.

Mr. Goldsmith. We are 12.

Mr. Brown. Exxon is 1 or 2; correct?

Mr. Rawl Correct.

Mr. Brown. The only one of the three who could finance their part of it; correct?

Mr. Rawl. We may be able to afford to, but I guess you understood that it is not our plan or intention to do so.

Mr. Brown. I did.

Mr. Roncalio. Atlantic Richfield would not obligate itself to guarantee the $13 billion. When you only make a contribution of one fourth of the line's capacity, you would only obligate yourself to one fourth of the debt; right?

Mr. Brown. Hopefully.

Mr. Goldsmith. Hopefully, but they have given us no structure as to how this guarantee would be allocated between producers. They are thinking of these three companies, but there are other companies that have production.

Mr. Brown. You don't like to subsidize the production of your competitors up there and this is a factor?

Mr. Goldsmith. Yes, and we are being asked to help the Canadian gas producers.

Mr. Rawl. I think these comments about debt are interesting, but I think there is something more fundamental here. We are being asked to give somebody a blank check without any management rights.

Mr. Brown. You are prohibited from management rights?

Mr. Rawl. Yes, sir, and how do you explain that to your shareholders and how do you footnote that whether you are talking about Exxon's ~~ground~~ balance sheet or Sohio's? How can you say to your shareholders that we can't tell you whether we are going to make a return on it or not? This whole question of guarantees, possibly the U.S. Government can do that, we can't do that.

Mr. Brown. Have you tried any Georgia banks?

Mr. Roncalio. When Atlantic Richfield acquired Anaconda, what did it add to your debt position?

Mr. Goldsmith. We used equity securities in order not to increase our debt. The actual cash outflow was about $300 million which was less than what we received from selling our Canadian operations because of how we were disturbed about operating in Canada which obviously relates to our interest in participating in another project in Canada.

Mr. Roncalio. Did it add to your tangible assets?

Mr. Goldsmith Yes, sir.

Mr. Roncalio. Three times that much perhaps?

Mr. Goldsmith. Yes. It actually would have not impacted this ratio.

Mr. Roncalio Thank you very much.

Go ahead, Mr. Brown.

Mr. Brown. Thank you.

I would like to ask if anyone in the White House or BOE or DOT ever asked the companies about the detail of your financing arrangements, and the Treasury, as to whether or not you can legally obligate yourselves to this extent?

Mr. Goldsmith. I have personally visited with the Assistant Secretary of the Treasury Altman.

Mr. Brown. At his request?

Mr. Goldsmith. At my request, to express my views that I thought these projects could not be financed without either the total consumer guarantee legislated by Congress or government guarantees. I have also said this to Loeb, Rhodes and the advisors for El Paso, Whitewell, and Morgan, Stanley, the advisors for the Canadian pipeline.

When Mr. Miller and I were on the gas committee we insisted any presentation they make to the FPC and Congress should indicate that government guarantees be required because we felt it could not be financed any other way.

Mr. Brown. Have you specifically mentioned to Mr. Goldberg or Mr. Martin who felt this should be the problem of the producers and should be without the legal problems?

Mr. Goldsmith. I am surprised Mr. Martin is not aware of our correspondence with Secretary Schlesinger.

Mr. Brown. Mr. Miller?

Mr. Miller. We have had no dialog with any of them on our financial condition. We submitted a paper to the FPC in this matter, the same views we expressed today. Whether they took note of those I am not aware. At least it was available to them. I would have thought they would have.

Mr. Brown. If the pressure is brought by the Federal Government or if the Congress should in some way mandate your participation in this, what would be the impact on your company?

Mr. Miller. Well, I don't know quite how we would comply with that. I suppose the only way we could do it would be to go back to the lenders and indicate to them that we needed that modification of our covenants and see if they were willing to enter into that kind of arrangement.

I would suspect that we would not be successful in that regard.

Mr. Brown. If they refused?

Mr. Miller. We have a legal obligation to them. I think we would be in a little bit of a bind, given the restrictions and the compulsion to enter into it. I don't know how one would settle that.

Mr. Brown. Do you want to speak to the legal obligation?

Mr. Dickerson. If such an obligation were imposed upon Atlantic Richfield, we could decline to participate because of the risk to our shareholders. At that point I suppose it would be a question of how the Congress would seek to enforce the obligation.

On the other hand, like Sohio has indicated, if we felt

98-069 O - 78 - 43

the penalty for noncompliance was so substantial that we had to undertake to go back to the shareholders, we could do that. I suppose the gravest concern would be what penalty would be assessed if it felt it could not participate.

Mr. Brown. Do you feel there is a constitutional issue involved in this?

Mr. Dickerson. Yes, sir, that is a 5th Amendment question.

Mr. Dingell. If the Congress were to impose upon you the requirement that you participate and you did not participate, what would be your choices?

Mr. Miller That is the quandary that I said I don't know how to resolve. If Congress said we had to participate and we had contractual arrangements with practically every lending institution in the United States which says we are unable to enter into those obligations, it is not clear in my mind exactly how we would work our way out of that situation. We could speculate on all sorts of things, but I don't know what the right answer to that is.

Mr. Dingell. I am curious because obviously the matter has come up. I am not indicating a position on my part. I am curious.

Mr. Rawl. Mr. Chairman, I assume we would check to see whether under the Constitution we could be mandated into taking our money and ~~someone insist that we invest it into~~ investing it in something we did not want to invest in.

Mr. Dingell. How about you, Mr. Goldsmith?

Mr. Goldsmith. Chairman Dingell, presumably the way this would happen is through the FERC in some fashion with its gas pricing I would assume. Such a creation of an illiquid position which would violate our stewardship to our shareholders would in my view make production of North Slope gas uneconomic. My recommendation would be that we not commence negotiations of gas sales contracts.

Mr. Dingell. So you are saying you would not produce gas? You would either reinject or flare?

Mr. Goldsmith. We would not flare.

Mr. Rawl. We cannot legally flare.

RPTR

Mr. Brown. As I understand, we are at the point then where the producers say they can't or won't finance the project because they think the risks are too great, and the control is too total in the hands of the government to just simply destroy their opportunity to pay it back, and their creditors will not let them do it.

So, there is a legal problem.

Mr. Roncalio. Not totally, is it. Wasn't there a little qualification in the case of Sohio and Atlantic, a modest one regarding conditions?

Mr. Goldsmith. In the case of Atlantic Richfield only.

Mr. Roncalio. I want to make sure that exception is on the record.

Mr. Brown. Yes, but the understanding had to be, if I may, at this point, that it had to be an assured guarantee that the costs would be covered of that project, an assured guarantee by the Federal Government.

In other words, the same kind of guarantee that the pipeline has that they are going to make money on this project to return whatever investment they have in it.

Now, you do not at this point have that guarantee.

Mr. Goldsmith. That is right.

Mr. Brown. Even for the gas in the ground, for that matter.

Mr. Goldsmith. That is right.

Mr. Brown. I just want to pursue that for a minute. I want to get clear in my mind, or at least the way I see this, and have it corrected by my colleagues here and, if I am in error, that the pipelines won't finance this either, or can't.

Mr. Brown. I don't know which it is in their case because I don't recall their testimony that well. Maybe we never asked them that question, but the either won't finance it or can't. But, if they did finance it the Federal Government, under its regulatory authorities, guarantees their return, does it not?

Mr. Goldsmith. Yes, sir.

Mr. Brown. You do not have your return guaranteed on the gas you found?

Mr. Goldsmith. Right.

Mr. Brown. And so the government can say to you, ''If you don't put some of your money into this thing, we will set that wellhead price so low'----

Mr. Roncalio. $1.40.

Mr. Brown. ----'that you cannot make the return on the anticipated amount of gas that you have to sell.'

Mr. Goldsmith. Right, sir.

Mr. Brown. So that is where Mr. Goldman will have his leverage, I assume, when the time comes, and I understood his testimony this morning that he wanted to have good cooperation between the DOE, the Administration and FERC, so that if the ERC can be party to this process of forcing you to participate in the financing of this project. Do I understand that correctly?

Mr. Goldsmith. Yes, sir.

Mr. Brown. Wait a minute. One other point. And the

Federal Government, according to Mr. Goldman's comments to me, the administrative branch at least has said they won't guarantee the project either, the Executive Branch has said that because they will not come, he says, they will give us a letter from the President that says that they will not guarantee the expenditure of this money from the taxpayer.

But, it was left a little up in the air as to whether or not they would set the rates to the consumers if you all play ball. They might set the rates to consumers so high that somebody would have a return that would see that the whole project can be financed if you guys participate.

Mr. Goldsmith. Yes, sir.

Mr. Brown. But now that did not set the wellhead rate. That only spoke to setting the rate for the pipeline.

Mr. Goldsmith. Yes, sir.

Mr. Brown. So there is no guarantee from them on the wellhead rate, but there is some suggestion that the pipeline rate might be okay.

Well, I thought I understood that. I just wanted to try to get it down.

Mr. Goldsmith. Could you elucidate there. As far as the conditioning plant is concerned, it could be done in any one of three ways.

The gas transmission companies could go on it and make it part of the pipeline project.

Secondly, it could be an entirely different regulated entity with the rate of return concept.

Thirdly, we could deregulate gas, and sell the gas at the tail-end of this conditioning plant, with all the conditioning done, for what it is worth, and we would be happy with that solution.

Mr. Brown. Is there a time problem?

Mr. Roncalio. There was a minute ago, but there is not now. You have unlimited time to the next ten minutes.

Mr. Dingell. Off the record.

Mr. Brown. Mr. Chairman, I will be glad to subside for a while.

Thank you, Mr. Chairman.

Mr. Dingell. The Chair recognizes Mr. Moore, and then Mr. Gammage.

Mr. Moore. Thank you, Mr. Chairman. I only have two questions.

One, I don't know much about this loan guarantee proposition, but the gentleman on the end referred to that as an investment a moment ago. How would that be an investment to your company, to have a loan guarantee on this pipeline?

Mr. Rawl. I may have miscommunicated. A loan guarantee would be something where we would put up our credit or our money, and other people would manage this project, and use our money, and we might get, as they said in the President's decision, a modest fee because there is supposedly very little risk.

Now, I submit that if there were very little risk, they wouldn't need loan guarantees on this thing. Basically, what I am saying is you just give someone else a blank check and you have no management in that. We couldn't operate ~~on~~ like that.

Mr. Moore. You wouldn't know what the return is going to be for having given someone your blank check--you don't know what the return is.

Mr. Rawl. That is exactly right. You don't.

Mr. Moore. The second thing I would like to ask is, let's go back to an old outdated notion, free enterprise, and say there could be a way worked out in the Justice Department where you could own a proprietaryship interest, where you might get a return by owning an interest in the pipeline.

Would you then be interested in investing in it? I ask all four of yu that question.

Mr. Miller. I don't think we would be. We are not in that particular business. We have no desire to get into the gas transmission business.

In addition to our financial limitations, if we are excusing those for the moment, if the Justice Department said it was okay, you are still in a very highly regulatory are of business. So, I don't think that is really back to the old notion of free enterprise.

Mr. Moore. It is halfway back.

Mr. Brown. Would you yield, because I want to clarify a point. You said putting the restrictions aside.

Mr. Miller. Yes.

Mr. Brown. But that doesn't really answer his question. Are those restrictions limiting in terms of equity ownership?

Mr. Miller. No, I am saying--we have several problems as a corporation. The first and foremost is our financial limitations. If we set those aside--

Mr. Brown. I want to know what that means with reference to the question as he posed it, which was equity.

Mr. Miller. In order for us to take an equity position you are going to have to guarantee I think an equal portionof the debt. So that for us to take an equity position we have to do two things.

The first thing we would have to come up with is the capital required to have that equity position. The second thing we would have to do would be to guarantee as a sponsor ora proportionate share of the debt. So, it is not possible for us to take an equity position.

Mr. Moore. What you are saying is under any circumstances you cannot participate in this pipeline, ownership, guaranteeship or whatever?

Mr. Miller. That is right. The only thing I was advancing is the notion that if we were able to do so under the free enterprise idea that you suggested, we still have the regulatory concerns and the political risks that probably would have us opt not to take a position anyhow.

Mr. Moore. How about the next two companies?

Mr. Goldsmith. Atlantic Richfield is very happy with the private enterprise system. We feel comfortable in measuring exploratory production and economic risk. We cannot measure political risks.

We are in the midst of a very unpleasant experience, after hving complted the Trans-Alaskan pipeline, with an investment of over $8 billion, and have found that the ICC has changed a regulatory practice that has been in existence for decades, retroactively.

That was all one would need from the standpoint of discouraging him from investing further in regulated utility type enterprises. So, no, we have no interest in an equity position in the gas pipeline.

Mr. Rawl. Mr. Moore, at the risk of being a little redundant, before you came in I pointed out that the risks in this one are strictly regulatory, that type of thing.

As a consequence, here we have a very large volume of gas, and we have a market, and if this cannot be financed by an industry whose principal objective is to provide interstate gas transmission, well then I would suggest that the regulators, or in this case the Congress, certainly has an opportunity to have some input, take a look at the requirements on this pipeline of various types, or the stipulations, or whatever we might get into in overlaps in bureaucracies, and they will probably find why this thing cannot be financed.

If some improvement can be made in that area, I would suggest that it could probably be financed. It wouldn't seem to me if it couldn't be financed for those reasons that it would not be very intelligent of producers to step into the same environment and finance it.

But, we are not in the business, and it is not our intention now to get into that kind of business.

Mr. Moore. Thank you, Mr. Chairman. I will conclude my questioning by adding a comment.

I really hope that no producer leaves our hearings with any thought in his mind that there is not going to be one hell of a fight in the Congress before we put up one penny of federal money to build this pipeline.

I am going to tell you right now, if I am back I am going to dedicate everything I have got to seeing to it not one cent of federal money goes into that pipeline. So, we either straighten out the regulatory problems or we don't build it, or private enterprise builds it, as far as I am concerned.

Mr. Roncalio. Mr. Gammage?

Mr. Gammage. Thank you, Mr. Chairman. I won't take my entire five minutes. I don't really have any questions, just one comment.

Down in my district recently we have had a very similar problem. Exxon would be familiar with this because they were a participant, the proposed off-shore terminal construction, importation of about two and a half million barrels a day of crude oil, feeding about 43 percent of the nation's refining petrochemical complex, a facility that will now not be built because in issuing its permit the Department of Transportation, with its window in from the Justice Department, sought to impose regulatory standards they had not previously been given the permission of Congress or the courts to impose.

So, Exxon, Mobile and Gulf bailed out. Now nobody can build it. We won't have that two and a half million barrels a day of crude oil. It also is the strategic petroleum reserve--we are going to have to lighten that stuff and tanker it with smaller tankers, and face all the environmental hazards of navigating the channels, and additional costs of transferring it from the supertankers to the lighters and smaller tankers.

The state passed back up legislation so that it could be constructed publicly with an issue of bonds, but with the proviso that it would have to be guaranteed by the same participants and virtually underwriting of those bonds by those participants.

So, apparently it is not going to be built at all. What we have got is a situation where we see a need and have a resource available and we come forward in Congress with a very idealistic attitude of making that stuff available, and then we instead of licensing those facilities in the business we regulate them out of existence.

I think it is a serious problem. I think Mr. Moore spoke well in his questions.

Mr. Roncalio. Mr. Meeds?

Mr. Meeds. Thank you, but not at this time, Mr. Chairman.

Mr. Roncalio. Mr. Moorhead?

Mr. Moorhead. In the event that the transmission companies cannot borrow the money necessary to build the pipelines, and the government does not wish to put up a subsidy, or a loan guarantee, aren't the major oil companies producing the gas in their oil fields going to lose an awful lot of money that would otherwise be available to them through the same of gas?

Mr. Goldsmith. Yes, sir.

Mr. Moorhead. You have a real positive econcmic need for the pipeline to be built.

Mr. Goldsmith. Yes, sir.

Mr. Moorehead. I certainly would agree with you that it will be ideal if we could get the transmission companies to build it. They are in that business. But I would think that, as you can here, there is not unanimity on the desire of the Federal Government to provide a profit for the major oil companies.

If you heard the President lately, I don't think he has much of a desire in that direction, either.

98-069 O - 78 - 44

So, it would seem that perhaps you are going to have to work together. I want to see this done through the free economy. But maybe if there is an economic need the oil companies are going to have to at least help with the guarantees in order to insure profits.

We don't want the gas to go to waste. I know you don't, because that is money in the bank.

Mr. Goldsmith. I share your concern, Congressman Moorhead. We are very reluctant to recommend government financial participation in what should normally be a private enterprise project.

It has not been our posture or practice in the past. But, we find here a project of capital cost greater than any project ever built in the history of the world. We find one that is international in nature, that crosses two countries. We find an artificial marketplace situation.

This is not the real marketplace, as you know, Congressman Moorhead, because here we have regulation of gas prices at the wellhead, we have regulated rates of return on the pipeline, regulated prices charged to consumers. So, we cannot look at the commodity value of the gas.

I think gas producers could be encouraged to work with others to form a project if there were deregulation of natural gas, and we went back and let the marketplace sort everything out.

You know, Congressman Moorhead, if you saw the draft of this executive agreement between Canada and the United States, it was agreed in that executive agreement that will come before the Congress that there would not be government financing, any government financial support, nor would there be any consumer financial support.

Either one would do it. We could have an all events tariff and the consumer would be the only one at risk rather than the Federal Government. But, they propose in that treaty not to have any financial support from either one, which raises additional concerns of any potential equity investors or lender to the project.

It seems to suggest that the Canadians might feel more free to deal in an adversary way with the project if they are not directly impacting the U.S. Federal Government or the U.S. consumer, if they are picking on some oil companies or gas transmission companies.

We have been nationalized enough around the world to be very concerned about starting out on a project with that sort of expression of attitude.

Mr. Moorhead. Isn't it true there is a treaty, however, that virtually protects the project from nationalization and guarantees to the American consumer the product without any discriminatory taxation?

Mr. Goldsmith. I am not an expert in international law, and perhaps our counsel would like to comment. I am told, sir, we cannot rely on that executive agreement as actually limiting the power of the provinces and the various local governmental units within those provinces as far as their taxation of this project.

The dominion government, which as you know hasn't even sold the confederacy issue that we attacked 200 years ago, has not even offered to exempt from withholding tax in Canada the interest that will be paid by the Canadian entity, which will enlarge the cost of financing.

We talk of Federal Government financial support. We are not talking of the Federal Government loaning the money. We are suggesting here one of two kinds of federal financial support, for which there is a great deal of precedent in the first one, that means simply government guarantees of the debt, which would save the consumers as I estimated 30 tc 40 cents an MCF on this gas, we have this in Title XI for ship financing.

We have situations like Lockheed, of course, which could not handle its financial affairs, and where the government guaranteed its debt until it could cross the bridge back to financial viability.

Now, those guarantees are being removed, and Lockheed is going on on its own. It didn't cost the government, anything. It hasn't cost the government anything to my knowledge, in guaranteeing Title XI financing. In fact, the government gets a fee for this, 50 basis points, one half of 1 percent per annum.

So, the government actually takes in revenue from that kind of a process.

Mr. Moorhead. It did on the Lockheed loan, too.

Mr. Goldsmith. That is right. Alternative tc guaranteeing the total debt on the project, which has this big interest saving element to it, another alternative is simply touse the minimum tariff proosed by Alcan, where the consumer takes the risk after completion, he takes the risk of abandonment, the risk of excess cost, the risk of a long interruption.

That is already proposed by Alcan. That leaves one other major risk the leders are worried about. That is the risk of completion. So, the Federal Government could do somewhat like Lockheed. It could guarantee that the funds will be provided.

If private enterprise is not able to come up with enough equity and debt capital to complete this project, the

Federal Government will assure that the additional funds will be provided through government guarantees of that debt or whatever, which, if we can believe the project sponsors, are not going to be required because they don't plan on their being any overruns.

Mr. Roncalio. Mr. Moorhead, could I interrupt a minute?

Mr. Moorehead. Yes. I have promised Mr. Brown I would yield back to him. I woudl be happy to yield to you.

Mr. Roncalio. I would be glad to give each of you five more minutes.

Do you want them now?

Mr. Moorehead. I am not seeking the time for myself. I am seeking it for Mr. Brown.

Mr. Roncalio. Gentlemen, I have got some problems with what I have been hearing the last hour or so. Little things come up that sort of remind me. Were some of you disappointed that this came down on Alcan and not Arctic Gas or El Paso a little bit?

Mr. Rawl. No, sir.

Mr. Roncalio. Were you folks at Atlantic Richfield a little disappointed?

Mr. Goldsmith. Atlantic Richfield very carefully stayed away from endorsing any one of these three projects. We think this is something that is too complex, and should be sorted out by Congress and the American public. It is not for theproducer to say which project it should be.

Mr. Roncalio. We appreciate that. But were you a little disppointed? You served on the Finance Committee.

Mr. Goldsmith. Yes. Atlantic Richfield also subsidized the El Paso project, from the standpoint of preparing the financing plan for El Paso. I worked on that a little bit and talked to the Alcan people. My only concern about the Alcan project is simply the Canadian element.

Mr. Roncalio. I served on the Canadian International Joint Commission for three years, having water problems with General McNaughton, on the Great Lakes and the Saint Lawrence.

The provincial problems are not solved, but we have not solved our problems with the Indians, either. We are not all that far ahead of the provincial problems vis-a-vis Quebec and our Indians.

Gentlemen, Exxon does not have interstate transmission lines. Does Exxon engage in any intrastate shipment or own any intrastate lines?

Mr. Rawl. Yes, sir, we do.

Mr. Roncalio. I would like to also say this. I would like to have submitted for the record a chart on United States conditioning plants. How many of those are actually owned by the producers of the gas and how many are owned by those who own the transmission lines? Identify which producers own which conditioning systems, which transmission lines own theirs.

Mr. Brown. Would the gentleman yield at that point. Could you also include in that the point that I wanted to raise, when Mr. Meeds was questioning, and that is the unit value of those plants compared to the unit value anticipated in the Alcan plant.

Mr. Goldsmith. Yes, sir.

Mr. Rawl. We will work on it. But this may be a difficult thing to do because there are obviously a lot of, literally thousands of fields connected to ~~intestate~~ interstate pipelines. All of them have some form of conditioning. We will make every effort.

Mr. Roncalio. Do the best you can.

[The information follows:]

**********COMMITTEE INSERT**********

Mr. Roncalio. We have some figures submitted to our staff which would indicate a little differently from what your general observations were regarding percentage of product in the states that is producer conditioned and----

Mr. Rawl. I certainly didn't intend to--we did not talk about percentage owned by producers versus pipeline companies. What we said was that in recent years, probably since 1972 or so, the Federal Power Commission, rather than increasing the price of gas, permitted these conditioning facilities to be ~~involved~~ include in ~~with~~ the pipeline company rate base.

They also, you recall, had advanced payments ~~things,--which~~ After we got advanced payments in Alaska, they removed ~~that~~ them retroactively.

Mr. Roncalio. Back in the days, the happy days of the fifties, I wish that President Eisenhower would have never gone to play golf with his friends. You would have had the deregulation 25 years ago. But these accidents happen, and they hurt us, historically or whatever.

Five more minutes for Mr. Moorhead.

Mr. Moorhead. I yield my time to Mr. Brown.

Mr. Brown. Gentlemen, I begin to perceive a couple of things here that I think are interesting. One is what do you anticipate is going to be the total cost of this project? Separate out, if you will, the conditioning plant and the pipeline.

Mr. Goldsmith. Yes, sir. I will make a stab at it. Someone may have other views.

In 1975 dollars, Alcan talked to a $9.7 billion project, with a 40 percent overrun. When they talked to the dollars as they are actually incurred, as the money is spent, 1979, 1980, through 1983, whichis what really matters, without any overrun, they talked about $9.7 billion.

Our own internal escalation factors, which is what we assume is going to happen to construction and labor costs over the next five years, would track that sort of thing.

When we take the 40 percent overrun case, which is the one that GAO seems to say is the most likely one, and look at dollars as they are spent, 1979 through 1983, we come up with $13 billion to $14 billion cost of the gas pipeline alone, without the gas conditioning plant.

Now, we don't really know what this gas conditioning plant is going to cost, and we hesitate to give any numbers after our experience with the Trans-Alaska oil pipeline. We did make a study in 1971. All we have done is change that to current dollars, to dollars as they would be spent, and that told us it might be somewhere in the $1.5 to $2 billion range.

So, we must be looking at something in the $15 billion area for the facilities that need to be added.

Mr. Moorehead. Is there difference of opinion between any of you on that? $15 billion is relatively a small amount for the Federal Government. I think that is part of our problem. I think that those of us who are responsible for spending $460 or $480 billion a year have some difficulty understanding why you guys are having so much trouble with $15 billion bucks.

Well, can you help me with that?

Mr. Goldsmith. Yes, sir.

Mr. Roncalio. I would like to attempt to when you are through.

Mr. Moorehead. I guess the difference is we have the printing press. And also we set the prices in the commodities in which you are dealing. If I understand you-- have all three of you fellows been in the service?

Mr. Rawl. Yes, sir.

Mr. Goldsmith. Reserves.

Mr. Miller. I have not.

Mr. Moorehead. Well, I have, and I know that the chairman has. I have to say that I have your healthy fear of the government changing the rules on me from that experience some years ago.

Mr. Roncalio. You went for one year and came back four years later.

Mr. Brown. So I think I know what is eating you up. But, it comes from a different presumption.

Now, the $15 billion thing, that part bothers me. Can you tell me out of that--I shouldn't say it bothers me. I think the problem is that we are--$15 billion is a small project for the Federal Government.

Can you tell me what kind of guarantee we are talking about here on the part of the companies that are represented? What do you think out of that $15 billion would be what you are being asked for?

Mr. Goldsmith. Well, sir, Alcan has not structured their proposal. They simply first talked about guarantees of the project. Then they corrected that in letters to the Assistant Secretary of the Treasury, and said what we really mean is guaranteeing the overrun.

We don't know what the overrun is going to be, but if we take the General Accounting Office number, it is going to be $4 billion or more.

Mr. Brown. In other words, do I understand it that the Alcan is going to put up the $10 billion?

Mr. Goldsmith. They think they are going to put up the $10 billion. I question, sir, that they can raise $10 billion.

When we were part of this Canadian Arctic gas group, we had a study made by Morgan Stanley, one of the most prestigeous banking firms in the country, as to the capacity of capital markets for a single market, as well as for the financial capacity of the gas transmission industry.

At the same time, we estimated the total American gas transmission industry had the ability to raise between $1.5 and $2 billion of additional capital, if they suffered a one grade lower in their bonding rating.

They may be a little richer today than four years ago. But, they are going to have trouble raising $2 billion of equity that they propose to put in this pipeline. Their credit won't be worth a darn as far as borrowing any money on their credit.

I don't think they intend to put their credit behind it. What they proposed to do is to form corporations that will be the obligors, of which they will merely be stockholders. I have not heard anywhere they intend to guarantee the debt.

States.

We have no apologies to make for not helping the energy situation in the United States. We have been spending $2 billion a year for ech of the last three years, and expect to spend roughly that much for the next five years of capital spending.

The total capital spending of all American businesses is only $130 billion. We have been spending $3 or $4 billion in capital investments, to help to respond to the energy situation.

Mr. Brown. Let me interrupt you just a minute. The Chase econometrics figures on the coal conversion program alone, in the President's energy program between 1981 and 1985, the timeframe in which we will be building this project, is going to be--the requirements for capital expenditures are going to be $180 billion in that five-year period.

So, that is going to chew up a good hack of that $130 billion.

Mr. Goldsmith. That is right. We have about two billion

Mr. Roncalio. They committed 100 percent of equity capital.

Mr. Goldsmith. That is right, but not this debt that would be $7 billion without overruns, and would be $10 billion with overruns. They are not guaranteeing that debt. Lenders don't loan money unless people are going to repay whether or not the project is completed.

Atlantic Richfield's credit wouldn't be of any use to the project if we were required to take on one-third of the obligation, and if the project were not completed, and $13 billion had been spent and then you collapsed the project.

People wouldn't loan money on that basis with Arco's guarantee, or with Sohio's, if I may say so.

Mr. Roncalio. You didn't have any trouble getting money to build the TAPS.

Mr. Goldsmith. That is the reason our credit is now of lesser value today. We have extended ourselves. We have a debt ratio in excess of 40 percent, whichis the second highest of the 20 largest oil companies in the United tons of coal. We would like to use some of that financial capacity to develop that coal.

Mr. Roncalio. You are not talking about the same thing. You are talking about gross capital investment. You are talking about capital expenditures.

Mr. Brown. I am talking about fixed investment, $180 billion is the Chase econometrics estimate of the cost of coal conversion program from 1981 to 1985.

Mr. Goldsmith. That is right.

Mr. Brown. And you just said that the average annual investment is what?

Mr. Goldsmith. By our company is $2 billion.

Mr. Brown. No, by all American industry.

Mr. Goldsmith. All industries, $130 billion. It is predicted next year it will be $140 billion.

Mr. Roncalio. I submit for the record that you are talking about different things. The investment capital, gross capital investment in the USA, is $260 billion a year, which has nothing to do with capital investments that you gentlemen are talking about.

Mr. Brown. Gross capital investment. He is talking about industrial investment and gross capital investment----

Mr. Roncalio. Investors' money.

Mr. Brown. Gross capital investment I think includes housing and agriculture and a lot of other things that are not considered industrial investment. We are talking about industrial investment. When you are talking about the coal conversion costs, Chase econometrics was talking about industrial investment, which if you take the $180 billion and divide it over a five-year period, it is, you know, something like $30 to $40 billion a year.

Mr. Goldsmith. That is right. In fact, we are opening next month the largest coal mine in the United States, in Wyoming, with a capacity to produce 20 million tons of coal a year. You are familiar with that line, sir.

Mr. Roncalio. Yes.

Mr. Goldsmith. We are going to invest $205 million. We would like to build eight or ten more like that over the next ten years. And the country needs them, but we cannot use our financial capacity to guarantee other people's debts, and then develop coal mines.

Mr. Brown. I would like to conclude my questioning with just one other point. Would you each--well, I guess you cannot get together to discuss this.

I guess I ought to ask of you, then, because you are the financial officer here--would you advise me what the interests costs would be--maybe I should ask for each company--what the interests costs would be on the financing--I am sorry, on the guaranteeing of the loans if you had to come up with the money for that and what that does to your ability to meet your other obligations?

Do you understand what I am asking?

Mr. Goldsmith. Yes.

Mr. Brown. Because if you have to come up with the money, then your financing costs alone for the money that you would be guaranteeing--I would like to have that related to the debt that you now carry, and what it would do to that debt, your payments, the payments that you are now making, on the debt that you carry.

Do you have any question about what I am after? I have said it very badly, I know.

Mr. Goldsmith. The differing interest costs that we would incur if we were forced to produce on guarantees for this project as far as the cost of borrowing money.

Mr. Brown. That is right. I am not sure, first, exactly what you think the guarantees will amount to and what your share of that will be and then I want your projection based on your other company projections of what you would be obliged to pay in interest rates on the carrying charges of that as opposed to the carrying charges you now have on your current debt.

I have the feeling--I am not a stock holder, I just have an interest because it serves my area--that Sohio would be put to the wall by that.

Mr. Dingell. I think that is a very interesting question. Gentlemen, if you would submit that for the record, it would be most helpful. We will in each instance be very grateful for that.

[The information follows:]

**********COMMITTEE INSERT*********

Mr. Dingell. The Chair recognizes now the counsel of the subcommittee, Mr. Braun, for the purpose of asking questions.

Mr. Braun. We would like to get an idea of the respective shares of oil and gas reserves in the Prudhoe Bay that are held respectively by Exxon, Arco and Sohio. From the testimony we can glean that Exxon apparently controls 33 percent of the gas, and Sohio 27. Does that leave Arco's share at 40 percent approximately?

Mr. Goldsmith. Our share of the reserves is 7.5 trillion cubic feet, which is the same as Exxon's. That would be the same percentage.

Mr. Rawl. Let me just give you specifics as to ownership. You know there is the oil zone and the gas cap unit. Exxon and Arco each own 20.27 percent of the oil zone, and ~~they own~~ 42.12 percent ~~each~~ of the gas cap unit.

Then you can multiply ~~those~~ these figures times ~~those~~ the reserves that Mr. Miller gave in terms of what was in the oil zone and in the gas cap, and in our case and Arco's case you come up with about a third of the proven gas reserves in the field.

In Sohio's case it was the other figure. There are other people in these units, too, smaller interests in these units.

Mr. Braun. All right.

Mr. Goldsmith, you said that Arco had a high degree of confidence in the Prudhoe Bay performance. The question is, will Arco and ~~Exoon~~ Exxon and Sohio and the other Alaskan producers then guarantee the delivery of two BCF a day to Alcan?

Mr. Goldsmith. No, sir. Mr. Rawl, do you want to testify?

Mr. Rawl. We will not be able to guarantee the delivery of the gas. Studies have been made not just by these companies. The state has made studies. There have been outside parties that made studies. The ~~FPA~~ FEA looked at it and had studies made.

The gas is there. It is everyone's understanding and feeling and technical view that two BCF per day would certainly not strain that gas reserve. But when you talk about guarantees, you are talking about in effect guaranteeing loans and everything else. You are talking about guaranteeing the viablity of this project.

We have not had to do that in selling gas in the past, and it would not be our intention to do that at this time.

Mr. Dingell. I am curious. The question, as I understand it, was would you guarantee the delivery of two BCF. It wasn't would you guarantee financing and other things.

Mr. Rawl. Congressman, what do you mean 'guarantee'?

Mr. Dingell. Guarantee delivery of gas.

Mr. Rawl. Let's say the field then because of state action or regulatory action by the state oil and gas commission, they decide----

Mr. Dingell. I can't guarantee what any state is going to do.

Mr. Rawl. But you are in this case, sir, because if they tell us all ~~yu~~ you can produce is only 1.8 billion----

Mr. Dingell. You are talking about them imposing allowables.

Mr. Rawl. Yes, sir, something of that sort.

Mr. Dingell. Within that bounds, I think--with that reservation--why don't we phrase the question differently and say could you assure two BCF.

Mr. Rawl. I think we can assure it. But if some external force prohibits us from delivering, and that has happened in places----

Mr. Dingell. Let me explain the reason for the question of counsel. We have over the years had great controversy, as I am sure you are aware, over the fact that the contracts would provide for delivery of a given amount of gas, which would not be equaled over the life of the contract.

I think the question relates to the question of whether in point of fact two BCF would come into the pipeline on a daily basis.

Is there any controversy over that point, that we could be assured that on a daily basis two BCF would enter at least the northern end of the line?

Mr. Rawl. Yes, sir, I think you can be assured of that. But the word 'assurance,' based on all the technical knowledge and know-how and so forth, and external factors you have to take into account here, is a lot----

Mr. Dingell. If you have an earthquake up there or something of that sort, it is pretty clear to me that two BCF is not going to be going into the line.

Mr. Rawl. When you say guarantee, I felt like you are talking about that as if gas doesn't flow, we end up paying the tariff for nonflowing gas.

Mr. Dingell. Counsel advises me he was not contemplating financial guarantee in this.

Mr. Rawl. Contemplating a throughput guarantee, though, which in effect--Mr. Gammage talked about that, in terms of undergirding bonds for the State of Texas, you just cannot guarantee throughput. We can assure you that based on our studies, and studies by others, and by the financial advisers of all of these projects, all three of these projects, and other projects in the state, that the gas is available and it should be reasonably expected that it will be two BCF or more for this project.

Mr. Dingell. Can you give us some judgment as to what is the minimum price that enables you to sell the gas of your three companies into the line? What is the price at the pipeline head up there at the northern end?

Mr. Goldsmith. Let me try that, if I might, Chairman Dingell.

We, of course, asked for natural gas deregulation. Let the marketplace decide. That is the easiest.

Mr. Dingell. I understand your position well. Although I disagree with it, I am not disposed to quarrel with you about it at this time.

Mr. Goldsmith. All right. Stepping from that, and looking at a regulated situation, we have asked that the price in Alaska be exactly the same as the Lower 48 states. There are three reasons----

Mr. Dingell. In other words, you are asking for the same prices as would be given in the Lower 48.

Mr. Goldsmith. Right. There are three reasons for that, sir. We have been talking about reservoir performance a lot today. Well, until you have lived with a new wife or lived with a new reservoir, you don't know what is going to be required to keep her happy, as I understand.

But, we could be forced to incur very substantial capital investments and operating expense costs to maintain the reservoir once gas is produced.

One possibility--and here I am getting into Mr. Bawl's field--water flooding is a possibility. That could be a very substantial cost.

The second reason that you need a legitimate gas price in relation to oil is the trade-off aspect between oil and gas as commodity values. To the extent that there has to be any sacrifice temporarily or otherwise of oil production for gas or gas production for oil, if they are valued roughly equal, on a commodity basis at the wellhead, those trade-offs can be made in the best interests of the consumer and the producers and the State of Alaska.

But, if they are artificially far apart, you cannot operate on an economic basis. You get into an adversary position with the State of Alaska and an adversary position even among the producers, who have differing ownership interests.

Mr. Dingell. Now, there has been the question raised from time to time about state and local taxation, things of that kind.

Are there any comments that you might make about the adverse effect of state and local taxation on this natural gas in Alaska, which might jeopardize the project either from the production end or from the transportation end?

Mr. Goldsmith. If we had an artificially low price for the gas the State of Alaska would feel they would be mistreated by the Congress or by the FERC, and they would consider some of the same actions considered in the case of oil, by excessively taxing the oil.

Mr. Dingell. I am talking about things like boroughs, which would impose taxes on land up there.

Mr. Goldsmith. Excessively tax the gas. I would not expect, if the State of Alaska receives the same price at the Lower 48, that the State of Alaska would tax us any different than the Lower 48 states.

In fact, as I understand the position of the Commissioner of Revenue and the Governor of the State of Alaska they will tax equal to the highest state in the Union, but not greater than that. But, that assumes they are getting a fair price to begin with.

Mr. Dingell. Gentlemen, Mr. Rawl, or would any of our other panel members like to make a comment on that particular point?

Mr. Rawl. Mr. Chairman, I am very reluctant, of course, to discuss price with a couple of competitors sitting here. I Don't think I am in a position to forecast what the costs will be and how you allocate costs.

This is a typical butcher shop type of thing, only it is the largest butcher shop we have ever done business in, in terms of allocating costs. But, I will say that I do feel that

Alaska should not be discriminated against in terms of whatever legislation transpires.

Mr. Dingell. I have a curious position on discrimination. In all instances I am against it, whether it is for or against anybody. That goes to color of hide or where a fellow happens to live, sex, race, or anything else. So in that at least I think we agree.

Mr. Rawl. In terms of the taxing authorities up there, I would think they would be reasonable in that regard. They certainly have an interest, too, in seeing that this gas goes to market. They have some other problems, they would like to see ~~of it used interstate~~ some of the gas used in the state and so forth.

Mr. Dingell. Do you have any rason to assume superboroughs might come into being with monstrous taxes being imposed on the product of the whole North Slope, or something of that kind?

Mr. Rawl. I have no reason to believe that.

Mr. Dingell. Do any of you gentlemen have that concern? We have not heard from you, Mr. Miller.

98-069 O - 78 - 46

Mr. Miller. I will comment on both of those issues, if you would like.

On the first one, the price allocation is a very difficult thing, particularly the regulatory work and uncertainty we are dealing with. But I think as a general matter whatever price is established has to be looked at in the context of the overall economics of the project, so that it is an economically viable project, because that is something hat lenders are going to insist upon before they put any money into it.

Mr. Dingell. The question is at what point do these taxes and so forth convert this from a viable project to one which is not viable.

Mr. Miller. I am not sure what point that is. But in terms of the price that goes to each segment of this operation, I think you have to have a price and a return that will attract the capital into it.

In terms of the wellhead price, I think you have to give thought to what is going to be necessary to stimulate additional exploration and production on the North Slope.

If that price isn't deemed to be sufficient to spur that exploration and production, you are not going to get additional supplies developed. So, that has to be considered.

I think if that situation developed, where additional exploration, perhaps additional finds and then production, is part of the overall pricing philosophy, I think the state would be less inclined to be overzealous in their taxation policies.

If something was done to preclude additional exploration, and therefore deprive the state of additional revenue that might be generated by finding further supplies of natural gas or oil, perhaps they would try to offset that.

Mr. Dingell. I yield.

Mr. Roncalio. I thank you.

Gentlemen, I want to wrap up my feelings in this regard, to all three of you, and it is with every ounce of sincerity I have. I am a little surprised. I reread your statement but I think I sensed in the statements something less than enthusiasm over this choice. Yet I find Atlantic Richfield contributed money to help with the Trans-Alaskan originally, but the one you had not backed up, you feel like a fellow leaving a racetrack, you bet on a couple of horses and somebody else stepped in, and I sense that coolness in your feelings today.

In the common situation I have to state this, gentlemen: I hope whether you believe or disbelieve who got the thing, you recognize the vast importance to this government that this be completed. It is the President's choice. He picked it. Canada picked where it would go and the environmentalists picked in Alaska.

In this Congress we face very day almost like military bullets--I find deep resentment and animosity for the gas and oil industry. There are bills for divestiture, horizontal and vertical. There is a bill I just about killed last week by bringing out of the blue a motion to table, my chairman Mo Udall's bill to prohibit your company from having any OCS lease. I lost by three votes. I think he had some proxies in his pocket, but it was close, three votes.

Downstairs this morning I introduced two men from Wyoming, both in the uraniium filing business, with serious charges of almost criminal conspiracy towards McGee and Gulf Oil Company, two in your business, over what they allege to be improper fiings of uranium, thus conspiring you see to control all of the various types of oil, gas, uranium, and so on.

It is tough to have to fight this off day after day, weak after week, and to come up with something we can all live with, I think to see you progress, develop and go after the resources and bring them out and make it possible, and tax you and spend your taxes wisely. I understand that to e democracy.

It gives us political freedom, gives you econcmic freedom. I think it is the best system in the world, but I do not think we are moving in the right direction when I feel a little bit of hostility here towards the fact that there is a Group now ready to put out 10, 12, or $13 bilion to do this, and all they want is some sign that you might sit down with them and let them help you make 25 or $30 billion more than you are gong to by moving your product to the market.

I make my point with a degree I hope of friendship. I worked for your company. You hired me when I lost my Senate race, and for four years I got you good rates in the field on secondary recovery. You have problems, not with me. I am leaving here in a year. You have to understand that.

In three different places hostilities are towards the oil company; downstairs, the uranium hearings, Mr. Moss, here, and in Interior on divestiture.

John Bingham will have one in a few months that is even stronger. It is the balance trying to move in the right direction and keeping 220 million people reasonably happey. That is our problem.

I would like a little bit of a response.

Mr. Miller. I did not get an opportunity earlier to comment on whether or not we were disappointed with the selection. You seem to feel that perhaps that had a bearing on what we had to say here today. I can assure you in Sohio's case, and I suspect in the other two, it did not. We do not perceive significant differences in terms of what our realization is going to be with any of the proposals that were advanced, such that we felt any disappointment in terms of whatever proposal was selected.

I think the one that we would endorse, support, and would hope would move forward is the one that could get us into production as soon as possible, but I think we would still be here regardless of what choices were made in that regard, because there are some fundamental issues here that do not relate to the selection of a project out of the three.

All three of them are involved with moving gas from a remote area to a very expensive pipeline, regardless of which one was selected or which system was selected to a regulated market, where prices are artificial. I think that is the fundamental underlyng difficulty, and our enthusiasm would probably not be any greater had another project been selected.

Mr. Roncalio. I thank you very much.

I heard each of you sort of criticize Alcan. Maybe Alcan is still busy pinching themselves. They have only been notified for a couple of weeks.

Mr. Rawl. With all due respect, I did not criticize Alcan. I am probably unemotional enough to not express my enthusiasm, but as I said in my statement, we are just delighted that there is a project, and that the administration supports the project.

Mr. Roncalio. Thank you very much. I appreciate it.

Mr. Goldsmith. Could I also respond to your comments, and I thank you for them.

Please let me correct any impression that I was criticizing Alcan or thinking it was the worst of the three alternatives. We do not. We are most concerned about having the project approved, that is in the most expeditious and best interests of the public. Alcan has been selected on that kind of criteria.

My only displeasure has been one of this attempt to extort producer involvement, and the atmosphere, as you have pointed out, sir, from your excellent remarks about what is happening in Washington today with the oil industry; the threat of divestiture, especially, is the very kind of atmosphere in which one could not prudently invest the shareholders' money in a pipeline investment.

Mr. Roncalio. I understand loud and clear.

Thank you very much, Mr. Chairman.

Mr. Dingell. Gentlemen, thank you all. You have been patient and we thank you for your assistance. You have helped us greatly, as my good friend indicates. Thank you all for your presence here. I think you agree that it has been at least a useful meeting.

The subcommittee is not in order. We do again remind our guests that this is a meeting of a congressional committee and it is the duty of the Chair to keep order, which I fully and vigorously intend to do. I would suggest that all who wish to converse should do so elsewhere.

ATTACHMENT F

RESPONSES TO ENERGY COMMITTEE STAFF/GAO QUESTIONS
CONCERNING THE PRUDHOE BAY RESERVOIR

1. Will the produced gas available for sale be solution gas or gas cap gas?

   Answer: Both solution gas and gas cap gas will be available for sale. The relative amounts of each produced to meet sales will vary with time.

   Gas sales from the Prudhoe Bay field are expected to begin 6 to 7 years from now. By the time gas sales begin, over 2 Tcf of solution gas will have been reinjected and additional solution gas will have been liberated in the reservoir. For these reasons, with a gas sale of 2.0 Bcf per day beginning after 6 or 7 years, there will be no effective gas cap voidage for well over 10 years.

   As oil production declines and the amount of solution gas production decreases, the fraction of the sale resulting from gas cap gas production will increase.

2. Will the production from the gas cap or solution gas significantly lower the reservoir pressure?

   Answer: Gas sales of 2 Bcf/D as soon as a gas pipeline is available do not result in significantly lower reservoir pressure than deferring the same sales volume for an additional 10 years. The Prudhoe Bay field has a very large gas cap and is expected to have a limited water drive, the combination of which will offer substantial reservoir pressure support. Exxon presented testimony at the State of Alaska Field Rule Hearing in May 1977 which showed the sale of 2.0 Bcf per day after 5 years compared to no sales until 15 years reduced the average volume-weighted average oil zone pressure by only 10 percent, or about 300 psi. For this example, no additional water was injected in the earlier gas sale case which could have offset this pressure difference.

3. Is a water drive occurring?

   Answer: Based on extensive studies of the Sadlerochit aquifer, it is expected that the field will have a limited water drive. The field has just been placed on production so no physical evidence of water influx could yet be expected. The reservoir surveillance activities discussed at the hearings referenced above have been initiated to get an early verification of our projections.

4. Is a partial water drive occurring?

   Answer: See the answer to Question No. 3 above.

5. If a partial water drive is occurring and the reservoir pressure is declining, what are the plans for pressure maintenance?

Answer: Water injection plans were outlined in the State hearings referenced above. The injection of produced water will occur once the produced water volumes become significant, which we now estimate to be within 2 to 4 years after the start of oil production. We plan to inject this water in areas of the field where oil recovery under primary depletion would be the poorest. Such injection volumes will ultimately amount to over 500,000 barrels per day and total about 5 billion barrels. By this selective reinjection of produced water, we anticipate having a very effective waterflood.

Source water injection into the reservoir can begin when additional oil recovery benefits are confirmed and the optimum injection locations and volumes are determined. It is now anticipated that source water injection will begin within about 7 years. In addition to the reservoir surveillance program, water injection tests are being designed and waterflood design and implementation studies are beginning to insure the timing required to achieve maximum waterflood benefits can be achieved.

6. Would declining gas cap pressure create a situation that would cause oil to be lost in the gas cap portion?

   Answer: No. Gas cap gas will expand well down into the oil rim during the 6 or 7 years of oil production prior to start of gas sales. In addition, over 2 Tcf of solution gas will be injected into the gas cap of the reservoir.

   This expansion and reinjection creates a gas-invaded buffer zone between the portion of the oil column that is waterswept and the original gas cap. This buffer zone will allow gas sales to occur without oil being lost due to migration into the gas cap.

7. Would partial water drives through a faulting system as described for the Sadlerochit reservoir bypass a considerable amount of oil if pressure-depletion methods were applied too rapidly?

   Answer: In no case can we envision overtaxing the combination drive natural depletion process to the extent that it causes a loss of oil recovery. The operating plan has been designed with the flexibility to vary the offtake and injection rates and locations to minimize the possibility of bypassing oil.

8. Would gas production without reinjection cause a premature oil decline?

   Answer: No. The onset of oil production decline is controlled primarily by the advance of the gas-oil contact. Increasing gas-oil ratios ultimately result in the gas-handling capability being exceeded, at which time oil production becomes limited. The advance of the gas-oil contact is related primarily to withdrawals of oil from the oil zone, and is only very slightly affected by gas offtakes since natural water influx is essentially the same with and without gas sales at the point of oil decline. Therefore, the timing of gas sales has very limited, if any, measurable effect on the timing of oil production decline, assuming gas handling capability is equivalent in either the case of sales or no sales.

9. How were the maximum production rates for oil producers determined?

   Answer: Individual well rates were determined using radial well models designed specifically to evaluate the possibility of prematurely coning gas and water into the wellbore. These models are now being used to minimize these potential problems by optimizing standoff distances between the perforations and the gas-oil and oil-water contacts and taking maximum advantage of protective shale members.

10. Does the water production indicate that a natural water drive is occurring?

    Answer: As discussed in Question No. 9 above, perforation intervals are designed to minimize gas and water production. At this very early stage of field production, there is not sufficient water production to make any judgments regarding the natural water drive.

11. What cost benefits would occur from a natural water drive mechanism as opposed to the installation of a secondary recovery system?

    Answer: If the two systems were equally effective, there would be cost benefits associated with natural water drive. However, as discussed in the preceding questions, the natural water drive is expected to be limited and produced and source water injection programs are being considered to augment natural water influx. In the "Technical Considerations, Prudhoe Bay Unit Operating Plan" report submitted by the field operators to the State of Alaska on October 20, 1976, it was stated that the source water injection project would cost over $1 billion.

12. Would following normal recommended engineering practices dictate that a pressure maintenance system not be designed or installed until sufficient production and pressure history data has indicated which water drive mechanism is occurring?

    Answer: No. Modern reservoir performance evaluations include studies of the aquifer in order to obtain an early indication of its probable effectiveness. The timing for start of waterflood design studies and implementation must be considered on a reservoir-by-reservoir basis. In the case of Prudhoe Bay, the major reason for considering water injection is not pressure maintenance, but improved conformance or sweep efficiency in areas of the reservoir which experience inefficient recovery under the natural depletion process.

    Because of the complex nature of the field, the selection of the optimum well locations and injection volumes will require field production performance and testing data. The decision has been made to proceed with waterflood design and implementation studies concurrently with reservoir data gathering so that a waterflood can be initiated as soon as practicable when benefits have been confirmed and optimum locations and volumes have been selected.

13. Would gas cap withdrawals be contrary to normal engineering practices?

 Answer: No, simultaneous gas cap withdrawals and oil production is quite normal practice in many fields. There is no general conclusion which can be drawn regarding the advisability of producing gas cap gas concurrently with oil production. Operating plans must be developed for each reservoir based on the individual characteristics of that reservoir. For instance, if the reservoir had a strong water drive and successful replacement of voidage from the gas cap could not be accomplished, the offtake of gas cap gas would not be advisable because oil could migrate into the gas cap resulting in some loss of oil reserves.

 The characteristics of the Prudhoe Bay field make it possible to sell gas as early as a gas pipeline system can be installed consistent with sound engineering practices. There are several reasons why gas sales at Prudhoe Bay will not affect oil recovery:

 (1) The earliest possible gas sales date is about 6 to 7 years from now. At that time, approximately one-third of the recoverable oil will have been produced. Obviously, this oil cannot be affected by gas sales.

 (2) With gas sales beginning after 6 to 7 years, there will be no effective gas cap gas voidage until after 10 years of oil production.

 (3) During the early years of production, the gas will move considerably into the oil zone due to gas reinjection and gas cap expansion. This expansion of the cap minimizes concerns about oil migrating into the gas cap.

 (4) Our model studies indicate that the sale of gas in 1983 as compared to 1993 has only a slight effect on average depletion pressure. (10% or about 300 psi.) The relatively minor effect of this pressure difference can be offset by water injection.

 (5) Fluid properties of oil at Prudhoe Bay are not very sensitive to pressure over that 300-psi range.

14. What is the reservoir practices in the Cook Inlet oil field area? Are reservoirs in that area similar to the Prudhoe Bay reservoirs?

 Answer: Exxon has no operations in the Cook Inlet and as a result cannot comment on this question.

15. What was the total estimated oil production from the Sadlerochit reservoir upon which you based your proposed tariffs to the ICC?

 Answer: As documented in Exxon Pipeline Company's letter dated April 27, 1977, to Mr. John Grady, Director - Bureau of Accounts, Interstate Commerce Commission, 9.6 billion barrels of liquid hydrocarbon recoverable reserves were used as the basis for calculating Exxon's initial tariff rate.

16. Can the estimated 400 million barrels of natural gas liquids to be produced from Prudhoe Bay be transported to markets via the Alyeska oil pipeline?

Answer: It is anticipated that the gas purchasers will remove gas liquids from the Prudhoe Bay gas only to the extent necessary to meet the hydrocarbon dew point requirements of the gas pipeline.

The volume of natural gas liquids cannot be determined until gas pipeline specifications are known.

It is contemplated that practically all of the propanes in the gas could go into the gas pipeline stream. Essentially all the iso-butanes and some of the normal butanes could be used for fuel.

It is anticipated that all the NGL's not used as fuel will be blended with the crude oil and shipped through the oil pipeline.

In any event, it is anticipated that all gas liquids removed from the gas as a condition for meeting gas pipeline specifications can be used for beneficial purposes.

17. If a waterflood using water from outside sources is not inaugurated, because it is not deemed to be economically viable, can the initial 2.0 Bcf/D rate be sustained for the life of the field?

Answer: Whether a waterflood system is initiated or not has very little effect on the deliverability of gas from the field.

ATTACHMENT G

EFFECT OF GAS OFFTAKE ON OIL RECOVERY MAIN AREA SADLEROCHIT RESERVOIR PRUDHOE BAY FIELD

The effect of gas offtakes on oil recovery has been the subject of much study by the owner companies and others. The 26 trillion cubic feet of Prudhoe Bay gas reserves have the energy equivalent of approximately 5 billion barrels of oil, or over one-half the crude oil reserves. Because the gas at Prudhoe Bay is such an important energy resource, development of a plan for its production, consistent with good conservation practices, has been a major objective of Exxon's reservoir performance studies.

There are important advantages for the simultaneous production of oil and the sale of gas, including:

(1) Improved operating and cost efficiency since the facilities for handling the oil can be used for handling gas which will allow oil production to lower economic limiting rates.

(2) Reduced fuel consumption with savings possibly amounting to the energy equivalent of 100 million barrels of oil.

(3) Added gas liquids recovery because it is necessary to blend such liquids with crude for shipment with the oil production. Ultimately, it is expected that 300 to 400 million barrels of gas liquids will be extracted.

The attached chart summarizes the results of a number of sensitivity studies conducted by Exxon which show that the operators can efficiently manage the reservoir with early gas sales.

The first two cases shown are cases with produced water returned to waterflood the lower portion of the reservoir. In the first case, 2.0 Bcf/D of gas pipeline deliveries were delayed until 15 years after the start of oil production. In the second case, the same volume of gas was sold at the earliest possible date, about 5 years after the start of oil production. Although the difference observed can be offset by changing other variables, the oil recoveries differed by only 1.3 percent and this can be attributed primarily to pressure differences. The volume-weighted average oil zone pressure was reduced by 318 psi (or less than 10 percent) for the year 5 sale vs. the year 15 sale. As stated above, additional studies demonstrate this small reduction in oil recovery can be compensated for by modifying one or more operational factors, such as water injection.

The remaining cases on the chart all have source water injection programs. The third case has 2.0 Bcf/D of gas pipeline deliveries delayed until 10 years after the start of oil production with source water injection commencing after 7 years with a peak injection rate of 2.0 MMB/D. The fourth case has gas pipeline deliveries of 2.0 Bcf/D after 5 years with a waterflood program identical to the third case. The fifth case also has 2.0 Bcf/D gas pipeline deliveries after 5 years and source water injection commencing after 7 years with a peak injection rate of 3.5 MMB/D. Cases three through five indicate that an ultimate oil recovery in the order of 40 percent is attainable with gas sales commencing 5 and 10 years after the start of oil production.

Enclosed with this submittal is a copy of Exxon's testimony before the Alaska Oil and Gas Conservation Committee at the public Pool Rules hearing conducted in Anchorage on May 5 and 6, 1977.

SENSITIVITY TO GAS OFFTAKE RATES AND TIMING
MAIN AREA SADLEROCHIT RESERVOIR

Operating Parameters Held Constant

1.5 MMBOPD
160-acre well spacing
Low pressure and artificial lift

Gas Pipeline Deliveries		Water Injection		Average	Oil Recovery
Year*	Bcf/D	Year*	MMB/D	Pressure**	% 00IP
15	2.0	Produced only	0.6	3602	37.5
5	2.0	Produced only	0.6	3284	36.2
10	2.0	7	2.0	3693	40.0
5	2.0	7	2.0	3454	39.3
5	2.0	7	3.5	3686	40.2

* Years after start of oil produciton
** Average depletion pressure (psi)

10/28/77

DIVISION OF OIL AND GAS CONSERVATION HEARING

PLAN OF DEVELOPMENT AND OPERATION

PRUDHOE BAY (PERMO-TRIASSIC) RESERVOIR

PRUDHOE BAY UNIT

Anchorage, Alaska

May 5, 1977

EXXON RESERVOIR MODEL STUDIES

Members of the Alaska Oil and Gas Conservation Committee, ladies and gentlemen, my name is Alan Justice. I received a Master of Science Degree in Civil Engineering from North Carolina State University in 1966 and was employed by Exxon Co., U.S.A. during that year as an Associate Engineer. Since that time I have had a variety of Production Department assignments.

I have worked in the field of Reservoir Engineering for the past eight years and have been supervising Exxon's Prudhoe Bay Reservoir Engineering studies since October, 1972. I am currently Division Reservoir Engineer for Exxon's Western Production Division.

1. Reservoir Description

a. I plan to discuss Exxon's reservoir model studies of the Sadlerochit Reservoir of the Prudhoe Bay Field.

Mr. McIntosh reviewed the geologic structure and lithologic units of the Sadlerochit Reservoir and Mr. Creveling summarized the high specialized analyses of basic core and log data used to determine in-place hydrocarbon volumes. Similar detailed engineering and geological analyses have been made to evaluate key reservoir properties which will influence field production performance. I would like to highlight Exxon's efforts regarding reservoir description before discussing the results of our studies, since reservoir description is the most important factor in developing accurate performance predictions.

b. Overview

Figure 1 is a type log (Well 33-11-13) of the Sadlerochit Sandstone interval showing the lithographic units, the gamma-ray and sonic log responses, and major correlatable shale members. The average rock properties give a good indication of the reservoir quality. These properties vary quite a bit throughout the reservoir as I will discuss later. Zone 1 consists of interbedded sandstones and shales. It averages 70 feet in thickness with porosity of 21.6% and permeability of 240 md. The large number of shales caused the low net-to-gross ratio of 73% and vertical-to-horizontal permeability, or Kv/Kh ratio of only 1%. Zone 2 is a series of much cleaner, more massive braided stream sandstones separated by major shale members.

These shales become more massive offstructure, as could be expected with the source of deposition having been from the north. Zone 2 averages 250 feet in thickness with an average porosity of 24.7% and permeability of 660 millidarcies. Note that the shale content has decreased markedly compared to Zone 1, resulting in a net-to-gross ratio of 88% and a Kv/Kh ratio averaging about 15%.

Zone 3 is a conglomeratic interval averaging 70 feet in thickness. This interval was deposited in a high energy stream environment and is characterized by poor sorting, with grain sizes varying from very fine sand to large pebbles. Because of the large pebbles, porosity is low, 17.8%, but permeability is quite high, over 900 md. There are very few shales in this interval such that the N/G ratio averages 98% and the Kv/Kh ratio is excellent, averaging 39%.

Zone 4 is a uniform fine-grained sandstone containing a number of small shales. This sand averages 160 feet thick, has a porosity of 24%, permeability of 260 md, net-to-gross ratio of 89%, and a Kv/Kh ratio of 12%. The variation in rock properties between the lithologic zones complicates fluid flow and results in substantially different performance between zones. This, of course, makes the prediction of performance quite complex and is a major reason why sophisticated numerical simulation studies are necessary.

As noted on the log, there are numerous minor shales which, as I will discuss later, have a big influence on effective vertical permeability and in turn on reservoir performance. Also noted on the log are four major shale complexes which have been identified as existing over large areas of the Reservoir. Shale A is near the top of Zone 1; Shale B appears at about the middle of Zone 2; Shale C is encountered in the upper 1/3 of Zone 2; and Shale D is located near the base of Zone 4. These shales are not continuous over the entire reservoir, but they have been correlated between wells over wide areas. These shales further complicate reservoir performance predictions in that they can result in the lithologic zones acting somewhat independently of the others.

This map shows the areal extent of the uppermost correlatable shale, Shale D. The productive limit of the Sadlerochit Reservoir is shown by the dashed line. The shale, shown in the darker shade, is continuous over the eastern 1/4 of the oil column and also covers a large area near the middle of the reservoir. In total, the D shale underlies almost 1/2 of the oil in place in Zone 4. Because of the influence this and other correlatable shales will have on reservoir performance, we have constructed our models so that these shales can be described as impermeable barriers to vertical flow.

Although we can correlate these shales from well to well, in a braided stream environment it is possible that stream scouring could have caused breaches of the shales between wells. The monitoring of pressures and gas-oil contact movement after production start-up and the drilling of additional wells on closer spacing should provide early indications as to shale continuity.

d. Development of Rock Properties

Both core and log data were utilized extensively to determine the variations in rock properties throughout the reservoir for use in our model studies. Over 9000 core samples have been taken from about 40 wells throughout the field. These core samples have undergone routine lab analysis for porosity and horizontal and vertical permeability. Special tests were also conducted on selected core samples for evaluation of relative permeability and capillary pressure relationships.

e. Porosity

To determine porosity distribution, relationships between core and log data were developed to extrapolate the core data to all wells in the field. Correlations between core porosity and sonic log transit time were first developed for each lithology and each fluid type. Porosity was next determined for each lithology in each well on foot-by-foot basis.

Isoporosity maps were then constructed for each lithology and each indicated some degree of downstructure degradation in porosity, consistent with sediment deposition from a northern source.

f. <u>Horizontal Permeability</u>

Core data were also utilized to develop permeability-porosity relationships so that permeabilities could also be calculated from logs. Foot-by-foot permeabilities were calculated for each well and then averaged by zone. Zonal isopermeability maps were next constructed from the log-derived values. Permeability data were also developed from pressure build-up tests and these results generally agreed with the log-calculated permeabilities.

This figure shows the permeability distribution in Zone 4. The permeability ranges from a high of 700 millidarcies at the top of the structure to 50 millidarcies and less off-structure and averages 260 millidarcies. From a reservoir performance viewpoint, permeability variation can be as important as the absolute level of permeability. For this reason, we developed porosity and horizontal permeability maps similar to this for each lithology. For our model studies the four lithologies were further subdivided into a total of 14 layers and porosity and permeability values were determined for each.

g. Vertical Permeability Evaluation

We have devoted considerable effort to analyzing the effect of minor, noncorrelatable shales on vertical flow. To determine their effect, it was first necessary to determine shale frequency and shale size. A statistical analysis of the log data was made to estimate shale frequency. As determined by log analysis, Zone 1, the bottom-most interval, contains approximately eight shale intervals per well on the average; Zone 2 contains about nine; Zone 3, the conglomerate interval, averages only one such shale per well; and Zone 4 contains between 10 and 11. The number of shales were correlated to N/G ratio, so that the field-wide variations in shale frequency could be determined.

An estimate of the areal extent of the individual shales was based on a geologic study of modern-day stream environments, core analysis, and average shale thickness. This study found that, on an average, the stream channel width is about 40 times the channel depth and that shales deposited in such streams have average length to width ratios of three.

At the time of deposition of the Sadlerochit, the average channel depth was estimated to be about two feet based on sedimentary cycle analysis of Sadlerochit cores and average shale thickness. Therefore, it could be expected that the minor shales have an average width of about 75 feet and an average length of slightly over 200 feet.

With this description of the shales having been completed, the three-dimensional computer model shown schematically on this Viewgraph was used to determine vertical-to-horizonal permeability ratios for each lithology. A total of 28,500 grid blocks were used in the model. By flowing fluids through the model with and without the minor shales, it was possible to evaluate the effect of the shales on vertical flow as well as the sensitivity of vertical permeability to shale size and distribution. To give you an example of the effect of the shales, Zone 4 Kv/Kh ratio was reduced from 60% 12%.

This analysis has provided, in our opinion, the best estimate of effective vertical permeability which can be made prior to production. Additional drilling, field testing, and production performance will provide early verification of this key parameter.

h. Aquifer Description

The next Viewgraph shows the aquifer properties and volume and the location of wells from which data were available. A total of 26 wells have penetrated the Sadlerochit aquifer over a wide area, giving good data coverage. Approximately 900 feet of core data have been obtained from ten of these wells.

Although the aquifer covers a large area, net sand thickness and rock properties degrade rapidly offstructure. As shown in the inset, only 400 billion barrels or 35% of the aquifer volume is in rock which has permeability greater than 12 millidarcies. Thus, even though the total volume of 1.15 trillion barrels seems large, the effective portion is much smaller, so natural water influx is expected to be limited. Production performance data to be obtained through the reservoir surveillance program will provide the additional information needed to more accurately quantify aquifer response.

i. Fluid Properties

This map shows the location of wells from which crude and gas cap samples were obtained. A total of 33 crude samples from 14 wells and seven gas cap gas samples from two wells have been analyzed in the Main Area.

Initial reservoir pressure in the Main Area ranges from 4335 psia at the gas-oil contact to about 4480 psia at the water-oil contact.

The initial fluid properties in the Main Area are shown on the inset. Oil gravity in the "light oil" column averages slightly over 27° API, varying from 30° API at the gas-oil contact to about 26° API at the top of the heavy oil/tar zone. The oil formation volume factor averages 1.36 RB/STB and varies from about 1.4 to 1.3 RB/STB while oil viscosity averages about 0.8 centipoise and varies from 0.5 to 1.2 centipoise. Solution gas-oil ratio averages about 750 SCF/STB, varying from 900 to 700 between the gas-oil contact and the heavy oil/tar zone.

An initial gas cap condensate yield of about 35 barrels million cubic feet is expected from the separators located at the flow stations and gathering centers. In addition, it is expected that once gas sales begin, 10-15 barrels of gas liquids]er million cubic feet will be extracted at the gas sales conditioning plant to make the gas acceptable for pipeline delivery.

Fluid properties of the heavy oil/tar zone are also important considerations in the analysis of reservoir performance. This zone, the thickness of which is shown on this gross isopach map, is located just above the water contact in the Main Area. As shown, it varies in thickness from 20 to 70 feet, being generally thinner in the southeastern third of the field. Only very small amounts of oil were produced in tests of this zone with the oil having gravities less than 15° API. Core analysis indicates the zone has a permeability to brine of approximately one millidarcy. Model studies have indicated that although the heavy oil/tar zone will initially restrict aquifer influx, its effect on total ultimate water influx will be relatively minor. The heavy oil/tar zone could, however, have a significant effect on water injected below it, injectivity into it is reduced, and there is the possibility of nonuniform water influx due to its avrying thickness. The injection tests and reservoir surveillance programs we are planning will provide the information to evaluate the impact of the heavy oil/tar zone on water influx and water injection performance.

j. Saturation Functions

Extensive laboratory testing has been conducted to evaluate relative permeability and capilliary pressure relationships. The basic gas-oil relative permeability curves used in our reservoir studies, as shown on this Viewgraph, were determined by gas flooding composite cores and by centrifuging core plugs. The equilibrium gas saturation below which gas is immobile is shown to be about 3.5%.

Oil-water relative permeability data were obtained from waterflood tests run on composite cores and from centrifuge data. Waterflood relative permeability data were taken on preserved cores at reservoir conditions using reservoir fluids. Special care was taken during coring and testing to ensure the reservoir wettability conditions were not altered.

Three-phase relative permeability values were determined from two-phase laboratory data by use of empirically-derived probability models. Also, hysteresis was considered to account for the history-dependency of these functions. To develop the hysteresis functions, bounding curves for the gas-oil and water-oil drainage and imbibition systems were first developed from core analysis. Then scanning curves describing the transition from the drainage to the imbibition curves were generated based also on laboratory-derived data.

This Viewgraph shows an example of how hysteresis is used for determining relative permeability at a given grid block in the model. Shown is the relative permeability to water in an oil-water system. At initial conditions, the primary drainage Krw curve is utilized because the oil was emplaced into the reservoir under drainage conditions.

If the water saturation increases, the curve scanning back to the imbibition curve will be used as shown on this example. This history-dependent technique establishes the proper initial saturation relationship for each grid block. The saturation history of each block is also retained such that consideration can be given to the effect of trapped gas saturations on waterflood performance.

Although extensive, sophisticated laboratory analyses have been conducted and utilized in the model studies, actual field data will provide us the best measure of relative permeability. Therefore, we plan to analyze field production performance and well tests to confirm the laboratory-derived data.

2. Reservoir Studies

a. Models Utilized

During our studies of Sadlerochit reservoir performance, we have used a number of special purpose reservoir models to aid in developing an operating plan.

Two-dimensional areal models were used for evaluating aquifer performance. With these models it was possible to determine the sensitivity of its performance to variations in rock properties and size. These studies indicate that pressure support from the aquifer will be limited, resulting in rapid expansion of the gas cap into the oil rim.

Finely gridded two and three-dimensional models were utilized to confirm that the grid block sizes used in the field-wide models were small enough to represent the displacement process and were not being affected by numerical dispersion. Buckley-Leverett calculations verified the accuracy of the model's displacement calculations also.

Radial models for a variety of well descriptions were used to predict near wellbore flow effects including gas and water coning. These models indicated that in the absence of protective shales, the wells will have the tendency to cone gas and water due to the relatively high vertical permeability of the reservoir. The results of the radial well model studies were used to help select perforation intervals in the existing wells. The intervals being used have rather large standoff distances, especially from the gas which, due to its high mobility, will tend to cone greater distances than water. The radial well model results were also utilized to develop well performance functions for our field-wide three-dimensional model.

We have used field-wide two-dimensionsal, three-phase, cross-sectional models for our basic studies of long-range performance and for evaluation of overall reservoir management options.

Cross-sectional models were chosen for studies of reservoir management alternatives because the most significant and abrupt changes in Sadlerochit rock properties occur in the vertical section and with structural position, and vertical flow and gravity drainage dominate.

b. Description of the Cross-Sectional Model

Our current cross-sectional model has evolved from some seven years of work with earlier cross-sectional models. During this time we have developed techniques which allow us to include the effects of the reservoir properties and operational factors which are expected to affect reservoir behavior.

By nature, however, a cross-sectional model represents a simplication of the reservoir complexities. To assure ourselves that the cross-sectional model was providing valid results and to analyze areal variations in reservoir performance, we developed a three-dimensional model based on the same reservoir description as used in our cross-sectional models. The 3-D model verified the results of the cross-sectional model for both primary depletion and secondary recovery plans.

One of the key reservoir description parameters considered in developing our cross-sectional model was the major, correlatable shale complexes which were described earlier. In order to better represent such shales, our cross-sectional model consists of two wedges; one representing the less shalely half of the reservoir and the other representing the half which contains extensive shales. The two halves are connected so that flow may occur between them. The model was constructed to be wedge-shaped in proportion to the dimensions of the reservoir. In this manner, rock types, oil and gas in-place, and wells can be located consistent with the actual structure of the reservoir.

This schematic diagram represents the less shalely half of our cross-sectional model. The scale of the schematic is exaggerated 20 to 1 vertically to enhance the definition of the vertical section. Actual dip is only about 1.5°. The gas-oil contact in the model is at 8580 feet ss and the oil-water contact is at 9012 feet ss. Hence, the oil column thickness is 432 feet in those areas where both contacts exist. As you can see, at initial conditions the entire oil column is either overlain by gas or underlain by water, or both.

The model contains 60 grid blocks of 750 feet to 1000 feet length horizontally within the oil zone. Additional blocks, not shown on this Viewgraph, continue 70 miles downdip to represent the aquifer. Vertically, the model consists of 14 layers of variable thickness, representing the average thickness of each lithology at each structural position.

The heavy black lines represent location of the correlatable shales included in the model as no-flow vertical permeability barriers. Even though this is the less shalely half of the model, the shales are shown to become quite extensive offstructure. Further, there are extensive shales throughout the lower quarter of the reservoir.

The shaded area just above the oil-water contact represents the heavy oil/tar zone. Permeability in this zone has been reduced to 1 md based on core analysis results.

The columns containing X's represent producing wells. The locations shown represent 160-acre spacing within 100 feet of gross oil thickness. In total there are 13 well columns in each half representing 500 actual wells. Notice the completion intervals in the model have been selected with large standoffs from the contacts to avoid excessive gas and water production.

Well productivities in the model depend on the permeability and thickness of the completion interval and relative permeability relationship. To calculate productivity, a radial inflow equation is used which accounts for degradation of productivity due to gas saturation build-up around the well.

The equation is solved using an average wellbore damage ratio calculated from actual field tests. Well capacities are then calculated by simultaneous solution of the inflow equation and wellbore hydraulics which consider tubing size and two-phase vertical flow effects. Initial capacities in the model range from about 1800 B/D to approximately 20 MB/D per well.

This schematic diagram represents the more shalely half of our model. Notice the extensive nature of the "D" shale located at the base of Zone 4. Because this shale has more effect on gravity drainage and bottom water influx than any of the other major shales, it served as the key to our split between the two halves of the model. The other extensive shales were located in the model based on their position in the reservoir relative to the existence or absence of the "D" shale.

Completion intervals in this half of the model were designed to provide adequate drainage above extensive shales and to avoid gas which is overriding along the top of the sand and under the shales. In order to accurately reflect gravity segregation in the blocks overlying or underlying the shales, pseudo relative permeability functions were developed and used.

Water injection is potentially more beneficial to improved recovery in the shalier portion of the reservoir because the shales can be utilized to improve waterflood conformance.

In all cases with water injection, substantial volumes of water are injected into the lower third of the reservoir where shales are very extensive throughout the entire field. This section responds most favorably to water injection and is a potential location for the planned return of produced water.

In cases where produced water is supplemented by source water injection, two basic oil zone water injection plans are utilized. The first is a "flank injection" plan in which the most downstructure producing well column in each half of the model is converted to water injection to create a peripheral flood pattern. The second is an "updip injection" plan which is utilized only where the "D" shale is continuous. Injection wells for the "updip injection" plan are completed above the "D" shale near the GOC after adequate gas invasion has occurred to displace most of the mobile oil out of this updip area. Approximately seven years of production are necessary for this section to be adequately drained to allow for the optimum implementation of this type of plan.

In areas where the "D" shale is continuous, the updip injection plan is more efficient than the flank pattern. Since the success of such an injection plan depends upon the continuity of the shale, we plan to analyze production performance history and conduct special testing to verify shale continuity and to determine the feasibility of this type of injection program. In actual field operations, there will be additional alternative flood patterns which will need to be evaluated. This type of analysis will minimize the possibility that water will be injected into locations in the reservoir which could respond unfavorably to water injection.

3. Operational Constraints.

This Viewgraph summarizes the more important operational constraints imposed in the model. We impose field-wide limits for gas and water production rather than individual well limits since field facility limits will control rather than individual well GOR's and WOR's. Prior to gas sales, gas production volumes are limited to the planned injection capability of approximately 2.0 Bcf/D, plus field fuel requirements and equivalent condensate shrinkage. During gas sales, gas production volumes are limited to pipeline delivery rates plus fuel, liquids removal shrinkage, and carbon dioxide removal. Because of these factors, a pipeline delivery volume of 2.0 Bcf/D requires production of approximately 2.7 Bcf/D.

Water production is limited to 600 MB/D for natural depletion cases and 1 MMB/D for source water injection cases.

Well workovers in the model are performed as required to reduce gas or water production below the field limits if the workover increases oil rate by a specified amount and if it had been at least six months since the last workover on that well. If not, water and/or gas volumes are reduced to the field limit by restricting production from the highest water/oil or gas/oil ratio wells.

These operating limits were applied consistently and automatically in all our case studies. While somewhat simplified compared to the options available in making field operating decisions, the operating limits are consistent with plans for actual field operations.

4. Performance Characteristics

Before reviewing the detailed case results, I would like to highlight some general reservoir performance characteristics observed in our cross-sectional, radial well, and other model studies.

a. Natural water influx is expected to be less than required to fully maintain reservoir pressure due primarily to the degradation of rock properties that occurs with distance from the reservoir.

b. The dominant natural depletion mechanism is gas cap expansion/gravity drainage supplemented by solution gas drive and water influx. Gravity drainage is especially effective in areas with a thick oil column and good vertical permeability.

c. During early years of production, the gas cap expands moving vertically into the oil rim at a rate of about 25 feet per year and advancing horizontally to override much of the oil zone at the top of the sand and under continuous shale breaks. This early expansion of the gas cap minimizes concern that gas cap production will reduce ultimate oil reserves due to gas cap shrinkage.

I would like to demonstrate these first three points. This schematic diagram reflects the saturation changes that have occurred in the less shaley half of the model after 5 years of oil production. Blocks colored red reflect a 10% or greater increase in gas saturation and blocks colored blue reflect a similar increase in water saturation.

Note that water invasion at this point is quite limited and tends to be concentrated in the high permeability Zone 3 area. There is also evidence that the water is tending to cone vertically into the producing wells.

Gas invasion, on the other hand, is very pronounced, having moved over 100 feet vertically into the oil column and several thousand feet along the top of the sand. Also note the location of the produced water injection wells in the shalely lower quarter of the reservoir.

This diagram represents the shalier half of the model at the same point in time. The shales have tended to further limit water influx. Also, because the shales inhibit the gravity drainage of oil, the gas front has tended to override more severely, advancing much less uniformly than in the less shaley areas. It is behavior such as this that will provide us early clues as to the continuity of the major shale complexes and hence the need and best plan for water injection.

Continuing now with point 4 on the general reservoir performance summary:

d. Although completion intervals will be designed to take maximum advantage of shale production and standoff distance from the original contacts, gas and water coning will eventually occur over much of the reservoir. Significant volumes of gas cap will be produced through oil wells. If this gas is not delivered to a pipeline, it will be necessary to reinject an estimated 15-20 Tcf of gas into the gas cap. Although the return of such gas is not detrimental to reservoir performance, compression and injection of that gas would require the energy equivalent of more than 100 MM barrels of oil.

e. The onset of oil production decline is controlled primarily by the advance of the gas-oil contact. Increasing gas oil ratios ultimately result in the gas handling capability being exceeded, at which point oil production declines. Since the advance of the gas-oil contact is related primarily to net oil zone withdrawals, gas sales timing does not have much of an effect on oil production decline. There is some potential for delaying oil production decline by injecting source water to retard the advance of the gas-oil contact.

f. Studies indicate that the planned offtake of 1.5 MMBOPD can be sustained for about eight years of production.

g. The examination of a wide range of cases leads us to the conclusion that approximately 40% OOIp and 75% to 80% OGIP can be recovered from the Main Area Sadlerochit Reservoir.

5. Model Sensitivity Studies

Over the past seven years, we have analyzed numerous cases to evaluate the sensitivity of reservoir performance to controllable operational factors such as well density, artificial lift, water injection, and oil and gas offtake rates. We have also analyzed the sensitivity to potential variations in reservoir properties to ensure that our proposed plan of operation is feasible under any reasonably foreseeable condition. Looking first at the operational sensitivities:

a. Well Spacing

We have used model studies to evaluate the effect of well spacing on oil recovery. The current spacing order limits drilling to 320-acre spacing. A case with oil rates of 1.5 MMB/D, gas sales of 2.0 BCF/D after 5 years of oil production, produced water returned to the Sadlerochit, and the installation of low pressure and artificial lift systems indicated an ultimate recovery of 32.2% OOIP if only 320-acre locations were drilled.

By drilling additional wells to yield full 160-acre development, ultimate recovery was increased to 36.2% OOIP. The current spacing plan envisions drilling to 160-acre spacing within the 100 foot oil thickness contour requiring a total of over 500 wells. Additional infill drilling between 160-acre spaced wells in selected parts of the reservoir may occur, but these are long-range decisions which will depend upon observed reservoir performance.

b. Gathering System Pressure and Artificial Lift

Looking now at other operational factors which are necessary to achieve this 36.2% oil recovery, this Viewgraph shows the effect of installing low pressure and artificial lift systems. By installing low pressure gathering, separation, and compression equipment to reduce the wellhead flowing pressure from the initial system design of 800 psi to approximately 300 psi, ultimate oil recovery was increased by about 5% OOIP, from 26.3% to 31.6%. Installation of an artificial lift system along with the low pressure system increased oil recovery from 31.6% to the 36.2% OOIP previously described. Current plans are to install low pressure gathering and artificial lift facilities when needed to maintain established production rates. Decisions regarding the design and the timing for installation of these systems will be based on reservoir performance.

c. Produced Water Injection

This chart summarizes the potential benefits of utilizing produced water to waterflood selected areas of the reservoir.

The first case was run with no changes in the operational factors except that no produced water was returned to the reservoir. Due to the favorable rock properties which provide for good gravity drainage, the natural recovery mechanism is quite efficient, yielding an ultimate recovery of 34.2% OOIP.

By returning produced water at rates up to 600 MB/D to the Sadlerochit, ultimate oil recovery was increased by 2.0%, from 34.2% back to the 36.2% OOIP. For our case studies, this water was injected into the shaley lowest 1/3 of the reservoir where natural depletion recovery is the poorest. The current operating plan calls for the injection of produced water into the Sadlerochit within 2 to 4 years after the start of oil production. Total produced water injection volumes amount to about 5 billion barrels over the field life and represent a substantial waterflood program.

d. Source Water Injection Timing

Water injection case studies indicate potential for increasing oil recovery from 36.2% to a level of 39% to 40% OOIP by the implementation of a well designed source water injection plan. The earliest feasible implementation date for a source water injection project is approximately 3 years after the decision to waterflood has been made. At least 2 years of reservoir performance will be required in order to make responsible decisions regarding waterflood requirements. The time required to make decisions related to a source water injection program will depend to a large degree on the benefit to be derived from waterflooding. That is, if the need for waterflooding is great, the time required to observe that need will be less than if there is a small need. With this reservoir having a large gas cap to support pressure, with the natural depletion mechanism being very effective, and with a produced waterflood in those areas we expect to have poor natural depletion recovery, it is our opinion that time can be taken to obtain necessary data to make the proper decision regarding source water injection without reducing the oil recovery potential. The timing of decisions regarding waterflooding will likely vary from one area of the field to the next and any water injection programs will likely be in staged build-ups.

As indicated in this Viewgraph, our studies indicate ultimate oil recovery is not very sensitive to the timing of injection start-up. The later injection programs result in the same recovery if the rate of injection is increased to "catch up" with the earlier injection programs so as to ultimately achieve the same total volumetric conformance.

The first three cases which have source water injection beginning 5 to 9 years after start of oil production resulted in ultimate oil recovery of approximately 39%. Peak injection rates for these case varied from 1.7 to 2.5 MMB/D. The last two cases represent larger waterfloods, with peak water injection rates of 3 to 3.5 MMB/D beginning 5 to 7 years after start of oil production. Ultimate oil recovery of about 40% was achieved.

The difference in ultimate oil recovery among these cases is relatively small compared to the difference in the volumes of water injected. Increasing volumes of water injection yield diminishing benefits in terms of incremental oil recovery. For instance, increasing the injection rate from 2 MMB/D in the second case to 3.5 MMB/D in the last case increased oil recovery by 0.9%. On an incremental basis, it was necessary to inject more than 35 barrels of water for each additional barrel of oil recovered.

To summarize this Viewgraph, the major benefit in terms of additional oil recovery derived from water injection in the Sadlerochit reservoir is improved conformance. The selection of the optimum locations and volumes to be injected will be more of a key to the success of source water injection than the timing of start-up. Because of the complex and diverse nature of the field, selection of the optimum injection locations will require field production performance and testing data. Injection start-up commensurate with the time required to obtain this necessary information should not affect ultimate oil recovery. Based on these study results, the current operating plan for the field envisions source water injection programs being implemented when the need is justified and reservoir performance data better defines the optimum injection locations and volumes, currently estimated to be within 7 years after the start of oil production.

e. Oil Offtake Rates

This Viewgraph summarizes the effect oil oil offtake rates on oil recovery factors. Oil offtake rates were varied from 1.2 MMB/D to 1.8 MMB/D. Recoveries ranged from 35.9% OOIP for the 1.2 MMB/D rate to 36.2% OOIP at 1.5 MMB/D and 36.3% at 1.8 MMB/D. As shown, the recovery factors are essentially the same.

f. Gas Offtake Rates

The effect of gas offtakes on oil recovery has been the subject of much study by the owner companies and others. The 26 TCF of Prudhoe Bay gas reserves are equivalent to nearly 5 B bbls. of oil production, or over 1/2 the oil reserves. To assume that this gas would never be sold has not been a realistic option for consideration. Because the gas at Prudhoe Bay is such an important energy resource, development of a plan for its production, consistent with good conservation practices, has been a major objective of our reservoir performance studies.

The question of gas sales is really one of timing and there are many advantages for the simultaneous production of oil and the sale of gas:

(1) It provides for a substantially increased value for the Prudhoe Bay reserves being more efficient from a cost viewpoint since the facilities for handling the oil can be used for gas handling.

(2) The oil may be produced to lower ultimate rates if its associated gas production is being marketed.

(3) It saves fuel associated with the reinjection of gas.

(4) The 300-400 MMB of gas liquids removed in treating the gas for sales could more likely be transported with the oil production.

For these reasons, the optimum producing plan for the field involves the early sale of gas.

This chart summarizes the results of a number of sensitivity studies which have shown that the timing of 2.0 BCF/D gas pipeline deliveries does not significantly affect ultimate oil recovery under sound reservoir management plans.

The first two cases shown are cases with produced water returned to waterflood the lower portion of the reservoir. In the first case shown, 2.0 BCF/D of gas pipeline deliveries were delayed until 15 years after the start of oil production. In the second case, the same volume of gas was sold at the earliest possible date, about 5 years after the start of oil production. The 1.3% difference in oil recovery can be attributed primarily to pressure differences. The volume weighted average oil zone pressure was reduced by 300 psi (or less than 10%) for the year 5 sale vs. the year 15 sale. Additional studies, as shown by the remaining cases, indicate this potential reduction in oil recovery can be compensated for by modifying one or more operational factors, such as water injection.

The third case has pipeline deliveries of 2.0 BCF/D deferred until 10 years after the start of oil production and a peak water injection rate of 2.0 MMB/D beginning after 7 years of oil production. The final line summarizes several cases run with gas sales beginning after 5 years of oil production. Source water injection in these last cases was started 7 to 9 years after oil production start-up at maximum rates of 2.0 to 3.5 MMB/D. Under these conditions, ultimate oil recovery for cases with gas sales after 5 years is essentially the same as for the delayed gas sales case, ranging from 39.3 to 40.2% of the OOIP.

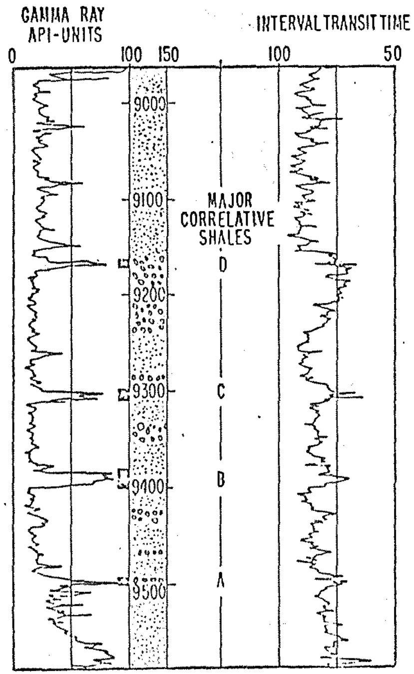
In addition to these operational sensitivities, we have investigated the sensitivity of the Prudhoe Bay operating plan to reasonable variations in key reservoir description parameters. These studies indicate that the proposed plan is feasible over a reasonable range of reservoir properties. However, certain operational factors, and in particular the optimum locations and volumes of water injection, may be different depending on the reservoir description.

This chart summarizes the incremental recovery attributed to source water injection programs compared to the return of produced water only, for several variations in the Sadlerochit reservoir description. The first case represents our current description which yields a 40% recovery with source injection versus 36% for no source water injection for an incremental of 4% OOIP. The next case is a low vertical permeability description in which natural gravity drainage is considerably less efficient. Under these conditions, oil recovery could be increased from 32% to 39% by source waterflooding. The third case shown represents the less shalely portions of the reservoir as we now model it. Under these conditions, the waterflood recovery is about 38% of the OOIP, compared to 36% for the produced water injection program. The last case represents the shalier half of the reservoir and demonstrates the potential effect of shale continuity on waterflood benefits. In this case, source waterflooding resulted in oil recovery of 43% compared to a produced water injection program of 37% OOIP. As indicated, the absence or presence of continuous shales can result in the benefits of waterflooding ranging from 2% to 6% OOIP.

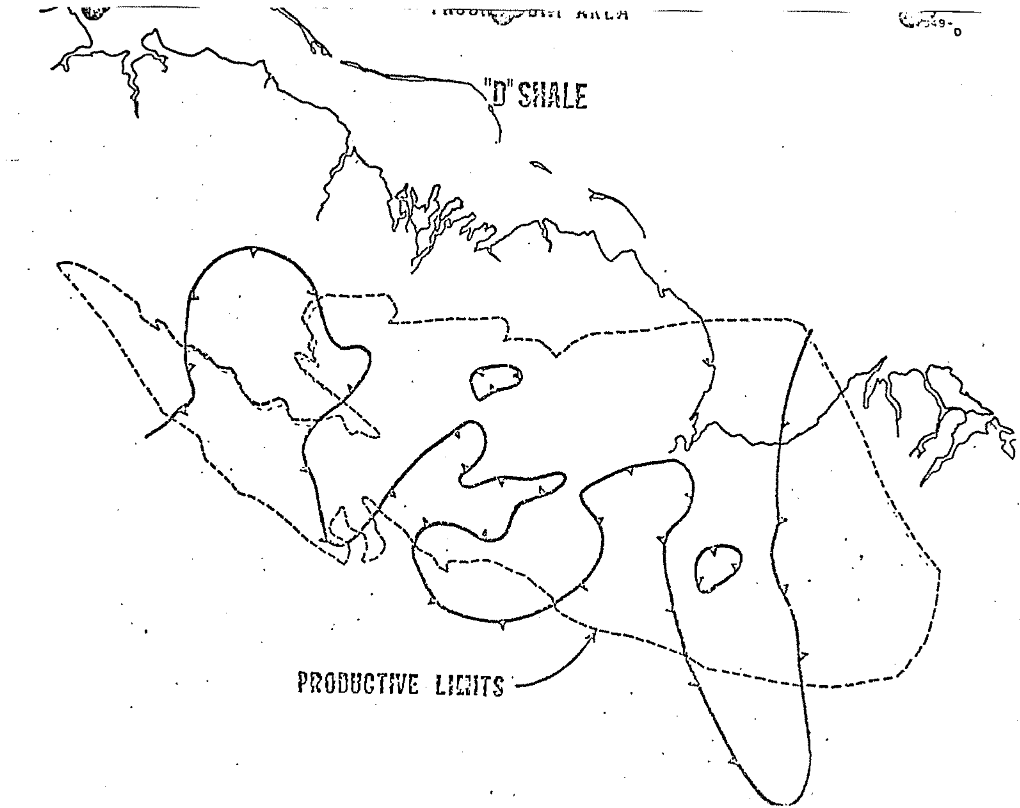
In summary, Exxon's reservoir studies support the proposed plan of operation for the Prudhoe Bay Field as previously outlined by Mr. Longwell. Because of its importance, this field has probably undergone the most extensive and complete reservoir study of any field in history prior to commencement of production. As additional data is gathered during production, reservoir performance studies will be carefully refined and updated to ensure maintenance of an optimum plan of operation for the field.

* * * * * * * *

PRUDHOE BAY
SADLEROCHIT FORMATION

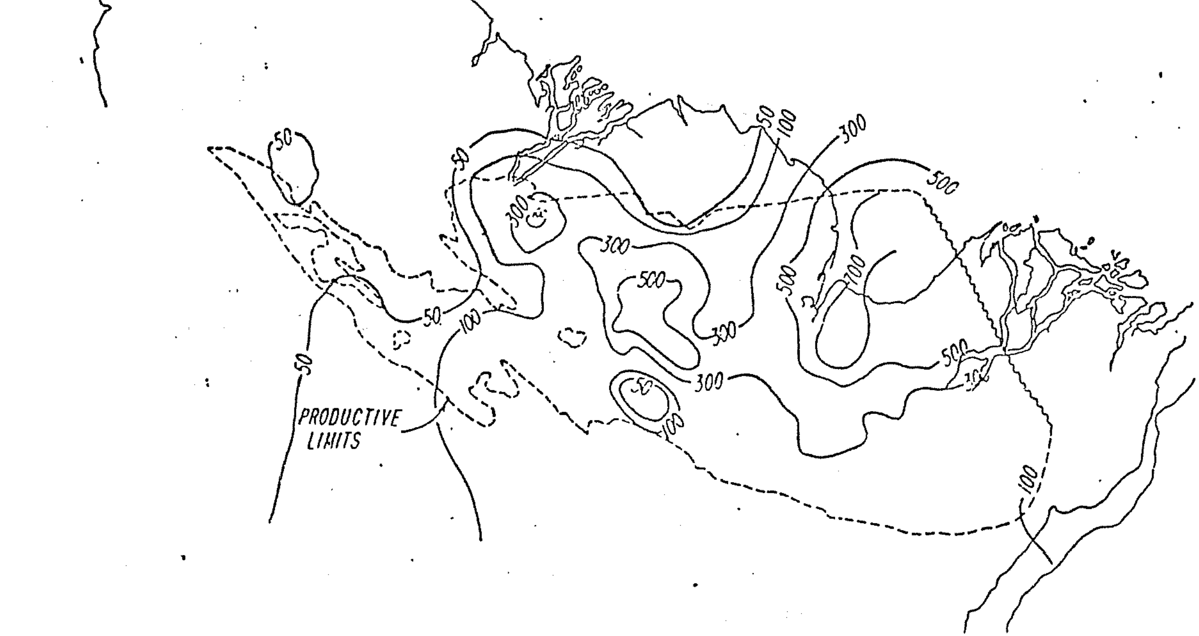


ZONATION GEOLOGICAL	AVERAGE PROPERTIES (OIL ZONE) H(ft.)	Ø (%)	K(md)	N/G Ratio	Kv/Kh
4	160	24.0	260	.89	.12
3	70	17.8	910	.98	.39
2	250	24.7	660	.88	.15
1	70	21.6	240	.73	.01


"D" SHALE
PRODUCTIVE LIMITS

2300-0

PRUDHOE BAY FIELD
SADLEROCHIT
ISOPERMEABILITY MAP
ZONE 4

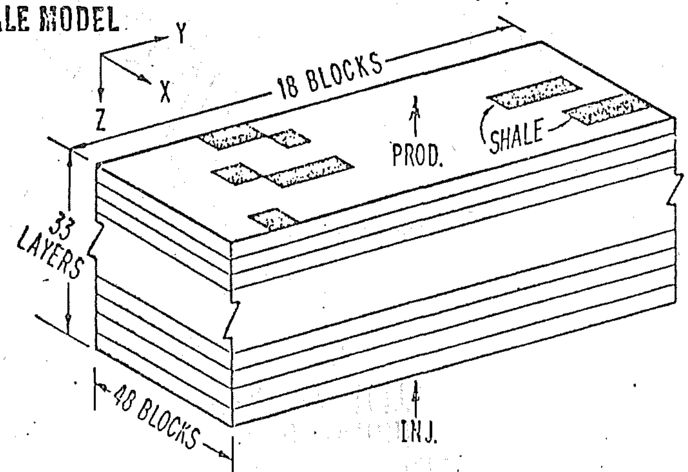


PRUDHOE BAY FIELD
SHALE EFFECTS ON VERTICAL PERMEABILITY
SADLEROCHIT RESERVOIR

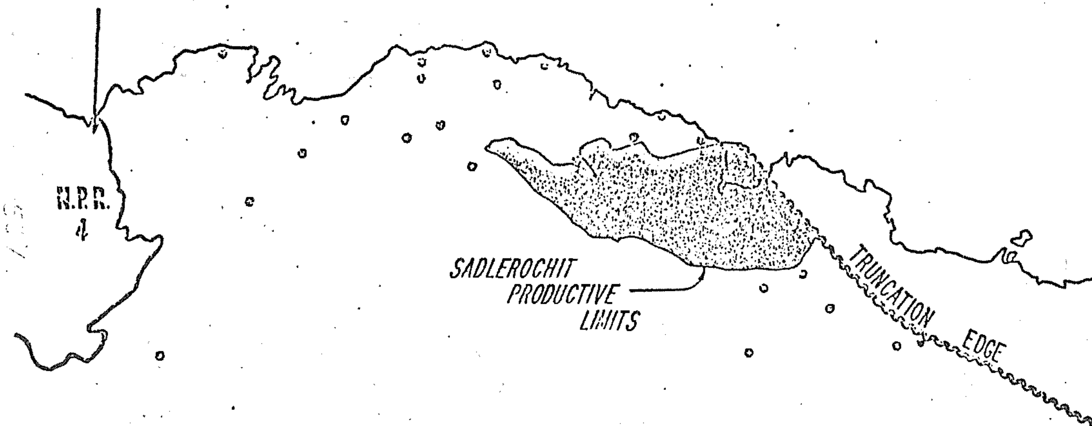
I. SHALE STATISTICS

LITHOLOGY	AVG. ZONE THICKNESS (FT.)	AVG. SHALE INTERVALS / WELL
ZONE 4	160	10.5
ZONE 3	70	1.2
ZONE 2	250	8.8
ZONE 1	70	7.9

II. SMALL SHALE MODEL



PRUDHOE BAY FIELD
AQUIFER DESCRIPTION
SADLEROCHIT RESERVOIR

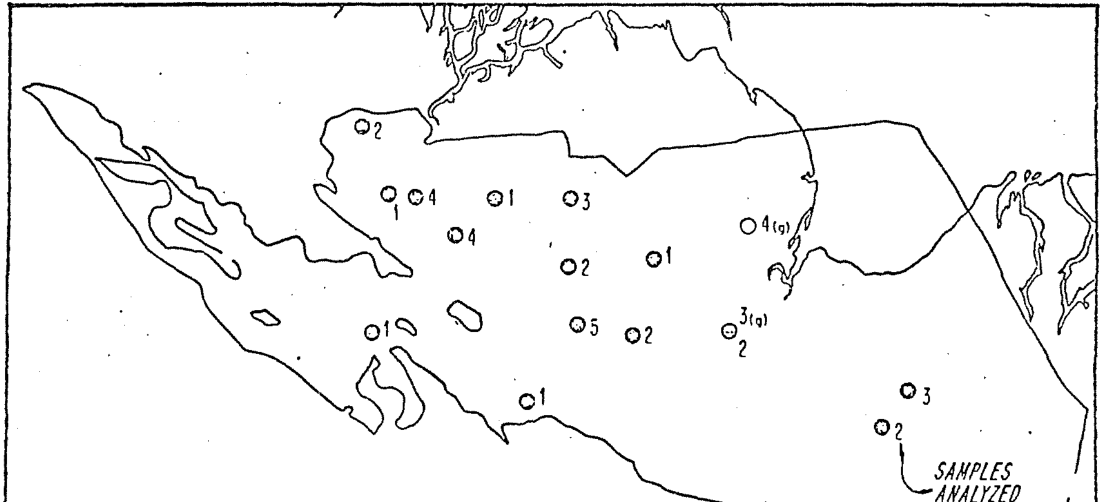


DIST. FROM OWC (mi)	AVG. PROPERTIES φ (%)	K (md)	AQUIFER VOL. (Billion RB)
1.	20.6	225	36
5	18.1	80	163
10	15.3	25	308
15	13.5	12	400
25	11.4	5	705
50	9.1	2	1150

0 5 10 15
Scale in Miles

3945

PRUDHOE BAY FIELD
RESERVOIR FLUID SAMPLES & ANALYSES
SADLEROCHIT RESERVOIR

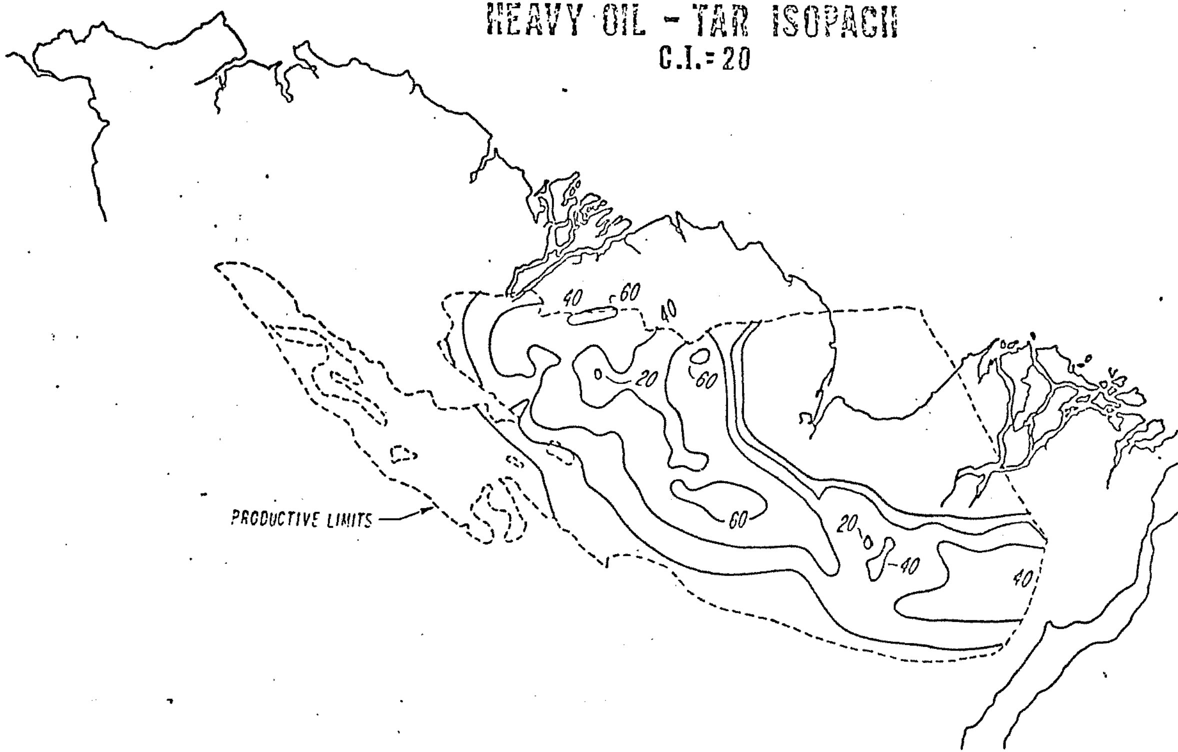


INITIAL FLUID PROPERTIES

	LIGHT OIL	GAS CAP GAS
VOL. FACTOR	1.3-1.4 RB/STB	0.68 RB/MCF
VISCOSITY	0 5-1.2 CP	027 CP
SOL'N GAS	700-900 SCF/STB	
CONDENSATE		35.3 B/$\overline{M}$CF

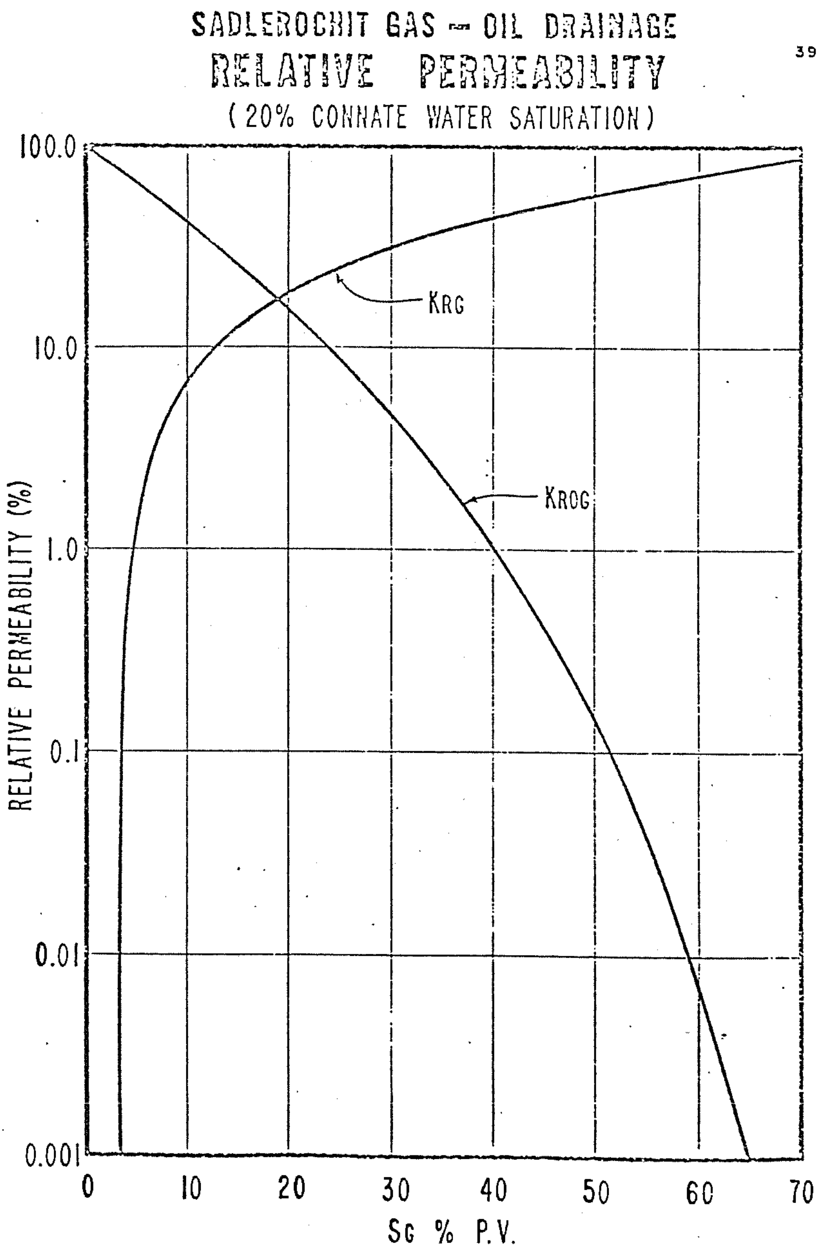
VG 7

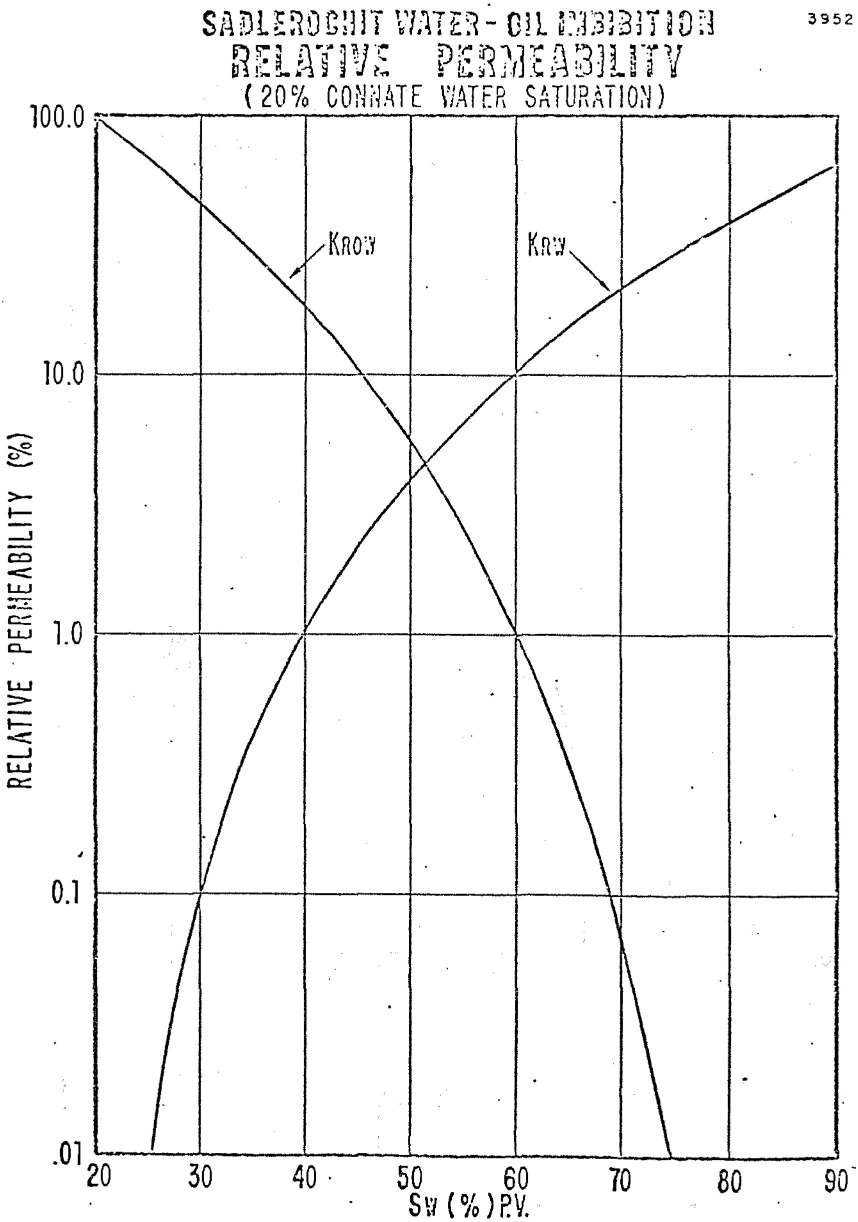
HEAVY OIL - TAR ISOPACH
C.I.= 20



VG 8

3953

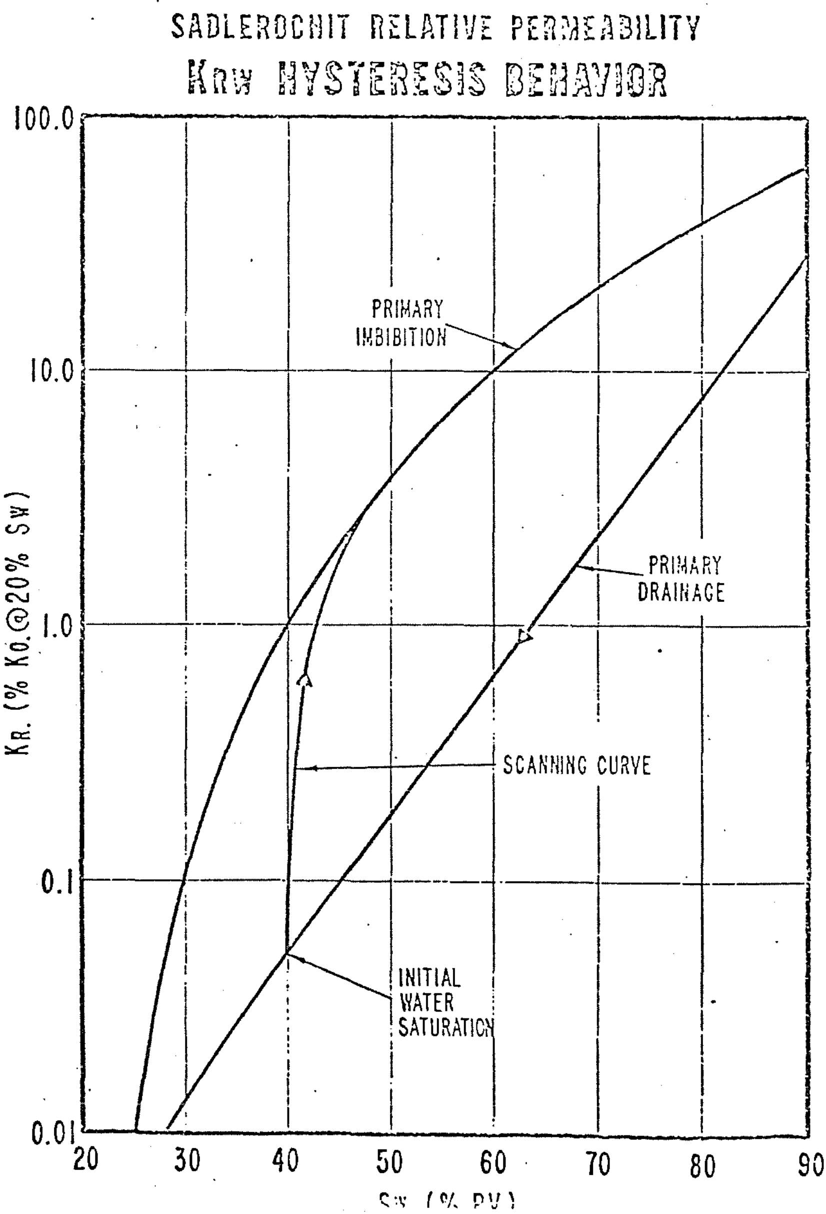

SADLEROCHIT GAS - OIL DRAINAGE
RELATIVE PERMEABILITY
(20% CONNATE WATER SATURATION)
100.0
10.0
1.0
0.1
0.01
0.001
RELATIVE PERMEABILITY (%)
KRG
KROG
0
10
20
30
40
50
60
70
SG % P.V.



3952
SADLEROCHIT WATER - OIL IMBIBITION
RELATIVE PERMEABILITY
(20% CONNATE WATER SATURATION)
100.0
10.0
1.0
0.1
.01
RELATIVE PERMEABILITY (%)
Krow
Krw
20
30
40
50
60
70
80
90
Sw (%) P.V.

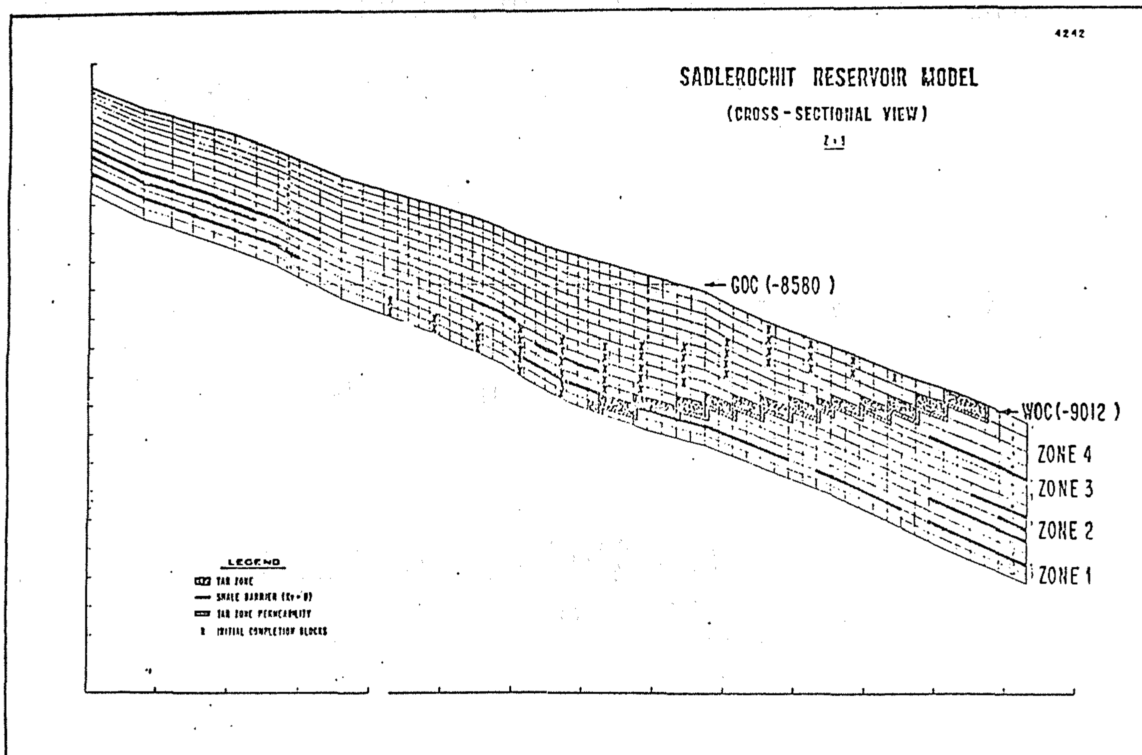
VG 10

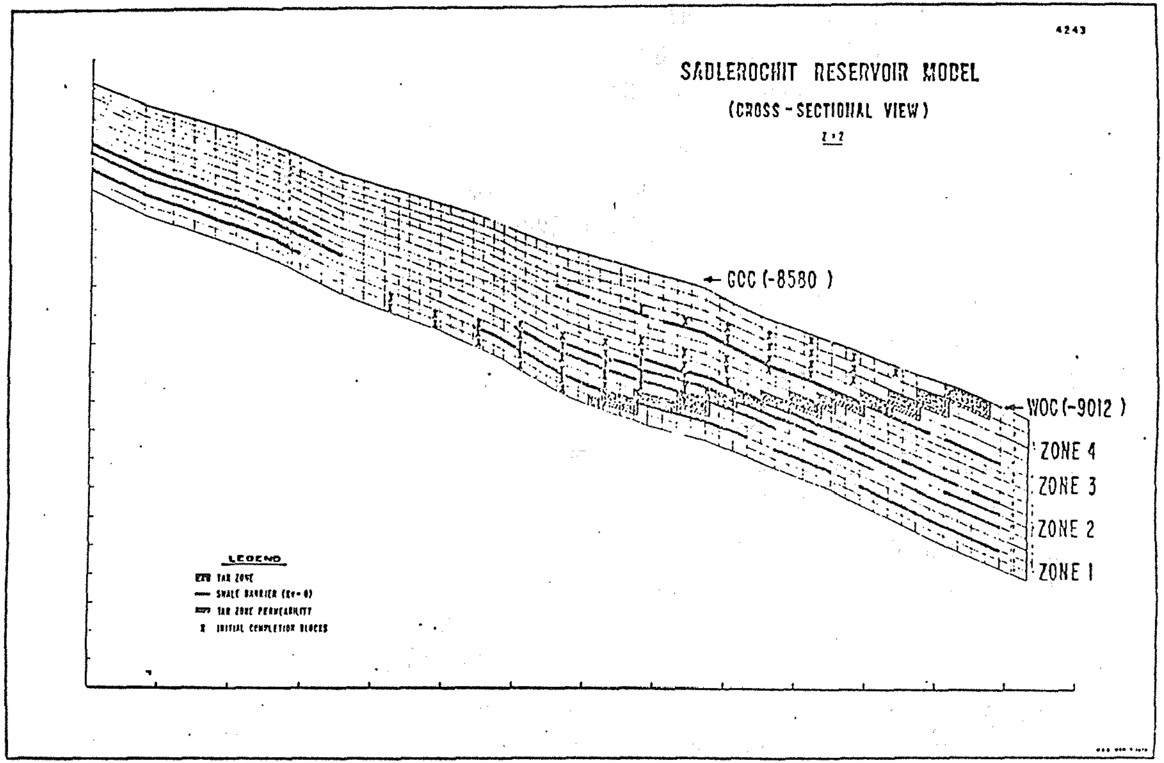
4238


SADLEROCHIT RELATIVE PERMEABILITY
Krw HYSTERESIS BEHAVIOR
100.0
10.0
1.0
0.1
0.01
Kr. (% Ko.@20% Sw)
20
30
40
50
60
70
80
90
PRIMARY IMBIBITION
PRIMARY DRAINAGE
SCANNING CURVE
INITIAL WATER SATURATION

TYPES OF MODELS UTILIZED EXXON RESERVOIR STUDIES

- TWO DIMENSIONAL AQUIFER MODELS
- FINELY GRIDDED TWO AND THREE DIMENSIONAL MODELS
- RADIAL WELL MODELS
- FIELDWIDE THREE DIMENSIONAL, THREE PHASE MODELS
- FIELDWIDE TWO DIMENSIONAL-THREE PHASE, CROSS-SECTION MODELS


4242
SADLEROCHIT RESERVOIR MODEL
(CROSS-SECTIONAL VIEW)
GOC (-8580)
WOC (-9012)
ZONE 4
ZONE 3
ZONE 2
ZONE 1
LEGEND
TAR ZONE
SHALE BARRIER
TAR ZONE PERMEABILITY
INITIAL COMPLETION BLOCKS


4243
SADLEROCHIT RESERVOIR MODEL
(CROSS-SECTIONAL VIEW)
GOC (-8580)
WOC (-9012)
ZONE 4
ZONE 3
ZONE 2
ZONE 1
LEGEND
TAR ZONE
SHALE BARRIER (Kv=0)
TAR ZONE PERMEABILITY
INITIAL COMPLETION BLOCKS

OPERATING LIMITS
CROSS SECTIONAL MODEL
MAIN AREA SADLEROCHIT RESERVOIR

FIELD LIMITS

GAS PRODUCTION:

PRIOR TO GAS SALES = INJECTION CAPACITY (2.0 BCF/D)
+ CONDENSATE SHRINKAGE (2%)
+ FUEL USAGE (8 - 10%)

AFTER GAS SALES = GAS PIPELINE DELIVERY RATE
+ CO_2 REMOVAL (11-12%)
+ CONDENSATE AND GAS CONDITIONING SHRINKAGE (5%)
+ FUEL USAGE (8 - 10%)

WATER PRODUCTION:

NATURAL DEPLETION CASES = 600 MBPD
WATERFLOOD CASES = 1000 MBPD

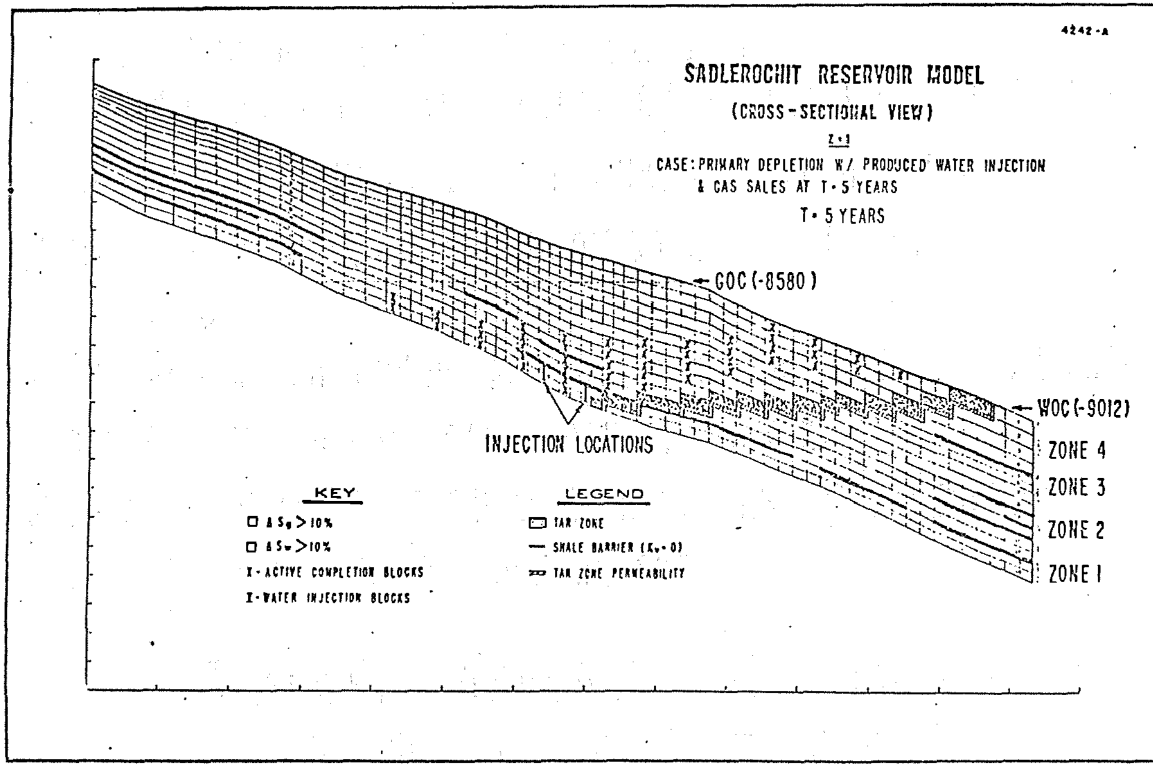
WELL WORKOVERS

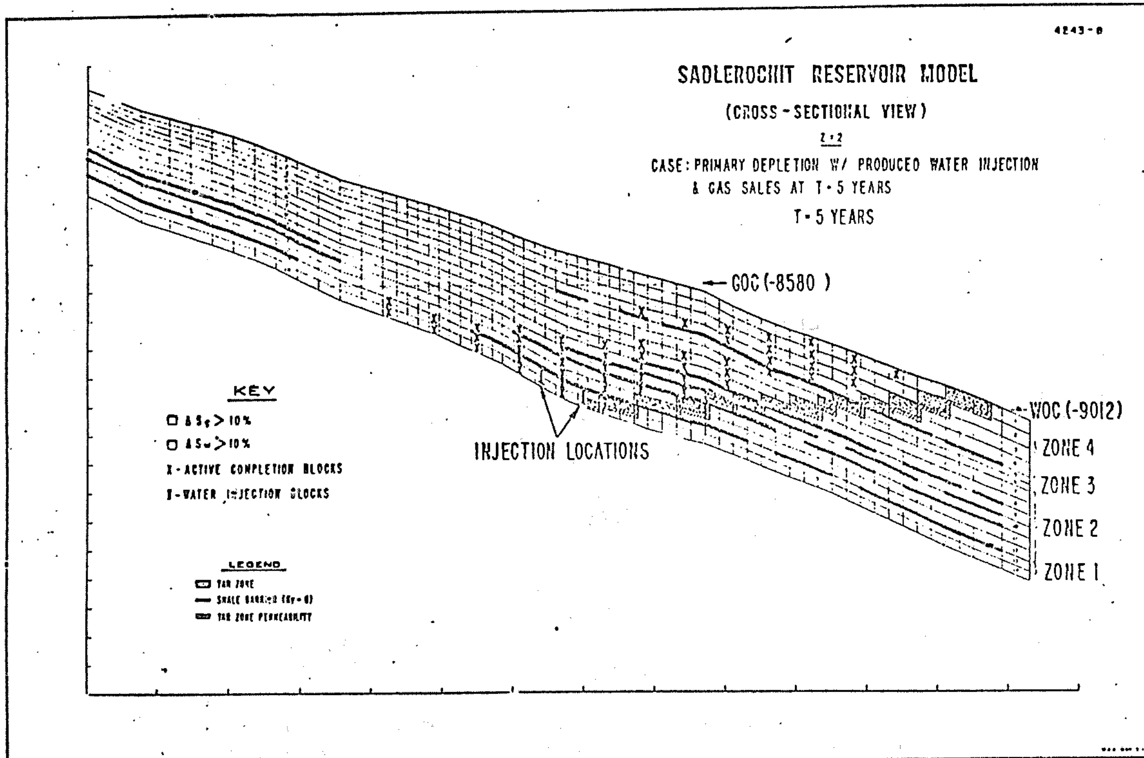
TO REDUCE GAS OR WATER BELOW FIELD LIMITS
TO ATTAIN SPECIFIED OIL RATE INCREASE
SIX MONTH MINIMUM TIME INTERVAL BETWEEN WORKOVERS

PRUDHOE BAY OPERATING PLAN
GENERAL RESERVOIR PERFORMANCE

1. NATURAL WATER INFLUX WILL BE LOW
2. GRAVITY DRAINAGE DOMINANT NATURAL DEPLETION MECHANISM
3. GAS CAP EXPANDS TO COVER MUCH OF OIL ZONE
4. GAS AND WATER CONING WILL OCCUR IN ABSENCE OF PROTECTIVE SHALES
5. OIL DECLINE POINT RELATED TO OIL ZONE WITHDRAWALS
6. 1.5 MMB/D OIL RATE CAN BE SUSTAINED FOR ABOUT 8 YEARS
7. ULTIMATE OIL RECOVERY APPROXIMATELY 40% OOIP AND ULTIMATE GAS RECOVERY ABOUT 75 TO 80% OGIP

98-069 O - 78 - 50


4242-A
SADLEROCHIT RESERVOIR MODEL
(CROSS-SECTIONAL VIEW)
CASE: PRIMARY DEPLETION W/ PRODUCED WATER INJECTION & GAS SALES AT T=5 YEARS
T=5 YEARS
GOC (-8580)
WOC (-9012)
INJECTION LOCATIONS
ZONE 4
ZONE 3
ZONE 2
ZONE 1
KEY
$\Delta S_g > 10\%$
$\Delta S_w > 10\%$
X - ACTIVE COMPLETION BLOCKS
X - WATER INJECTION BLOCKS
LEGEND
TAR ZONE
SHALE BARRIER (K_v = 0)
TAR ZONE PERMEABILITY


4243-B
SADLEROCHIT RESERVOIR MODEL
(CROSS-SECTIONAL VIEW)
CASE: PRIMARY DEPLETION W/ PRODUCED WATER INJECTION
& GAS SALES AT T = 5 YEARS
T = 5 YEARS
GOC (-8580)
WOC (-9012)
ZONE 4
ZONE 3
ZONE 2
ZONE 1
INJECTION LOCATIONS
KEY
Δ Sg > 10%
Δ Sw > 10%
X - ACTIVE COMPLETION BLOCKS
I - WATER INJECTION BLOCKS
LEGEND
TAR ZONE

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

WELL SPACING

1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
LOW PRESSURE AND ARTIFICIAL LIFT

CASE	OIL RECOVERY % OOIP
320 ACRE SPACING	32.2
160 ACRE SPACING	36.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

GATHERING SYSTEM PRESSURE AND ARTIFICIAL LIFT

1.5 MMBOPD
GAS P/L DELIVERIES – 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING

CASE	OIL RECOVERY % OOIP
800 PSI - FLOWING	26.3
300 PSI - FLOWING	31.6
360 PSI - ARTIFICIAL LIFT	36.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

PRODUCED WATER INJECTION

1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

CASE	MAXIMUM WATER INJECTION		OIL RECOVERY
	MMBPD	MMMB	% OOIP
NATURAL DEPLETION-NO WATER INJECTION	–	–	34.2
PRODUCED WATER INJECTION INTO SADLEROCHIT	0.6	5.0	36.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

SOURCE WATER INJECTION TIMING

1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

MAXIMUM WATER INJECTION YEAR	MMBPD	OIL RECOVERY % OOIP
5	1.7	38.7
7	2.0	39.3
9	2.5	39.5
7 5	3.0	40.1
7	3.5	40.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

OIL OFFTAKE RATE

GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

CASE	OIL RECOVERY % OOIP
1.2 MMBOPD	35.9
1.5 MMBOPD	36.2
1.8 MMBOPD	36.3

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

GAS OFFTAKE

1.5 MMBOPD
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

GAS PIPELINE DELIV.		MAX. WATER INJECTION		OIL RECOVERY
YEAR	BCF/D	YEAR	MMBPD	% OOIP
15	2.0	PROD.	0.6	37.5
5	2.0	PROD.	0.6	36.2
10	2.0	7	2.0	40.0
5	2.0	7-9	2.0 - 3.5	39.3-40.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR
RESERVOIR DESCRIPTION

CASE	WATERFLOOD RECOVERY %OOIP	NATURAL DEPL.* RECOVERY %OOIP	INCREMENTAL RECOVERY %OOIP
CURRENT ESTIMATE	40	36	4
LOW VERTICAL PERM	39	32	7
HIGH VERTICAL PERM/LIMITED CONTINUOUS SHALES	38	36	2
EXTENSIVE CONTINUOUS SHALES	43	37	6

* *PRODUCED WATER RETURNED TO RESERVOIR*

TRANSCRIPT OF QUESTIONS
AT OIL & GAS CONSERVATION
COMMITTEE HEARING

Consistent with this plan, it is estimated that source water injection will be initiated within seven years after the start of oil production. Studies indicate that such planning should permit the maximum additional recovery benefits.

Overall, the reservoir management studies indicate that oil recovery of about forty percent can be achieved from the main area Sadlerochit Reservoir. Including reserves from the Eileen area, other Permo-Triassic formations and gas liquids, total liquids recovery is expected to be approximately 9.8 billion stock tank barrels.

Gas recovery is expected to be approximately seventy-five percent of the total gas-in-place, resulting in dry gas reserves of about 26 trillion standard cubic feet after removal of gas liquids and non-hydrocarbons.

Mr. Chairman, this completes our testimony on the reservoir management studies. The next phase of our presentation is to look in more depth at the water injection program plans and some of the work that is required in that area.

MR. HAMILTON: Thank you, Mr. Longwell. I suggest we take about a ten minute break and then we'll have some questions for your witnesses.

MR. REEDER: Fine.

(OFF THE RECORD)

(ON THE RECORD)

MR. HAMILTON: Let's go back

on Record and reconvene the hearing. We have a few questions to ask regarding your reservoir studies, some of them are of kind of a general nature and I may just ask the whole group and you can answer, whoever would like to answer.

Just to clarify one point, when you specify a water injection rate, say, two and a half million barrels per day, does this always include your produced water? Is that the maximum rate, at that time, going into the reservoir and all your --

MR. LONGWELL: Yes -- Yes, Mr. Hamilton, that's correct.

MR. HAMILTON: And is that rate always held constant during the time that you say that you're injecting at a particular rate?

MR. LONGWELL: It varies from study to study. Normally, that's the rate that's held for the first several years, and then it decreases with time. Some of the other members might give a general statement as to how that rate varied with time in our individual studies.

MR. LAMPRECHT: Yes. My name is Don Lamprecht, with Arco. In our studies, we generally keep the total water injection rate constant for about five to seven years, after which we cut it down. Generally, after twenty years, we're only returning produced water.

MR. MROSOVSKY: In the case of

BP, we kept it constant for fifteen years and then switched to produced water only.

MR. HAMILTON: I think it would be helpful if you could supply the Committee, and I'm asking all of you this, for your cases that you've submitted for the Record here, if you could submit a daily rate of the oil/water/gas with time, and also any gas re-injection rates with time, and the pressure behavior with time, for your simulation runs. Is that possible?

MR. LONGWELL: Yes, Mr. Chairman, that's -- that is possible. We can -- On how many -- Will you want it on the representative cases of --

MR. HAMILTON: Well, on the runs you've included in your presentation.

MR. LONGWELL: On all cases?

MR. HAMILTON: Yes.

MR. LONGWELL: Okay.

MR. HAMILTON: I know each of you had a workover schedule built in to your models. Could one of you talk a little bit on that and just how they're operated and approximately how many workovers you had, per well, on an average?

MR. LAMPRECHT: I can start that. We have a rather efficient workover routine in the model, in that workovers are completed instantaneously. We allow for no down time on a workover. We use sealed gas and water handling limits to specify workovers. In other words, if we specify that we can only inject two billion cubic feet per day, and at one point, we're 2.1, it will -- the model will seek out the highest GOR layer and it will shut that layer in and re-check. If that workover didn't work, it will go in and shut the next highest fuel oil layer in.

I would say the average well in the field, as far as gas and water shutoffs, would probably have five to six workovers over the life of the field.

MR. MROSOVSKY: In the case of BP, I think I covered workover algorithms in some detail in my testimony, but as regards the frequency of those workovers, for water shutoffs we might do, say, seven hundred over the life of the field, which would come to somewhat over -- slightly more than one per well, on the average.

As far as gas shutoffs, we intended to set our limit very high, so that we often did few or no gas shutoffs. I couldn't really give a figure. We took a rather unfavorable view of how successful gas shutoffs would be in practice, although they would be successful in the models.

MR. JUSTICE: Alan Justice, with Exxon. In our case, as I've described in the testimony, we did workovers if a certain rate of oil production increase could be achieved and we limited that to no more frequent than six months between workovers. We have about 500 wells in the model and I suppose, on the average, we worked over each well about twice during the life, so that would amount to a thousand workovers, perhaps.

MR. HAMILTON: Without the benefit of the schedules that I asked for, I was just curious of how much gas re-injection occurred in some of your runs where you delayed gas sales for quite a number of years. Would it be great enough that additional compression equipment would be necessary?

MR. LONGWELL: In -- We can comment individually in just a moment, Mr. Chairman, but in general, the existing compressors that are planned for installation on the slope, the two BCF per day that Mr. Simpson mentioned, were maintained and additional compression was not added during the life of the field, during the primary operations prior to gas sales.

I think, in Exxon's case, if I recall the numbers properly, in the first, I think, five or six years, there was about two trillion cubic feet of gas that was injected. In cases where gas sales were delayed, say as late as twenty years or so, we were in the fifteen to twenty trillion cubic feet of gas that had to be re-injected, but it was all at a maximum rate of two BCF per day.

MR. HAMILTON: You didn't find

that that limitation affected your oil -- potential oil rates you could maintain?

MR. LONGWELL: The oil rate was maintained till about the eighth or ninth year, and then started to decrease and, of course, that's subject to -- you know, to looking at the economics at the time as to just how much gas can you handle and still maintain an oil production rate, and I'm sure that would be a big -- you know, a big area to evaluate at the time.

UNIDENTIFIED VOICE: (INAUDIBLE)

MR. LONGWELL: I think that's a general statement that covers all of the cases, Mr. Chairman.

MR. HAMILTON: Fine, thank you. During the period that -- in forecasts of gas sales where you were taking out, presumably, gas liquids out of the gas, or they will be taken out in the event of gas sales, could you tell me how much of those liquids could be put back into the oil stream and go into the oil line? Do you have any idea of a percent of something of that nature?

MR. JUSTICE: If I understood you correctly, prior to gas sales, is that the time you were speaking to?

MR. HAMILTON: No, after gas sales start and you have processing, dropping out gas liquids, how much of those gas liquids could be put in the oil stream?

MR. JUSTICE: We spoke to ten to fifteen barrels per million cubic feet being extracted and that's for the -- to get the gas in condition for marketing. We anticipate that we could put all those liquids into the oil pipeline.

MR. HAMILTON: All of them, okay.

MR. LAMPRECHT: I'd like to comment, Don Lamprecht with Arco. Certainly, as long as we're on plateau oil rates, I feel so, anyway, that all of the gas liquids could be put back into the oil pipeline. At extremely low pipeline rates, I don't know for sure how much could be put in without affecting vapor pressures, and I'm really not an expert on that field, but certainly while we're on a plateau rate, I believe we could put all the NGL's back in the line.

MR. HAMILTON: Thank you. I know you all spoke of injecting the produced water. At what produced water rate do you think you will start injecting this water?

MR. LONGWELL: Mr. Chairman, our current thinking now is that we're looking at rates at about 100,000 barrels per day of produced water from the total field, at which time we would start re-injecting it into the Sadlerochit. But, of course, that will vary, it -- depending on where the water is located, where it is being produced in the field, but in this two to four year range, at which time, we would plan on putting produced water back on the -- into the reservoir, that was at about 100,000 barrels a day level. But it certainly could vary from that, depending on the location.

MR. HAMILTON: I think if you can supply the information that we've requested, I believe that's all the questions we have at this time.

MR. REEDER: All right. We will supply that, Mr. Chairman, before the Record is closed.

MR. HAMILTON: Very good.

MR. REEDER: I believe, now, we can proceed to our testimony on the water flooding implementation plan.

(PAUSE)

HAROLD HEINZE

Mr. Chairman, members of the Alaska Oil & Gas Conservation Committee, ladies and gentlemen, my name is Harold Heinze. I received a Bachelor of Science Degree in Petroleum Engineering from the Colorado School of Mines in 1964. Since 1965, I have been employed by Atlantic Richfield as a Petroleum Engineer. Since January, 1969, I have been involved in various aspects of reservoir and production engineering of the Prudhoe Bay Field. My current position is Engineering Manager for our North Alaska District.

In all of the model studies just discussed, we have

And these -- I'll read these in the order that we received them. Question one, and this is directed to Atlantic Richfield, BP, Exxon and Dr. vanPoollen, "What do you consider to be the limits of accuracy of your models in percent recovery?"

Would anyone like to respond to that?

Would you please identify yourself?

MR. MROSOVSKY: Ivan Mrosovsky with BP. We would agree with the statement made by Mr. van Poollen as far as comparison between different cases. We would say that if the difference is less than about half a percent, it would hardly be meaningful, for reasons stated in our testimony. As to the absolute value of a recovery factor, again, it would be difficult to put an absolute limit on it, because it's a matter of probability. We've chosen what we think is -- calculated what we think are the most likely values, but one could certainly be several percent off.

MR. JUSTICE: Allen Justice, with Exxon. I'd respond to the same question following the lines that Dr. van Poollen and Mr. Mrosovsky have answered it. When you're looking at one reservoir description using one model, I think that we could say that answers within one-half of one percent could be meaningful. If you're looking at different interpretations of the reservoir, using different models, I think we presented the results in the testimony that varied for a given case between three and four percent. And that may represent a reasonable accuracy of model predictions.

MR. LAMPRECHT: Don Lamprecht, with ARCO. There's actually two parts to this question. The first part would be, I would think, is what's your confidence on the absolute answer. And we would say that the absolute answers that we're obtaining are probably correct within 10 or 15% of the predicted value. The comparison between cases, though, are more precise, especially when you have rates retained. And we would say that answers within a half a percent between cases could show you some directional values. So with one description, they're more precise. But on the absolute answer, I'd say they're only correct within 10 to 15% of the predicted value.

CHAIRMAN: Thank you. Dr. van Poollen, do you . . .

DR. VAN POOLLEN: Van Poollen, Merel for the record. I believe I answered the question during my testimony, and I can say that I myself don't even feel that 10 to 15 percent is a good outer boundary. However, in most instances we look at what would a field like this give you as an approximate recovery factor based on experiences elsewhere in the world. And I think all of our numbers, which were independently derived, are showing numbers that show similarity what a field of this nature could do somewhere else in the world.

CHAIRMAN: Thank you. The second question we have is directed to BP, Atlantic Richfield and

Exxon. And I believe this may have been answered in the previous question sessions that we had yesterday, but I'll state the question here, and see if you have a response. Let's see, "Are you going to put the C-3 and C-4 in the oil line?", and "Are you sure?"

MR. JUSTICE: Allen Justice, with Exxon Oil. Try that first, and I think some of the others may want to respond to this. Without knowing what the gas pipeline specifications are going to be, and what the TAPS specifications might be at the start of gas sales, it's very difficult to say specifically what the compositions of the NGL's might be. But in the work that we've done, we've assumed that practically all of the propanes, such as C-3's, could be put into the gas pipeline, and then the isobutanes, and about half the normal butanes would be used as fuel in the processing plant or the conditioning plant. Then, the 10 to 15 million barrels -- 10 to 15 barrels per million that we talked to the in the testimony was based on about half the normal butanes and the pentanes plus fractions. But at any rate, whether the -- those components are shipped through the gas pipeline, whether they're put into the oil pipeline or whether they're used as fuel in the processing, they will be put to beneficial use.

CHAIRMAN: Thank you.

MR. MROSOVSKY: Ivan Mrosovsky, BP Alaska. We have done some calculations that show that under certain circumstances, certain condition of the pipeline, one could probably get all the butanes into the line and even a little propane. However, are we sure of doing this, no, certainly not. It depends greatly both on the condition -- the circumstances in the oil line, and the specification for the gas quality, which is unknown at the moment. Would expect that perhaps most of the butanes and pentanes would go down one line or another, but if not, they would probably be used as fuel in the gas conditioning plant.

MR. LAMPRECHT: I spoke to this -- Lamprecht, with ARCO. I spoke to this question yesterday, and it's actually related to the actual specifications on the pipeline Of course, these NGL's could affect vapor pressures. And since we do not know exactly what the mixing is going to do, other than while we're -- have a full pipeline, I would think we could put all of them in the pipeline. But it depends on the pipeline specs which are just not known precisely at this time.

CHAIRMAN: You're speaking of the gas line specs?

MR. LAMPRECHT: Gas and oil pipeline.

CHAIRMAN: The third question, still directed to BP, ARCO and Exxon. "Were there any runs made with waterflood beginning on the first day of production?"

MR. JUSTICE: As we addressed in the testimony, there will be time required to make responsible decisions regarding waterflooding, so we don't think it's a reasonable assumption to assume that you can begin water injection at the same time you'd start up oil production, but purely for sensitivity checks, we have looked at that situation. In the case I'm referring to, we began water injection at the start-up of oil production, fully maintaining reservoir pressure. In that case there were no gas sales whatsoever. This case indicated recoveries less than 1% higher than if we have gas sales beginning after five years, and water injection beginning after 7 years. So we see very little difference, actually, between the cases.

MR. LAMPRECHT: Don Lamprecht with ARCO. We had done some work back as early as 1970 on some one-dimensional models which I mentioned in my testimony which showed that the early water injection could actually fere -- interfere with the natural gravity drainage mechanism. In our most recent studies, we have not considered water injection this early since we don't really consider it to be practical.

MR. MROSOVSKY: Ivan Mrosovsky, BP Alaska. We also didn't do a run, actually, from time zero with water injection because we didn't feel it was practical. We did sometime back do a run where we shifted the water injection of three and a half million barrels a day two years early, that would be two and a half years, which we also don't consider a practical case. With, nevertheless, gas sales at four and a half years, and by this moving forward by two years of this very large volume of water, we only gained half a percent in the final recovery, which, as we've already mentioned, we barely consider significant.

CHAIRMAN: Thank you. The fourth question I have here, again directed to BP, Atlantic Richfield and Exxon, "Were any runs made where the pressure was kept above 3800 psi?"

MR. JUSTICE: I think I just addressed that question with the prior answer.

CHAIRMAN: Yes, I believe you did.

MR. LAMPRECHT: Don Lamprecht, w[illegible] ARCO. In one particular case we talked about yesterday, where we started selling gas at 15 years, it was a natural depletion case, with just return of produced water, the reservoir pressure at 15 years was -- had plateaued at about 3400 pounds. We really haven't run any cases where the pressure has been -- plateaued about 3800 pounds.

MR. MROSOVSKY: Ivan Mrosovsky, BP Alaska. Four of the cases that we presented yesterday did, in fact, maintain pressure above that 3800 pounds. Those cases were numbered 3, 4 and 5 and case number 10. And in those four cases, which are all high-water injection case, the pressure remained above 3800 pounds out to 20 years.

CHAIRMAN: There's one final

question, and I'll read the question, but I think this has been answered in the course of the hearing, and I won't ask for a -- an answer. "Account for differences between gas volumes of 2.373 and 2.7 for gas sales of 2 billion cubic feet a day". I think there's been testimony showing what the losses occuring between 2.7 produced volumes and the 2 billion a day gas sales volumes are.

At this time, in closing the hearing, I'd just like to make a few remarks. We've heard quite a bit of testimony both from operators and the State on model studies that have been made. And I think it's quite apparent that a great deal of work has been done on this field. But it's also quite apparent that we can't formulate any final plans until we do get some production history. And for that reason, I'm sure there will be subsequent hearings devoted to this field, or this pool, forthcoming after we do get some production history.

And I believe that will conclude this hearing at this time, and I'd like to say that the hearing record will be kept open till 4:00 p.m., May the 16th. Thank you.

END OF PROCEEDINGS

* * * * *

CERTIFICATE

UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

I, Teresa E. Mielke, Notary Public, in and for the State of Alaska, residing at Anchorage, Alaska, and Electronic reporter for R & R Court Reporters, do hereby certify:

That the annexed and foregoing hearing was taken before me on the 6th day of May, 1977, beginning at the hour of 9:00 a.m. at the Ramada Inn, Anchorage, Alaska,

That the witnesses were duly sworn to testify to the truth, the whole truth, and nothing but the truth,

That this transcript, as heretofore annexed, is a true and correct transcription of the hearing taken by me electronically and thereafter transcribed by me.

I am not a relative or employee or attorney or counsel of any of the parties, nor am I financially interested in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 8th day of May, 1977.

Teresa E. Mielke
Notary Public in and for Alaska
My commission expires May 6, 1979

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

WELL SPACING

1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
LOW PRESSURE AND ARTIFICIAL LIFT

Case No.	CASE	OIL RECOVERY % OOIP
1	320 ACRE SPACING	32.2
2	160 ACRE SPACING	36.2

SUPPLEMENTAL INFORMATION
PROVIDED AFTER HEARING
AT REQUEST OF
DIVISION OF OIL & GAS CONSERVATION

807

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

GATHERING SYSTEM PRESSURE AND ARTIFICIAL LIFT

1.5 MMBOPD
GAS P/L DELIVERIES – 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING

Case No.	CASE	OIL RECOVERY % OOIP
3	800 PSI – FLOWING	26.3
4	300 PSI – FLOWING	31.6
2	380 PSI – ARTIFICIAL LIFT	36.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

PRODUCED WATER INJECTION
1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

Case No.	CASE	MAXIMUM WATER INJECTION MMBPD	MAXIMUM WATER INJECTION MMMB	OIL RECOVERY % OOIP
5	NATURAL DEPLETION - NO WATER INJECTION	—	—	34.2
2	PRODUCED WATER INJECTION INTO SADLEROCHIT	0.6	5.0	36.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

SOURCE WATER INJECTION TIMING

1.5 MMBOPD
GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

Case. No.	MAXIMUM WATER INJECTION YEAR	MMBPD	OIL RECOVERY % OOIP
6	5	1.7	38.7
7	7	2.0	39.3
8	9	2.5	39.5
9	5	3.0	40.1
10	7	3.5	40.2

OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

OIL OFFTAKE RATE

GAS P/L DELIVERIES - 2.0 BCF/D AT YEAR 5
PRODUCED WATER INJECTION
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

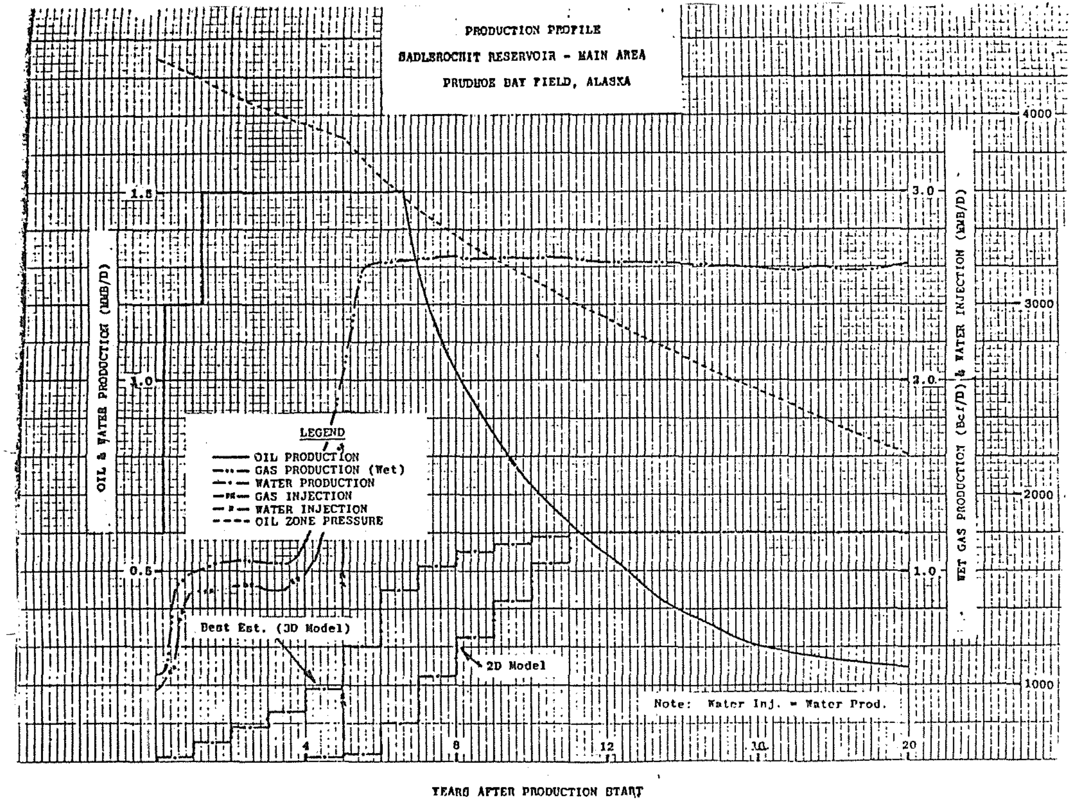
Case No.	CASE	OIL RECOVERY % OOIP
11	1.2 MMBOPD	35.9
2	1.5 MMBOPD	36.2
12	1.8 MMBOPD	36.3

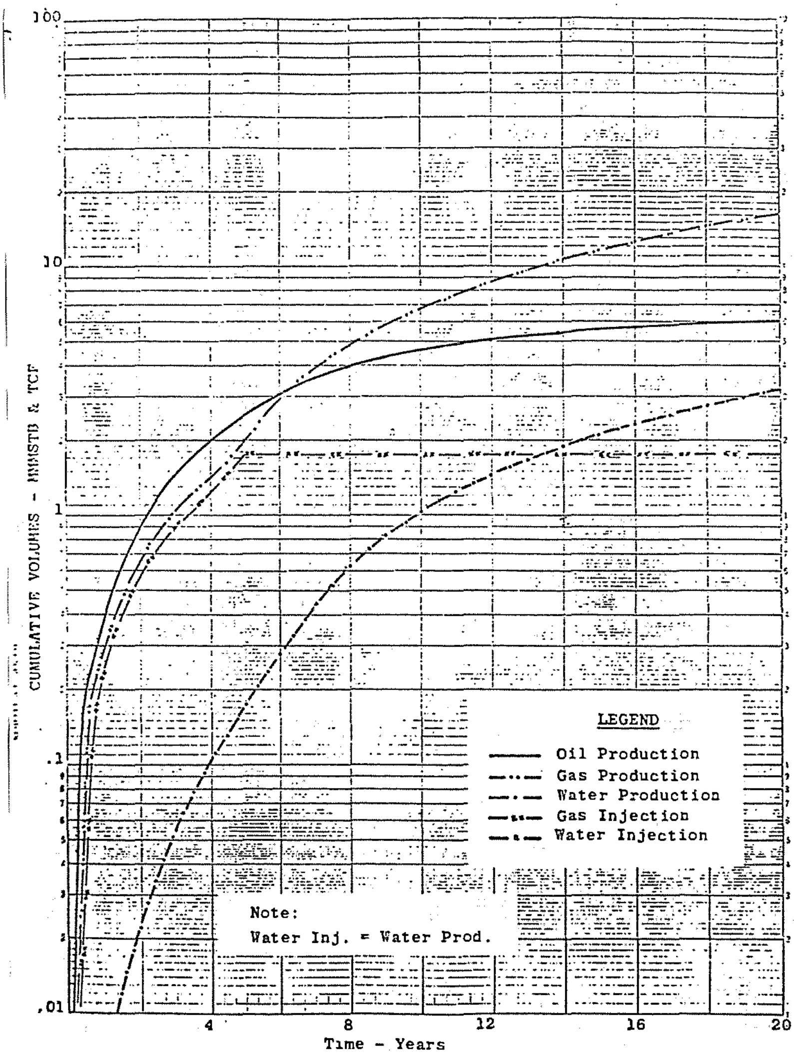
OPERATING PLAN SENSITIVITY STUDIES
MAIN AREA SADLEROCHIT RESERVOIR

GAS OFFTAKE

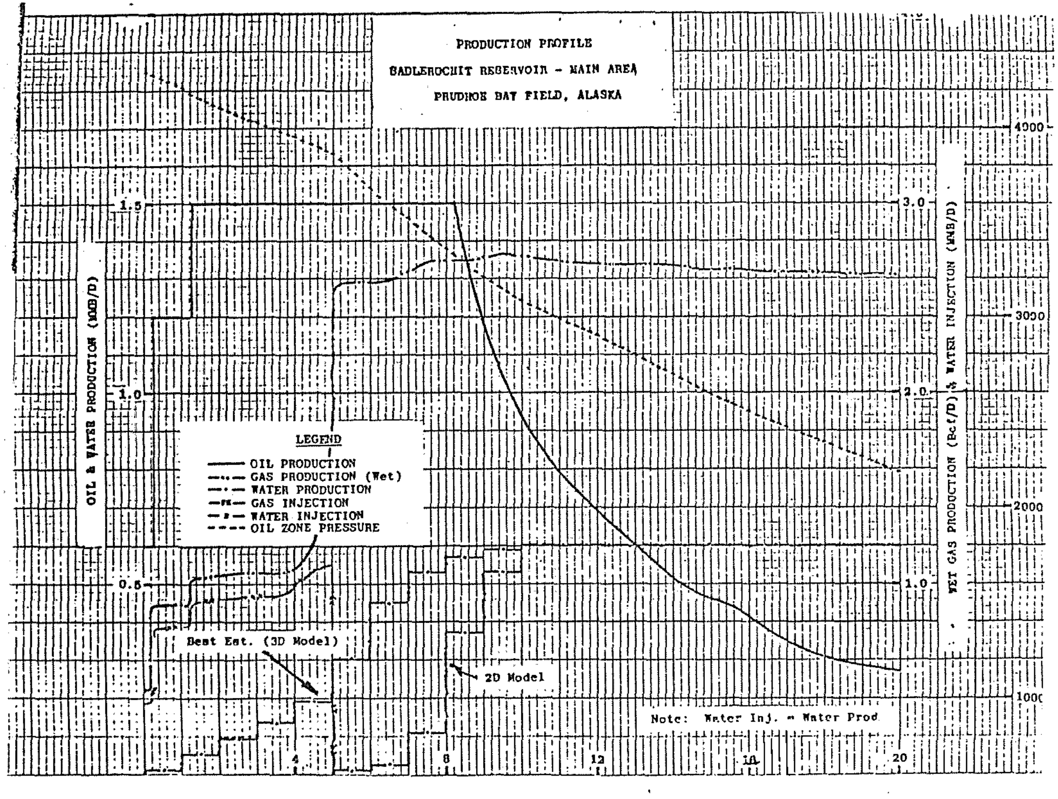
1.5 MMBOPD
160 ACRE WELL SPACING
LOW PRESSURE AND ARTIFICIAL LIFT

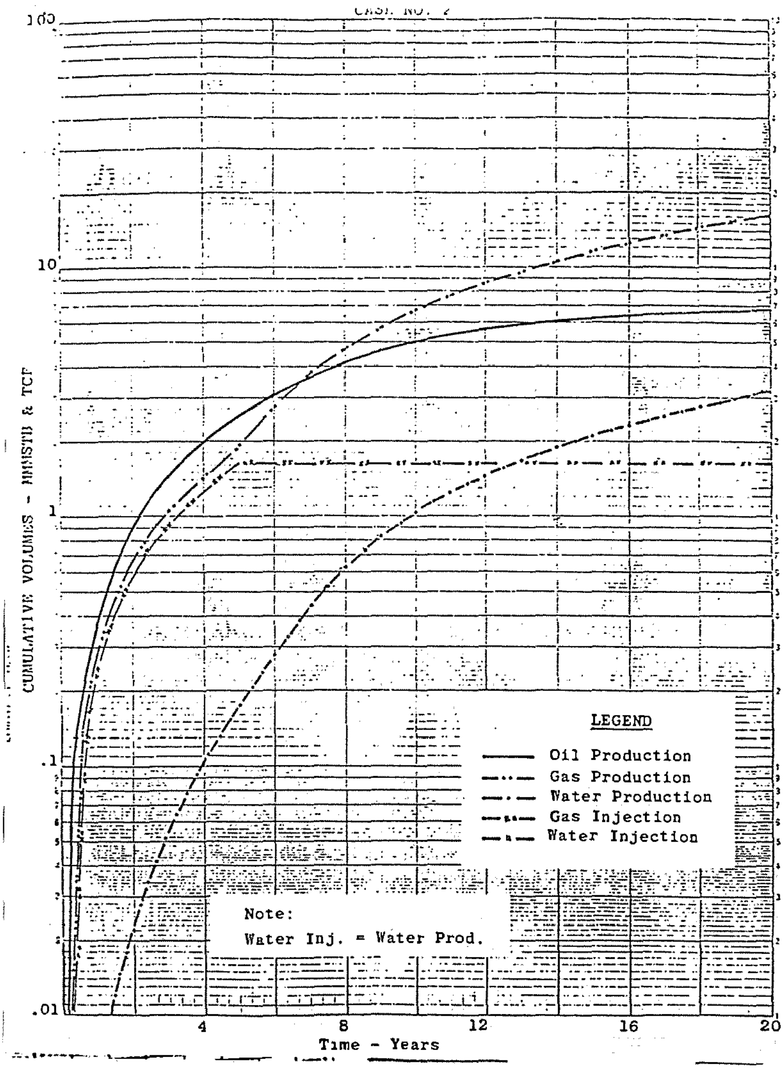
Case No.	GAS PIPELINE DELIV. YEAR	GAS PIPELINE DELIV. BCF/D	MAX. WATER INJECTION YEAR	MAX. WATER INJECTION MMBPD	OIL RECOVERY % OOIP
13	15	2.0	PROD.	0.6	37.5
2	5	2.0	PROD.	0.6	36.2
14	10	2.0	7	2.0	40.0
7,8,10	5	2.0	7-9	2.0 - 3.5	39.3-40.2

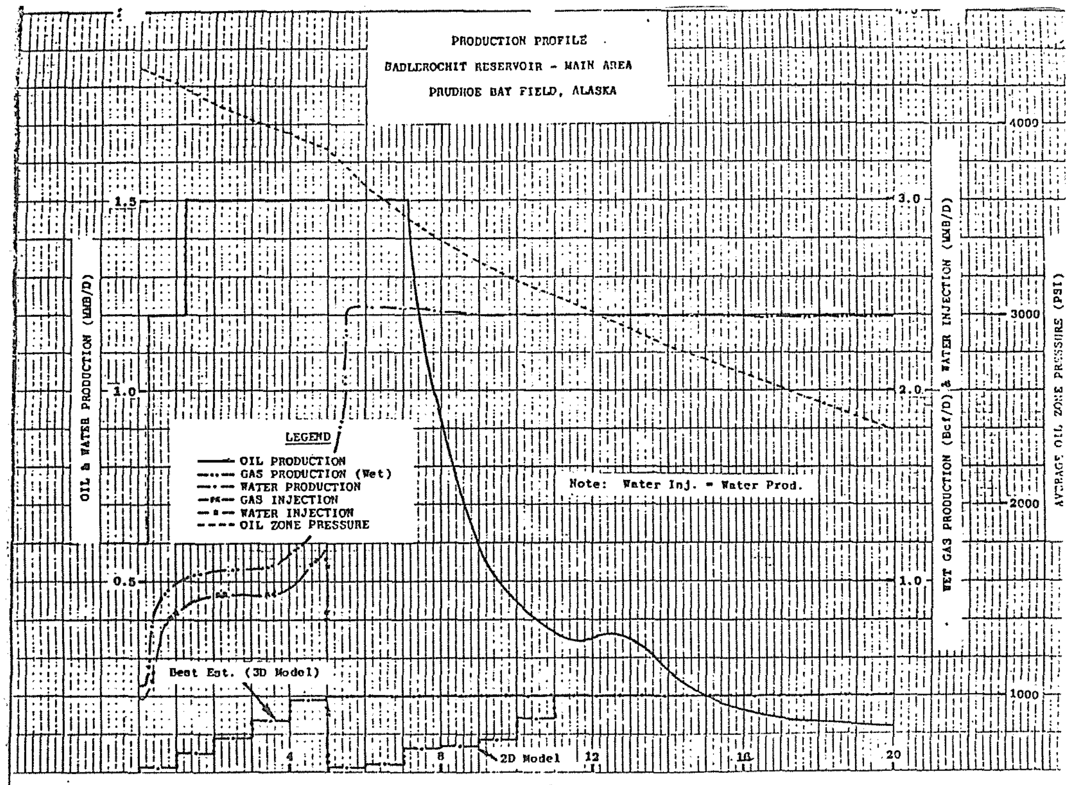

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: Water Inj. = Water Prod.
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20
YEARS AFTER PRODUCTION START

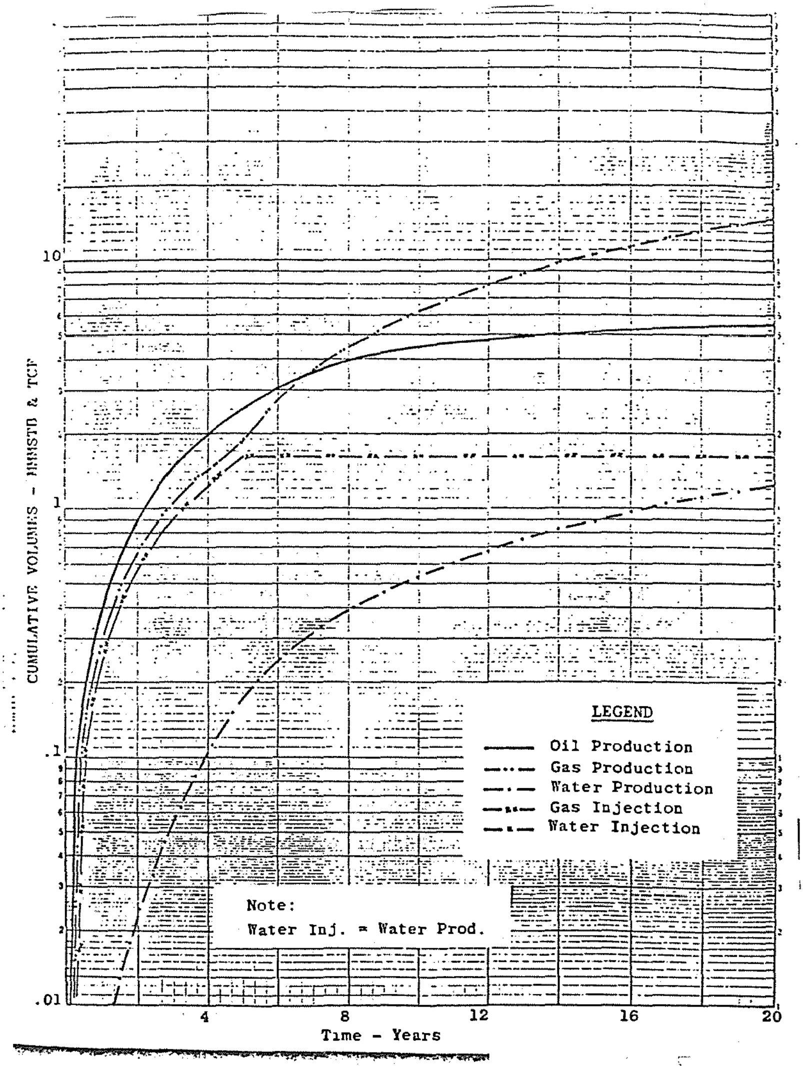


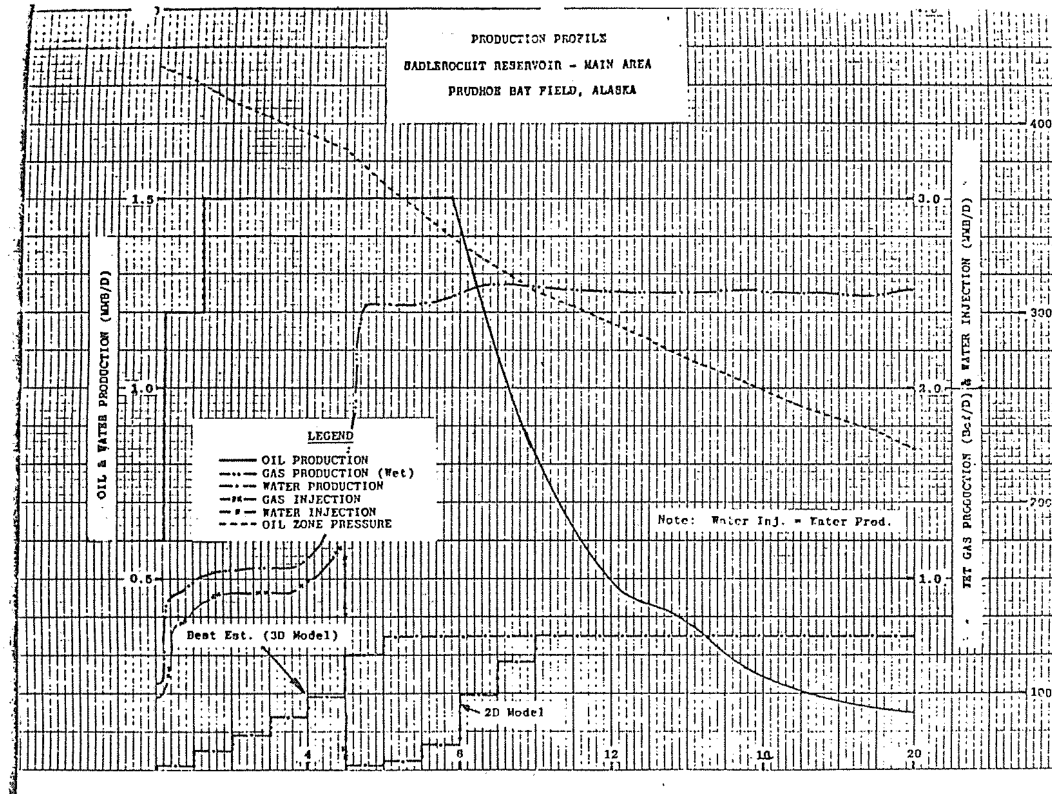
100
10
1
.1
.01
CUMULATIVE VOLUMES - MMMSTB & TCF
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.

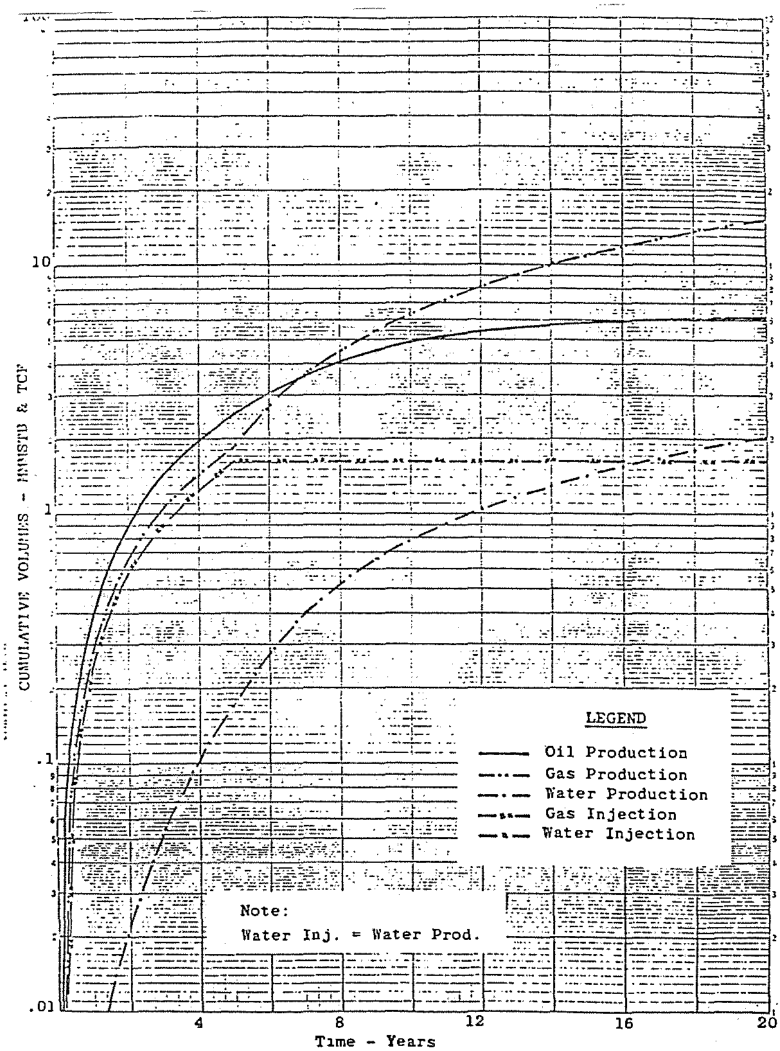

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: Water Inj. = Water Prod
4
8
12
20


CASE NO. 2
CUMULATIVE VOLUMES - MMSTB & TCF
100
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.


PRODUCTION PROFILE
BADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Note: Water Inj. = Water Prod.
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

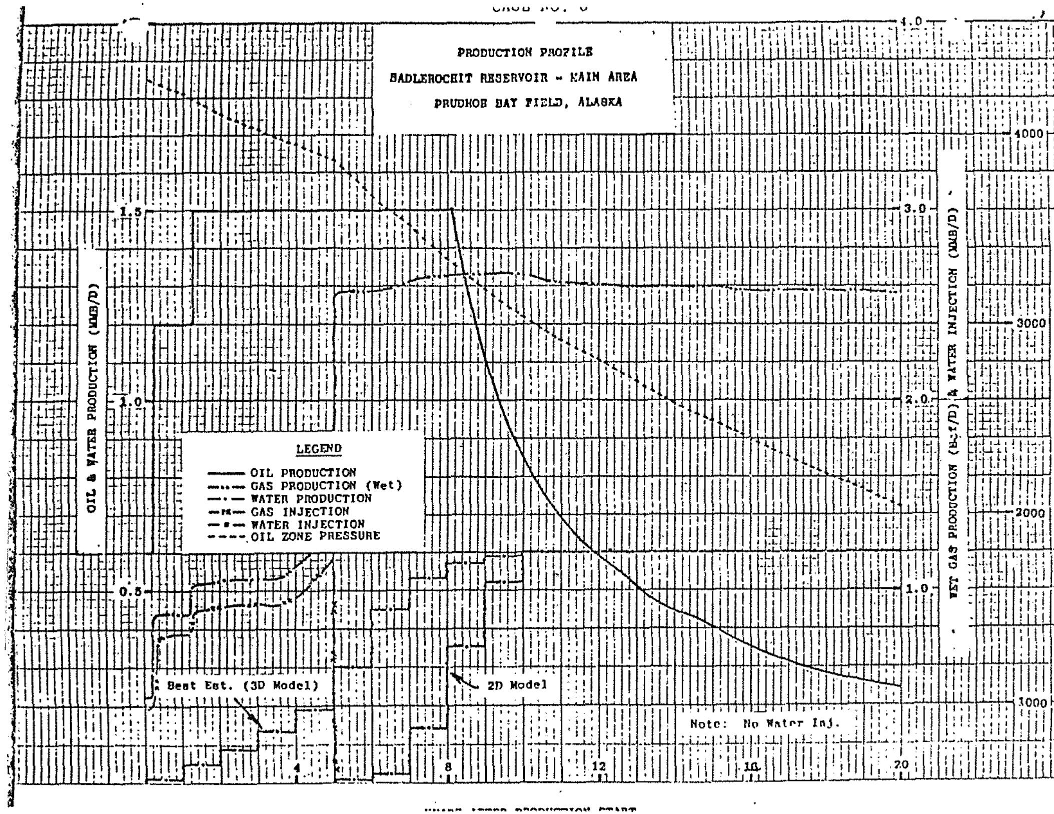

CUMULATIVE VOLUMES - MMSTB & TCF
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.

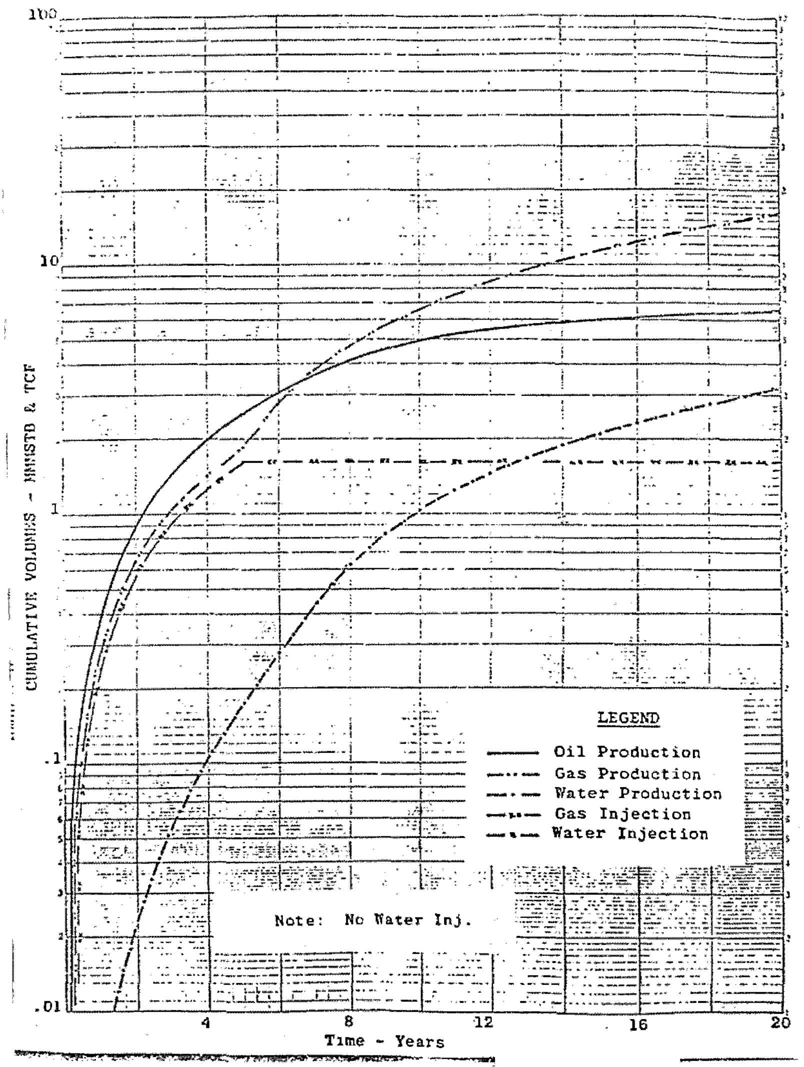

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Note: Water Inj. = Water Prod.
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
20



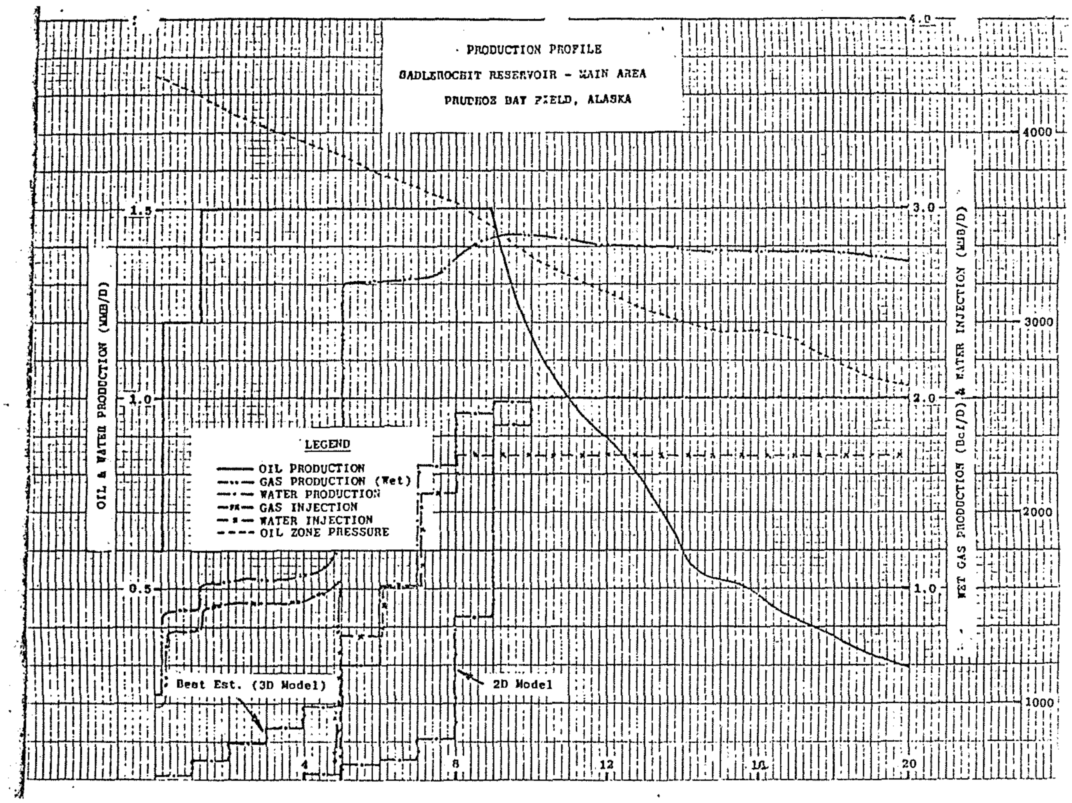
CUMULATIVE VOLUMES - MMMSTB & TCF
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.

98-069 O - 78 - 52

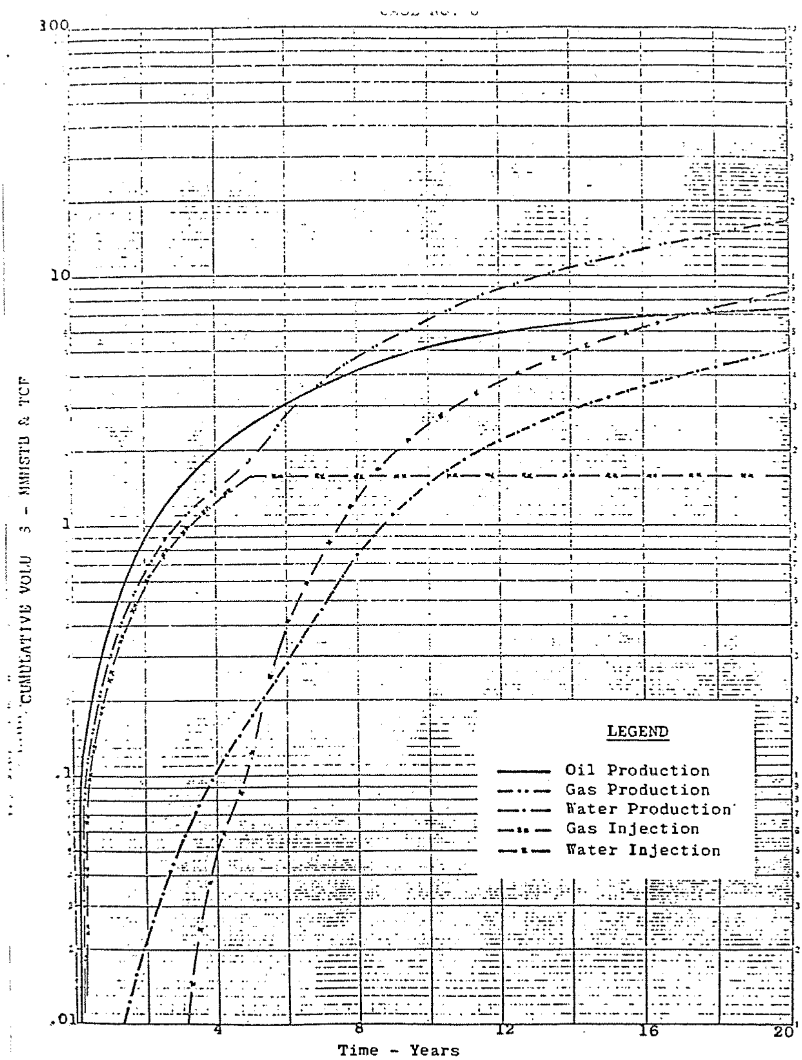

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (MMCF/D) & WATER INJECTION (MMB/D)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: No Water Inj.
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

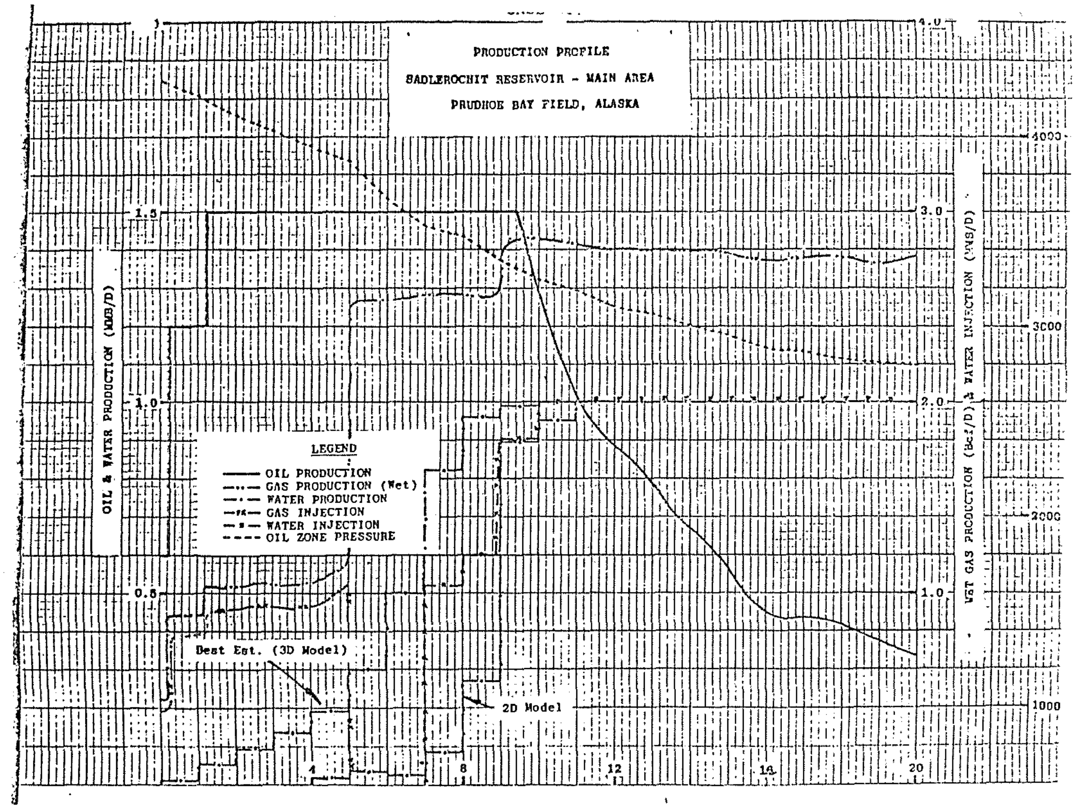


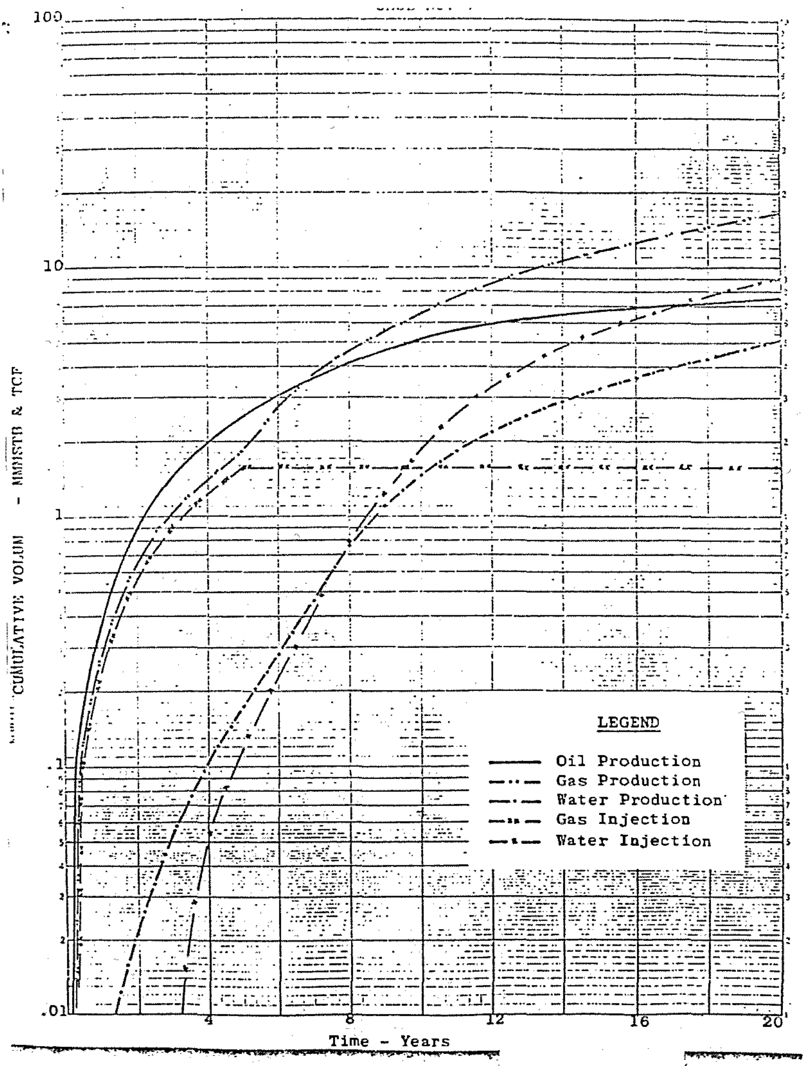
CUMULATIVE VOLUMES - MMSTB & TCF
100
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note: No Water Inj.

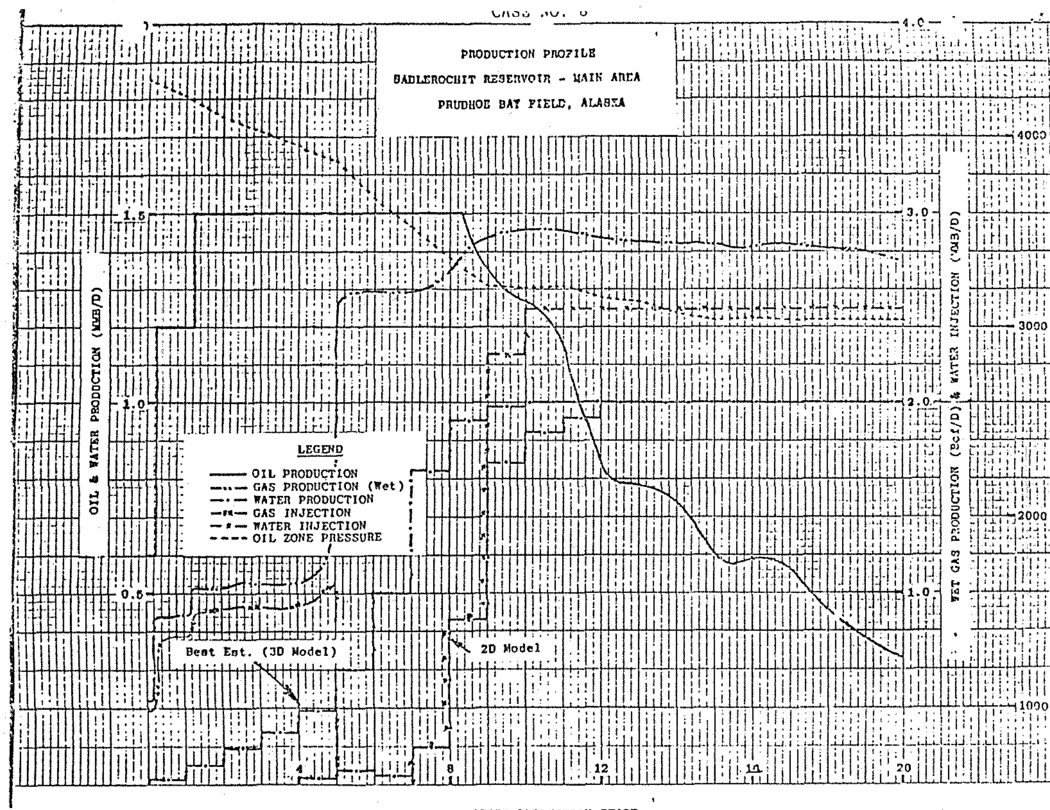


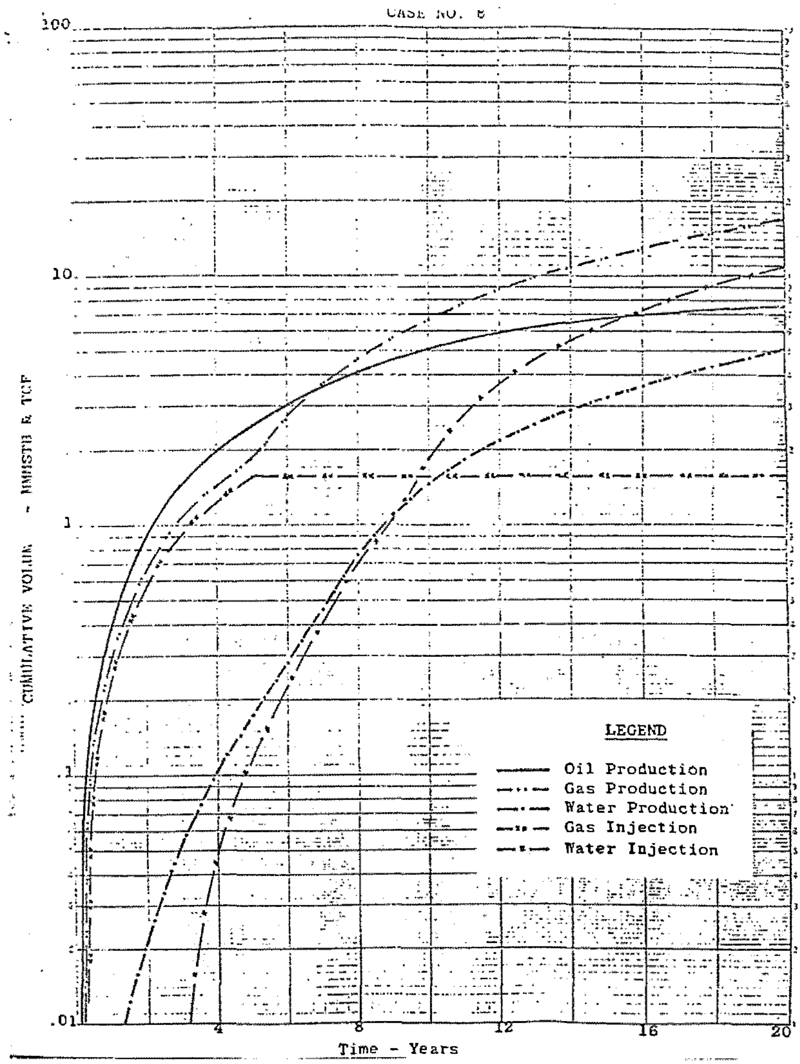
PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20


CASE NO. 6
300
10
1
.1
.01
4
8
12
16
20
Time - Years
CUMULATIVE VOLU 3 - MMSTB & TCF
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

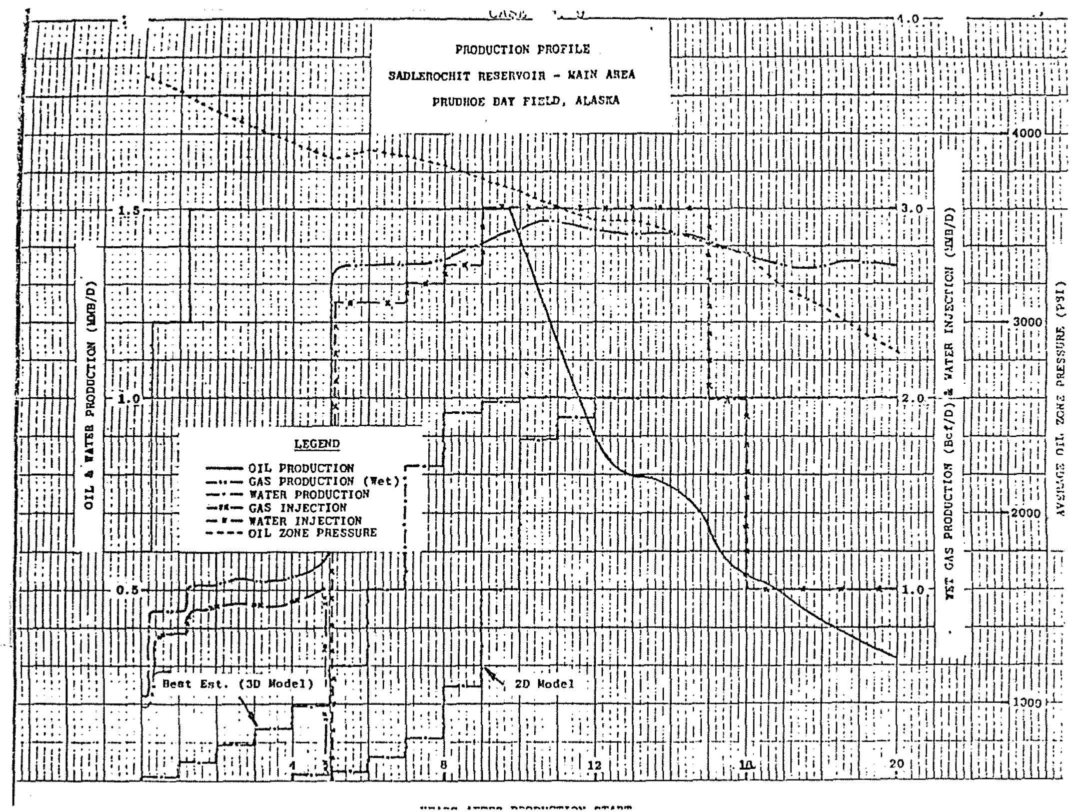

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (BCF/D) & WATER INJECTION (MMS/D)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

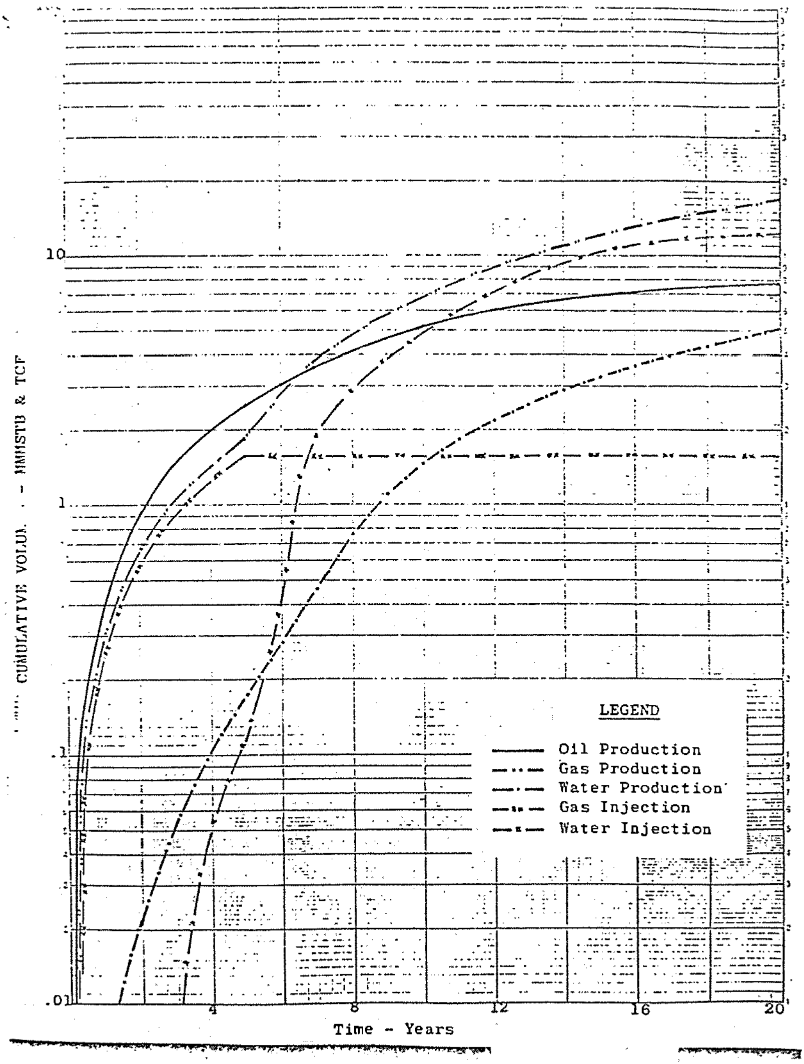

CUMULATIVE VOLUM - MMBSTB & TCF
100
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

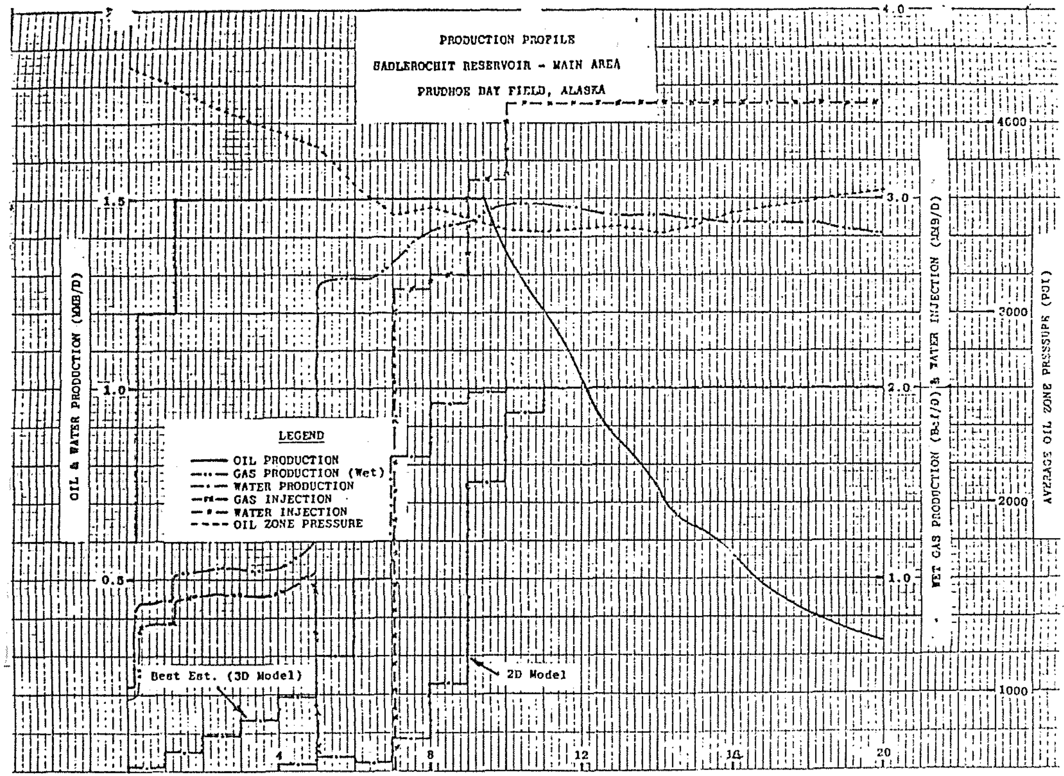

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

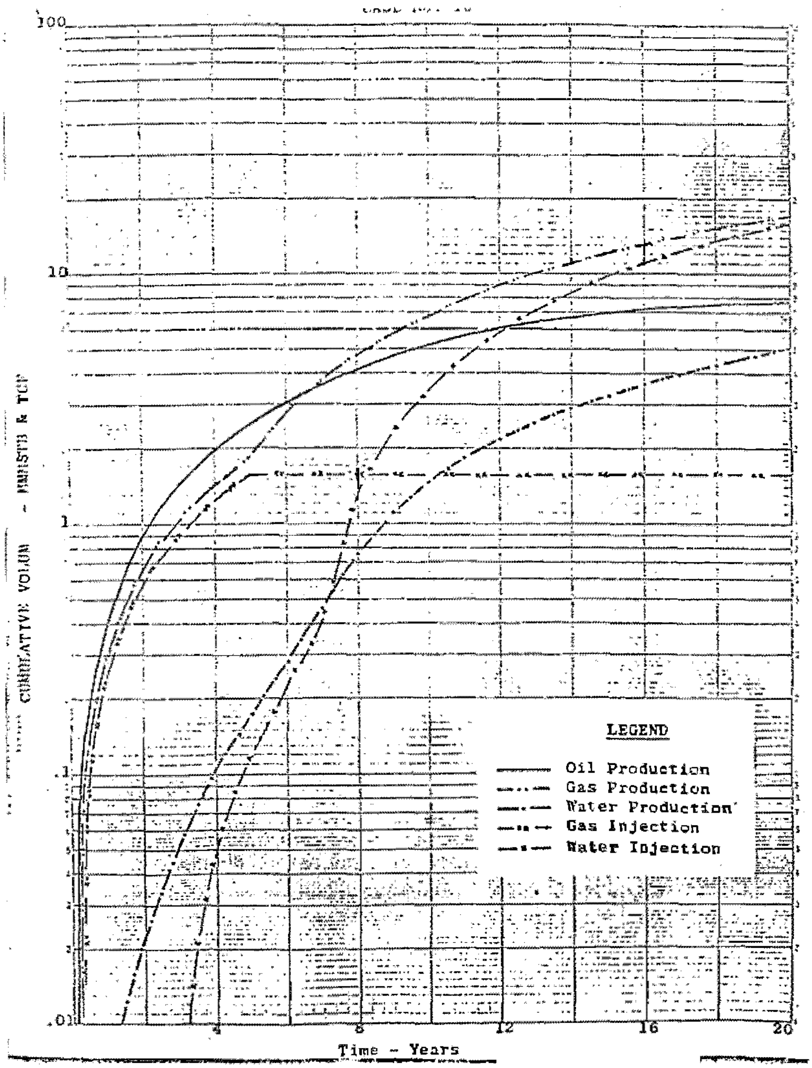


CASE NO. 8
100
10
1
.1
.01
CUMULATIVE VOLUME - MMBSTB & TCF
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

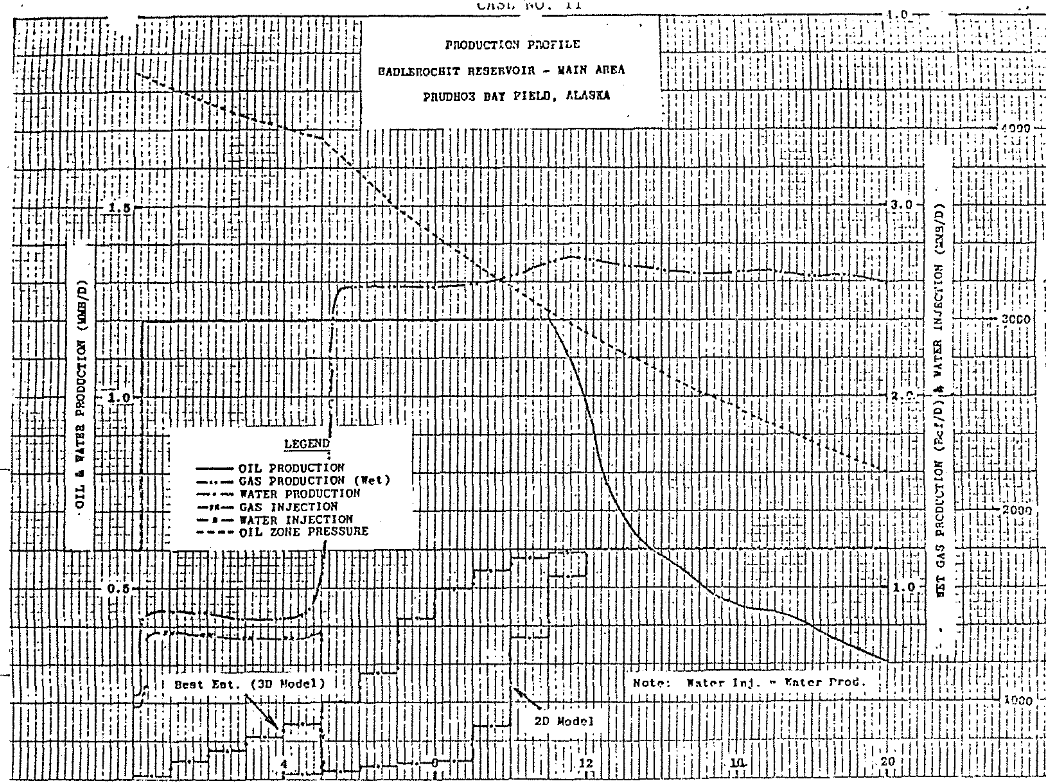

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20


CUMULATIVE VOLUM. - MMMSTB & TCF
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

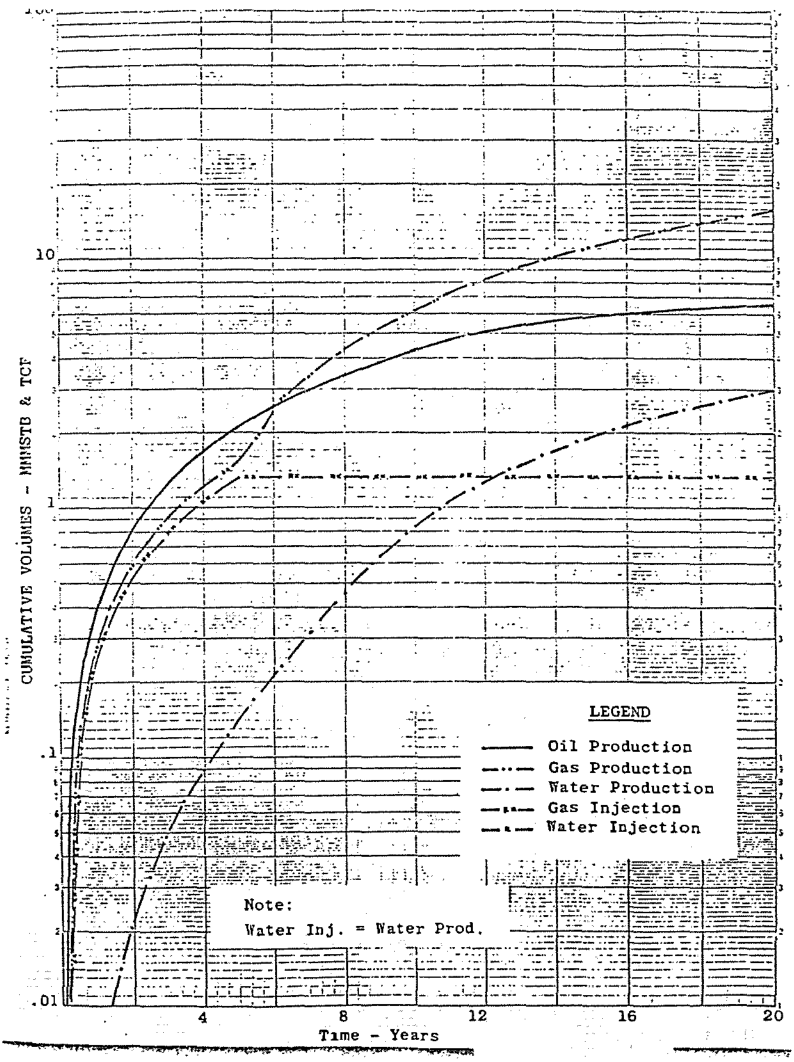

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (BCF/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

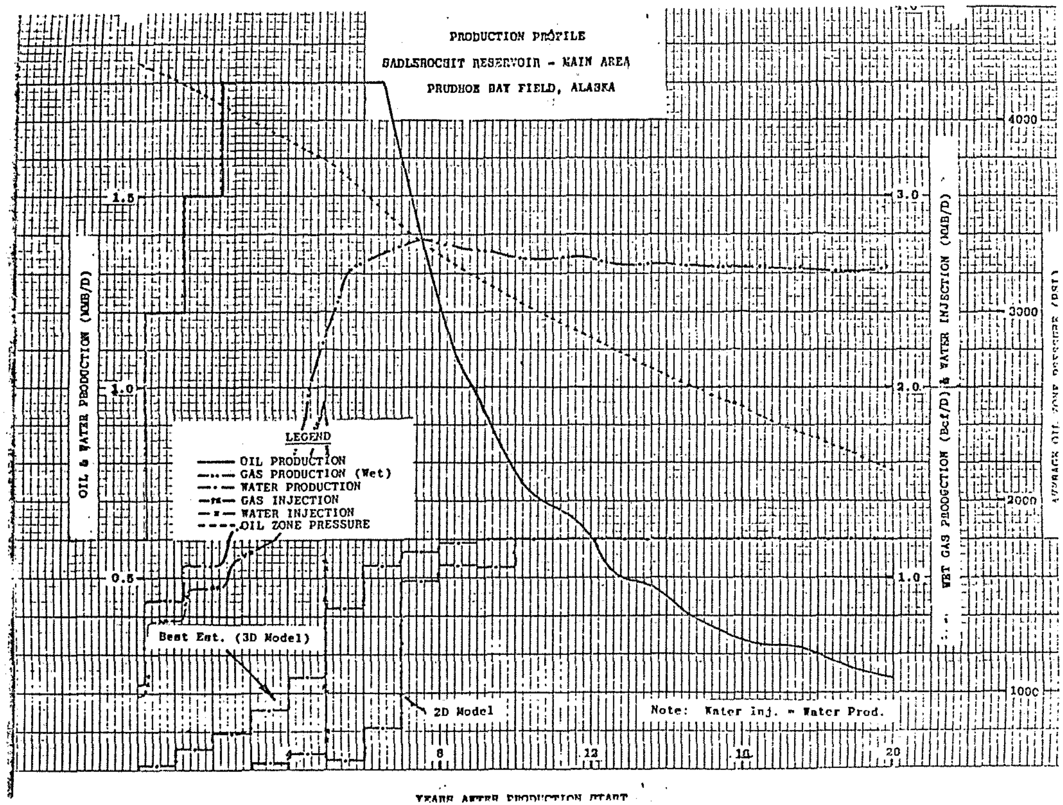

100
10
1
.1
.01
CUMULATIVE VOLUM - MMBSTB & TCF
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

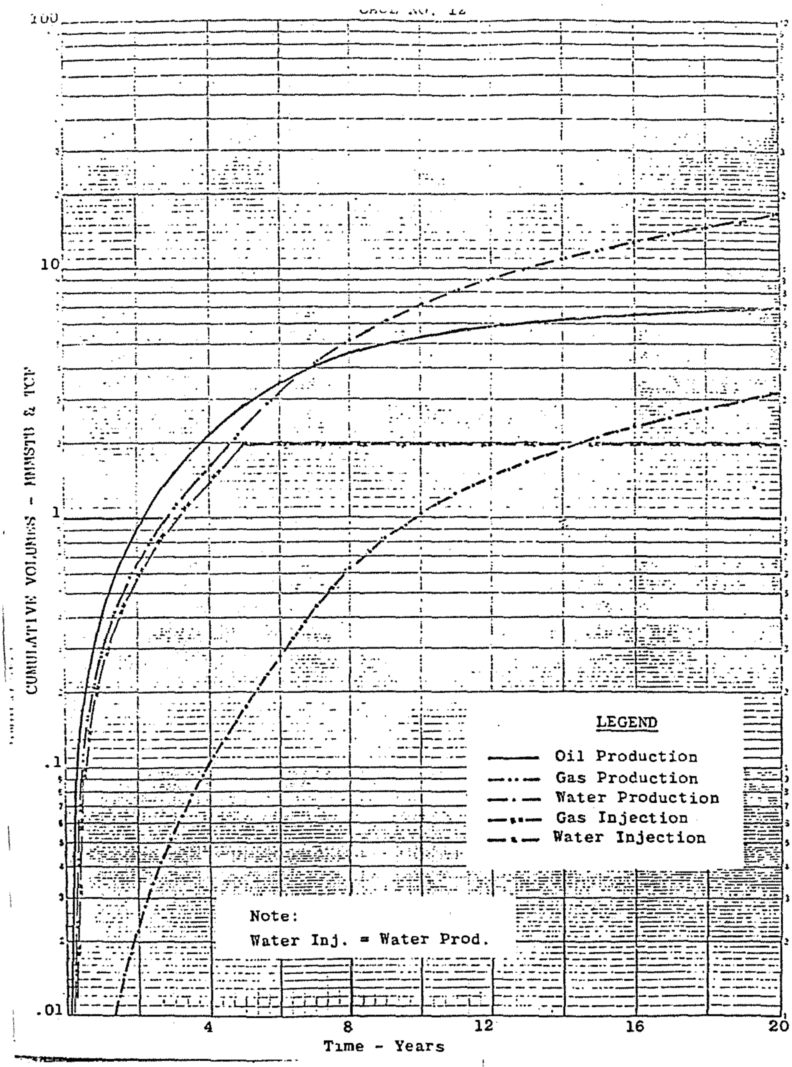
CASE NO. 11



PRODUCTION PROFILE
BADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (MMcf/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: Water Inj. = Water Prod.
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20

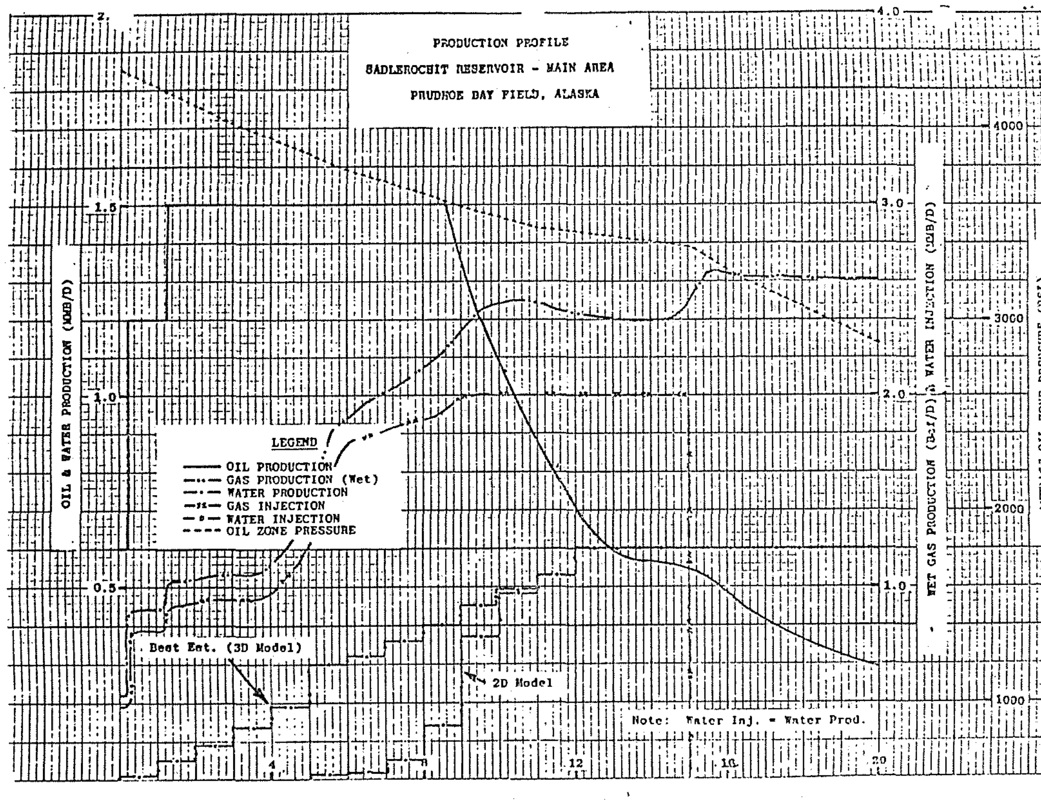

10
1
.1
.01
CUMULATIVE VOLUMES - MMMSTB & TCF
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.

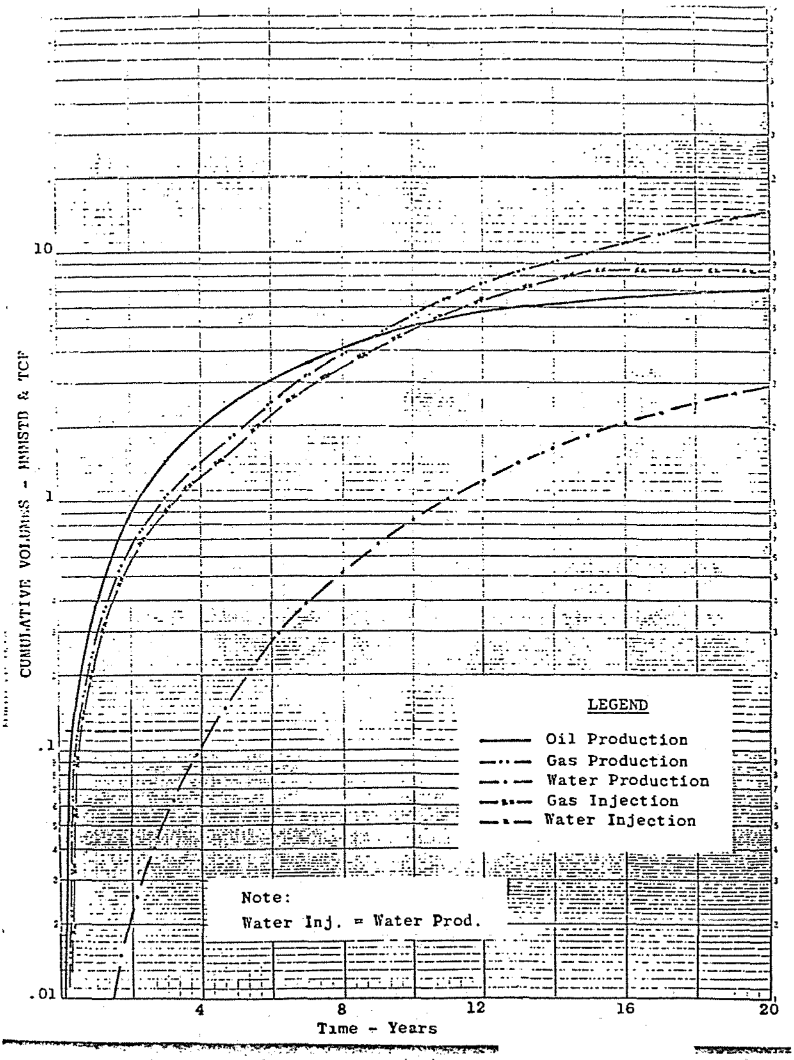

PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
1.5
1.0
0.5
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
3.0
2.0
1.0
4000
3000
2000
1000
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: Water Inj. = Water Prod.
4
8
12
16
20
YEARS AFTER PRODUCTION START



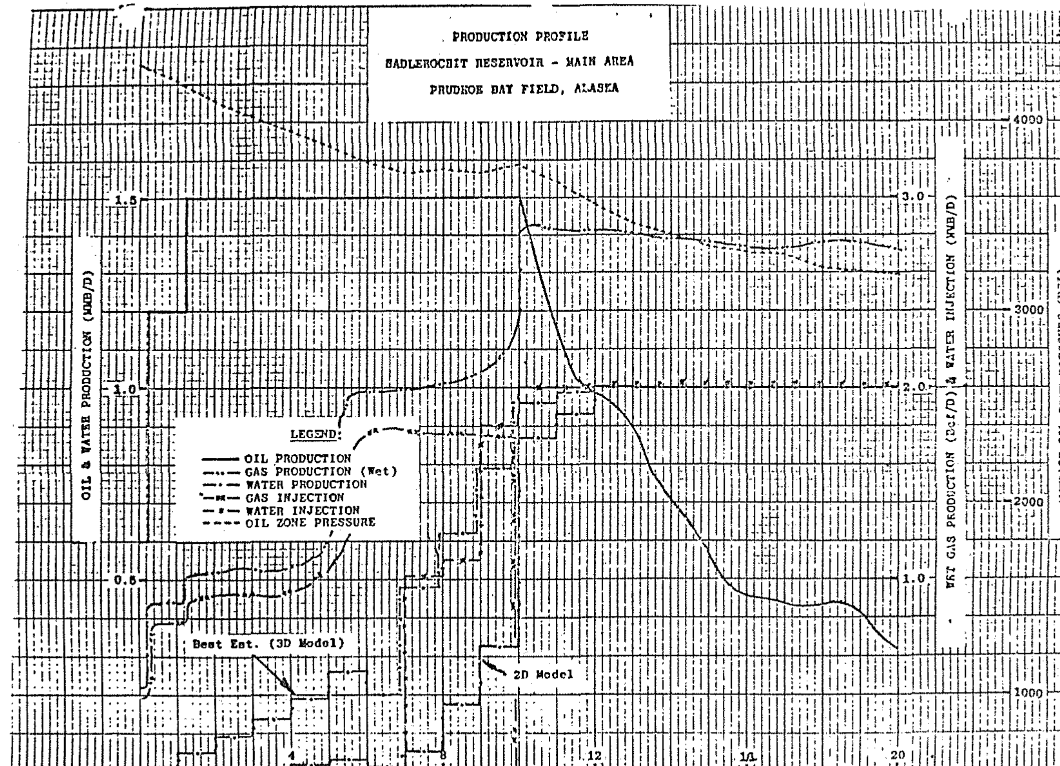
CUMULATIVE VOLUMES - MMMSTB & TCF
100
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.

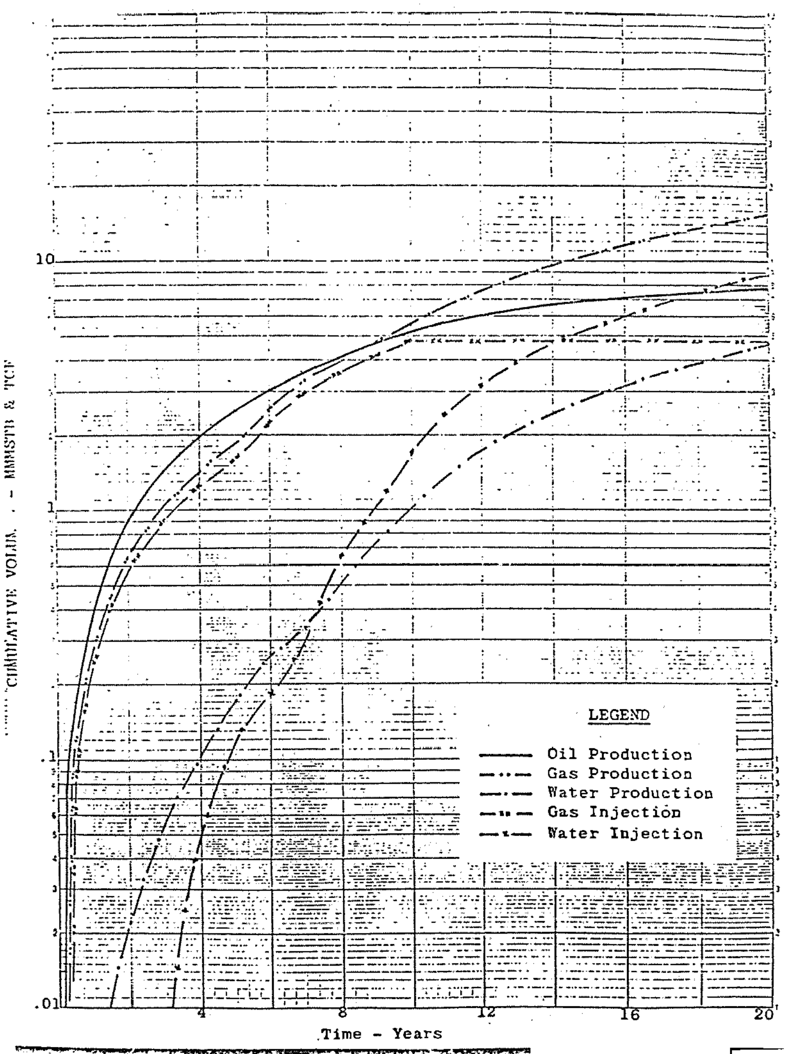
98-069 O - 78 - 53


PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (BCF/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
LEGEND
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
Note: Water Inj. = Water Prod.
2.
1.5
1.0
0.5
4.0
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20



CUMULATIVE VOLUMES - MMMSTB & TCF
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection
Note:
Water Inj. = Water Prod.


PRODUCTION PROFILE
SADLEROCHIT RESERVOIR - MAIN AREA
PRUDHOE BAY FIELD, ALASKA
OIL & WATER PRODUCTION (MMB/D)
WET GAS PRODUCTION (Bcf/D) & WATER INJECTION (MMB/D)
AVERAGE OIL ZONE PRESSURE (PSI)
LEGEND:
OIL PRODUCTION
GAS PRODUCTION (Wet)
WATER PRODUCTION
GAS INJECTION
WATER INJECTION
OIL ZONE PRESSURE
Best Est. (3D Model)
2D Model
1.5
1.0
0.5
3.0
2.0
1.0
4000
3000
2000
1000
4
8
12
16
20



CUMULATIVE VOLUM. . - MMMSTB & TCF
10
1
.1
.01
4
8
12
16
20
Time - Years
LEGEND
Oil Production
Gas Production
Water Production
Gas Injection
Water Injection

October 13, 1977

Honorable Joan Davenport
Assistant Secretary for
Energy and Minerals
Department of the Interior
Washington, D.C. 20240

Dear Madam Secretary:

On September 22, 1977, the President transmitted his recommendation to Congress that the Alcan Pipeline Project be approved pursuant to the provisions of the Alaska Natural Gas Transportation Act. Congress has 60 days to act upon his recommendation.

The Committee on Energy and Natural Resources has conducted four days of hearings on the President's recommendation. At the hearing held on October 12 the Committee received testimony from Dr. Todd M. Doscher concerning the possibility that withdrawal of the gas from the Prudhoe Bay field will reduce the total amount of oil that may ultimately be recovered from the Sadlerochit reservoir. A copy of his statement is enclosed. Dr. Doscher's research on the subject was done pursuant to a contract with the State of Alaska Legislative Affairs Agency. A copy of his final report will be made available next week.

Dr. Doscher recommended that a decision to authorize construction of a gas pipeline from the Prudhoe Bay field to the lower 48 states be delayed for three years in order to allow time to analyze actual field production behavior.

The Committee will hold an additional day of hearings on Tuesday, October 25, to take testimony from the State of Alaska and the North Slope producers on Dr. Doscher's study. We would like to request that you analyze the material available to you on the field's productive capabilities and report the results of that analysis to us. We would appreciate your addressing the following:

1. Assess existing reports and data on the producers' operating plans, and the reliability of such without field operating data;

2. Evaluate the possible effects of gas withdrawal at rates between 1.5 and 2.6 million cubic feet per day correlated with oil production between 1.2 and 2.0 million barrels per day;

3. Evaluate the likelihood of a successful reinjection program, utilizing water or carbon dioxide, instead of natural gas produced from the field; and

4. Recommend what type of production plan appears to be most appropriate to insure the maximum production of both oil and gas over the expected life of the field.

Because of the severe time constraints on Congressional action, we request that you transmit this information to the Committee no later than October 25, 1977. We understand that most of the information we have requested should be readily available due to the Department's evaluation of Alaska gas transportation systems pursuant to Section 6 of the Alaska Natural Gas Transportation Act. Questions concerning this request should be directed to Elizabeth A. Moler, Staff Counsel, at 224-0611.

We appreciate your assistance in this matter.

Sincerely,

Henry M. Jackson, Chairman

John A. Durkin, U.S.S.

HMJ:bmj
Enc.

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

OCT 27 1977

Honorable Henry M. Jackson and
Honorable John A. Durkin
Committee on Energy and Natural
Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman and Senator Durkin:

Thank you for your letter of October 13 concerning production plans for the Prudhoe Bay field. Individuals from the Department of the Interior and contractors to the Department have studied plans for producing oil and gas from the Prudhoe Bay field as part of the December 1975 report to the Congress on the feasibility of transportation systems for Alaska gas (pursuant to Title III of P.L. 93-153) and as part of the agency reports to the President in July of this year (pursuant to the Alaska Natural Gas Transportation Act). I have asked these individuals to address the four specific issues you raise in your letter. Their analysis is enclosed. My staff and I are available to answer any further questions you might have on this important question.

Sincerely yours,

Joan M. Davenport
Assistant Secretary
of the Interior

Enclosure

Gas Production from the Prudhoe Bay Field:
Issues Raised by Senators Jackson and Durkin

The basic question raised by Senators Jackson and Durkin in their October 13, 1977, letter to Assistant Secretary Davenport is: Will the withdrawal of gas from the Sadlerochit Pool of the Prudhoe Bay Field at the rates proposed by the Prudhoe Bay Unit Operators reduce ultimate oil recovery from the Pool? This question is critical to the approval of a gas transportation system from Prudhoe Bay and has been intensely studied by the Department of the Interior during preparation of the feasibility study of Alaska gas transportation systems (pursuant to Title III of P.L. 93-153) and the Report of the Working Group on Supply, Demand, and Energy Policy Impacts of Alaska Gas to the President. Representatives of the Department have conducted and commissioned independent investigations of the issue; have met with the Division of Oil and Gas Conservation of the Department of Natural Resources of the State of Alaska (DOGC), their consultant H. K. Van Poolen and Associates, Inc., and the Prudhoe Bay Unit Operators on many occasions; attended the public hearings on this matter in Anchorage on May 5, 6, and 8, 1977; and have reviewed all public reports and testimony related to this issue.

At this time, there is almost no reason to believe that a significant reduction in ultimate oil recovery will result from gas production at the rates proposed if the field operating practices approved by the DOGC, including massive water injection, are followed. However, Conservation Order No. 145, Prudhoe Bay Field, Prudhoe Oil Pool, by the DOGC states in Conclusion 23, "The offtake rates approved by the Committee, at this time, must be established without the benefit of production history. Therefore, these offtake rates may be changed as production data and additional reservoir data are obtained and "analyzed". Thus the State can order that gas offtake (i.e., gas sold) be reduced or even terminated as additional data is secured if in their judgment gas offtake at the rates proposed is not consistent with sound conservation practices, i.e., would significantly reduce ultimate oil recovery. However, all of the evidence to date indicates that a significant loss in ultimate oil recovery is highly unlikely.

The following will address the four specific issues given in the letter from Senators Jackson and Durkin.

1. The existing reports and data on the producers' operating plans, are the most intense investigation of an oil and gas reservoir ever conducted. The studies by the State of Alaska, the Department of Interior,

and each of the major unit operators, British Petroleum (BP), Atlantic Richfield Company (ARCO), and Exxon Corporation, were independently conducted. They concur on major conclusions and differ only on details.

Field operating data is obviously not yet available. However, the science of reservoir simulation is sufficiently advanced to provide adequate predictions based on the considerable Sadlerochit Pool data available and experience gained elsewhere with similar reservoirs. The producers' operating plans, as approved by the State, provide for continual monitoring and data gathering. As such information is secured the plans can be modified as necessary. The most important variables will be water injection rate and injection well location. Both can be modified as facts indicate. This flexibility is not unique to Prudhoe Bay. Initial operating plans are necessarily developed for oil fields shortly after discovery and continually modified thereafter to maximize economic recovery of oil and gas. The reservoir simulation studies on which operating plans are based, though lacking operating data, are adequately reliable at this time and justify the producers' initial conclusions.

2. Gas withdrawal at rates between 1.5 and 2.6 billion cubic feet per day combined with water injection could increase ultimate oil recovery in comparison with prolonged reinjection of the gas. A natural or artificial water flood is more effective in increasing ultimate oil recovery than a downward movement of the expanding gas cap resulting from prolonged gas reinjection.

An analysis of the effects of these oil and gas production rates leads to the following conclusions:

a) The results of production in this immense reservoir will occur slowly and the data monitoring system that the DOGC requires will enable both they and the producers to detect trends very early.

b) As new information becomes available and is analyzed, oil and gas production rates and water injection rates will be modified to most efficiently produce the reservoir. Adverse effects will be corrected and beneficial effects maximized. If a significant natural water drive is detected in portions of the reservoir, for example, water injection can be limited. The converse would be true. If significant gas cap movement down structure occurs, gas cap production can be decreased. If encroachment of oil into the gas cap occurs, gas injection can be increased. If reservoir pressure departs from predicted trends, offtake of oil or gas can be varied.

c) Oil and gas production and the water injection program for the reservoir and for individual wells will be managed to assure maximum economic recovery.

3. The planned water injection program has a very high probability of being successful. Similar programs in other fields supply adequate prototype information. The design flexibility of the plan supports this opinion. No carbon dioxide injection is planned at this time.

4. The production plan proposed by the operators and approved by the State is an initial plan only. Oil and gas production rates and water injection rates will be modified, increased or decreased, as production continues and reservoir data is secured, as previously discussed. With this flexibility, all of the evidence indicates that this proposed plan will result in the maximum recovery of oil and gas.

Several additional factors should be recognized, however:

a) It is not possible to maximize both oil and gas production simultaneously. The Sadlerochit plan is designed to maximize ultimate oil recovery, but will result in no significant loss in the ultimate gas recovery.

b) Economic factors must also be considered, though they do not influence the proposed plan at this time and will not for a number of years. Oil recovery stimulation programs can be visualized that are too costly to be economical at present crude oil prices or even much higher future prices. At some point in the future they may become economical. The present plan and any variations in it will not preclude subsequent utilization of any enhanced recovery method that is now known.

c) The plan is designed to simultaneously accomplish two objectives to the maximum degree possible. The first objective is to maintain the gas cap - oil band contact at the level it will have reached when (and if) gas sales begins. Gas cap invasion into the oil band would result in gas cap blow-down to some extent; increased gas production from oil wells, which is costly (frequently impossible) to control; and increased use of gas as compressor fuel to reinject produced gas in excess of gas sales.

The second objective is to maintain original reservoir pressure. As a result solution gas will remain trapped in the oil, and oil recovery will thereby be increased. Van Poolen has estimated that reservoir pressure in the oil zone, currently 4,275 pounds per square inch, will be 3,133 psi. at the end of 30 years and will have remained essentially stable for the final 20 years. DOI studies have reached the same conclusion.

To meet these objectives a massive water injection program is planned by the producers and required by the state. The rate currently proposed is 2 million barrels per day (which would be the world's largest flood) which could be increased if required.

October 25, 1977

Mr. O. K. Gilbreth, Jr., Director
Division of Oil and Gas Conservation
Department of Natural Resources
Pouch M
Juneau, Alaska 99801

Dear Sir:

At the Energy and Natural Resources Committee hearing this morning on the Alcan Pipeline proposal questions to be answered in writing were submitted for the Record. I would appreciate your response to the following:

1. In devising an operating plan for Prudhoe Bay, does your goal include maximizing production?

How does your plan do this?

2. Why were there no simulated runs completed by Van Poollen that simulated full pressure maintenance with gas reinjection and maximum water flooding? (Note: Assume Run #10 is not adequate to measure the benefits of water flooding on reservoir pressure.)

3. Has the State required the operators to study the feasibility and need for an early water flood with gas reinjection as a means of maximizing pressure and oil recovery?

If not, why not?

4. The operators are planning a small scale water injection operation in the next 2-3 years to get information on the actual residual oil saturation. If the results of these tests indicate for example, that gas reinjection is necessary to maintain reservoir productivity, what would be done to ensure maximum productivity?

5. Will the Division of Oil and Gas let Dr. Doscher or another petroleum engineer complete more simulated computer runs?

Because of the time constraints, I trust you will submit your answers in writing to the Committee as soon as possible.and certainly no later than Monday, October 31, 1977.

Thank you for your consideration.

Sincerely,

John A. Durkin

JAD/gbw

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

POUCH M — JUNEAU 99811

October 26, 1977

The Honorable John A. Durkin
United States Senator
3230 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Durkin:

This is in response to your letter of October 25, 1977 in which you asked me to respond to five questions concerning the production of oil and gas from the Prudhoe Bay Reservoir.

The Division of Oil and Gas Conservation is not responsible for devising an operating plan for Prudhoe Bay. Our responsibility is that of a conservation agency -- to regulate oil and gas operations to prevent the physical waste of oil and gas in the State and to protect the correlative rights of all interests in an oil and gas pool. We review plans of operation proposed by operators to determine if waste will occur; if we determine no waste will occur, we approve the plan as proposed by the operator. We become involved with determining a rate of production only when we find it necessary to modify a rate proposed by an operator to prevent waste. The van Poollen studies were prepared to assist us in performing this function by allowing us to make a more informed evaluation of whatever operating plan the operators proposed.

(1) No. Our goal is to maximize hydrocarbon recoveries and prevent physical waste. Our conservation statute provides that we may regulate production rates to prevent waste. If an operator's plan of operation meets the criteria, we will not regulate the rates. In the case of Prudhoe, after hearing testimony at public hearing, we approved the operator's plan, which provides for water injection (see our testimony to this Committee) with conditions that gas production not exceed 2.7 billion cubic feet per day and oil rates not exceed 1.5 million barrels per day.

(2) We believe that the water injection rates in Run No. 10 with high reservoir pressures may never be achieved as a practical matter. This was discussed on Page 2 of Report Supplement A (February 1977). Based on world-wide experience, it is common practice to operate a water injection project such as this at a value below original reservoir pressure, hence the runs in Supplement A are considered more realistic and practical.

(3) Again, the State has not issued any order requiring the operators to study the feasibility of, and need for, early water and gas injection. No such order was needed. Because water injection is a standard means of supplementing reservoir energy to achieve maximum recovery, the operators from an early date studied its application to this pool.

At least as early as December 1975, when the preliminary van Poollen report was released, it was clear that water injection would be needed to achieve maximum recoveries. This subject was also explored on the record in the Federal Power Commission proceeding on the Alaska gas pipeline (El Paso Alaska, CP75-96, et al.).

(4) To the best of our knowledge, the project proposed is to determine the water injectivity potential and is not for the purpose of determining the residual oil or gas saturation, nor will it indicate the necessity of gas injection.

(5) Neither Dr. Doscher nor any petroleum engineer to date has requested that the State complete any simulated computer runs. The information needed to complete additional computer runs is either public or in the van Poollen reports, copies of which are widely available. As for use of the existing model by Dr. Doscher or any other petroleum engineer, contractual arrangements between Dr. van Poollen and the owner of the model -- Scientific Software Corporation -- require that anyone other than the Oil and Gas Division obtain permission from the owner of the model to use the existing model. Also, the State will authorize our consultants to permit access to the model provided that Dr. Doscher or the engineer

requesting such runs pay the costs of completing the runs at the customary rates charged by the consultants for this work. Neither the State nor the consultants will be responsible for the results of any such runs.

Sincerely yours,

O.K. Gilbreth per RHL

O. K. Gilbreth, Director
Division of Oil & Gas Conservation

OKG/kc

ISHAM, LINCOLN & BEALE
COUNSELORS AT LAW

1050 17TH STREET, N.W. SEVENTH FLOOR
WASHINGTON, D. C. 20036

TELEPHONE 202-833-9730

CHICAGO OFFICE
ONE FIRST NATIONAL PLAZA
FORTY-SECOND FLOOR
CHICAGO, ILLINOIS 60603
TELEPHONE 312-786-7500
TELEX: 2-5288

October 28, 1977

Ms. Betsy Moeller
Senate Committee on Energy
and Natural Resources
3204 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Ms. Moeller:

At the oral invitation of the Committee, the State of Alaska submits the following comments on the GAO Report which were prepared with the assistance of Dr. H. K. van Poollen and O. K. Gilbreth, Director, Division of Oil and Gas, Department of Natural Resources, State of Alaska:

(1) No comment.

(2) All three firms did not use the van Poollen data in its entirety. Gruy and Core Lab did use the volumetric data of van Poollen available at the time their work was performed. This work was published in June 1974. Subsequent to that time, the van Poollen information was updated to take into consideration additional geological data, and this resulted in increasing the size of the gas cap by 5.3 trillion cubic feet. There was a change in the oil zone information but the reason for this difference is unknown to us.

(a) Sensitivity analyses run by van Poollen indicated a weak aquifer. This same general conclusion was reached by the operators. All studies indicate similar aquifer response.

(b) As indicated above, the gas in place volume used in the van Poollen model runs was slightly larger than used by Core Lab and Gruy. Geological evidence indicates the Shublik formation probably is in communication with the Sadlerochit gas cap. Approximately two (2) trillion cubic feet of the five and three-tenths (5.3) trillion cubic feet added to the gas cap represents Shublik gas. The remaining three and three-tenths (3.3) trillion cubic feet represents a larger gas cap than originally mapped based on geologic data obtained from additional drilling. The operators testified at the Alaska Division of Oil and Gas hearing on May 5, 1977 that the Shublik and Sag River Sandstones are in communication with the Sadlerochit reservoir (hearing transcript pages 49-51 are attached).

The small volume of Shublik gas shown above was the only hydrocarbons outside of the Sadlerochit formation that were included in the van Poollen model runs.

(c) We agree these differences are small: they are within the sensitivity of model runs.

(d) and (e) The production profiles will depend to a significant degree on the assumed operating and work-over program. For example, we assumed that wells would be recompleted as many as two times when making excessive water, then closed in the third time that it happened. This was also done for excessive gas production in a well. However, no more than three recompletions were allowed for any one well. If the well made excessive water or gas after three recompletions, it was shut in. As noted on some of the model runs, the gas/oil ratio limitation was relaxed after thirteen years' production to maintain more oil delivery points. Other studies incorporated similar approaches with slightly different recompletion criteria.

(f) See paragraph prior to 2a. The estimates of hydrocarbons in place available to us are within an acceptable range of engineering accuracy.

(g) The API report includes reserves from certain other reservoirs and condensate not included in the van Poollen report.

(3) The State of Alaska studies included one sensitivity run which indicated a recovery of 42.8 percent. This run was not considered as representative of a reasonable way of operating the reservoir. As pointed out on page 2 of our Report Supplement A (February 1977),

we feel that Runs 10 through 12 may not represent a practical operating condition because of the likelihood of premature water coning (with the possibility of severe damage to the gravity drainage mechanism) and the changes of pushing oil into the gas cap; also, reducing the pressure will result in a free gas saturation which enhances gas recovery by water flood. Run No. 10 was the one which gave 42.8 percent recovery as mentioned in the GAO report. As indicated, our Supplement A runs, which we believe are more representative, give maximum recoveries on the order of 40 percent of the original oil in place.

(4) Since all produced gas will be reinjected until a line is completed, approximately five or more years production of solution gas will be injected into the gas cap. Depending on how one looks at it, the volume of first gas into a pipeline which exceeds the then solution gas can be called other gas cap gas or solution gas. There will be gas withdrawal from the gas cap, but several years will elapse before production lowers the free gas volume to the volume originally in place. Gas production rates of 2.7 Bcf/d which should yield approximately 2 Bcf/d gas sales should not require oil rates in excess of 1.5 million barrels per day. The volume of 2.4 Bcf per day apparently includes gas from other reservoirs than the Sadlerochit reservoir.

(5) We agree.

(6) Our studies were made to determine the performance which could be expected from the reservoir. The figures on liquid recoveries are dependent on pipeline specs and were not part of these studies.

(7) Same as 2(e) and (f).

Some of the issues not addressed by Mr. Doscher when considering the possibility of converting the existing TAPS line to a two-phase operation are:

(1) Is the current line designed to withstand the vibration and surge forces that would exist with two-phase flow?

(2) Would the installation of equipment necessary for the conversion of the line to two-phase flow require an extensive shut-down of the Prudhoe Bay field?

(3) What would be the impact on exploration and the development of any new fields if the TAPS line could not handle very large crude oil volumes while operating as a two-phase line?

(4) If additional fields are discovered and the oil pipeline continues to operate at rates of 1.5 to 2.0 million barrels per day, two-phase flow would not be possible at these rates and, hence, there would be no means to blow the Prudhoe Bay field down and there will be a sizeable loss or delay in recovery for many, many years.

(5) What happens if a large discovery is made in NPR-A?

(6) What if two-phase shipment is found impractical?

Any questions with respect to this matter should be directed to the undersigned.

Respectfully submitted,

Robert H. Loeffler

Attorney for
The State of Alaska

RHL/kc
Attachments

The Sadlerochit contains the bulk of the hydrocarbon reserves in the pool and hence has been reviewed in detail. We will now review the younger portions of the reservoir more briefly.

On your right is the type log seen previously, and on your left is an isopach map of the Sag-Shublik interval. The dark red is greater than 120 feet, light red, 80 to 120 feet, orange, 40 to 80 and yellow, zero to 40. The map shows that the Sag-Shublik is present throughout the area, except where truncated, but is thin relative to the Sadlerochit sandstone.

The Shublik formation, which has a thickness of seventy feet, was deposited on top of the Sadlerochit sandstone. It is composed of a complex sequence of interlayered marine shales, silts, sandstones, phosphates, and phosphatic limestones. These phosphates and phosphatic limestones are sporadically porous throughout the field area and serve as the main reservoir interval for the Shublik. They are in direct fluid communication with the Sadlerochit reservoir, either vertically or horizontally across faults and thus retain the same fuild contact.

The Sag River sandstone overlies the Shublik formation. It consists of very fine to fine grain marine sandstone, which have an average thickness of thirty feet. It is interpretted to be in direct fluid communication with the Sadlerochit via faulting and consequently has the same fluid contacts.

The youngest portion of the reservoir is the newly discovered Put River sandstone, which is a conglomeratic sandstone deposited in Lower Cretaceous times.

The slide on the left is an interpretive isopach map showing the thickness and aerial distribution of the sand, as interpretted from well control and shown by the green dots. The yellow represents less than twenty feet of sandstone, the orange represents twenty to forty, and the red represents greater than forty feet of sandstone. The sandstone has a maximum thickness of sixty-eight feet in NGI-1. The map shows that this unit is an elongated sandstone body, possibly representative of a channel or trough infill.

The slide on the right is a cross-section, located along the line of section on the map. This cross-section shows the relationship of the Put River sandstone with the main reservoir interval. Note that in NGI-6 and NGI-7, the sandstone is in direct contact with the Sag River sandstone.

The Put River sandstone has not been tested, however, as a result of the direct contact between the Sag River sandstone and the Put River sandstone, we conclude that they are in direct communication and that the Put River sandstone is gas-bearing in the pipe area.

For these reasons, the working interest owners are asking for an amended definition of the vertical limits of the Prudhoe Oil Pool to include the Put River sandstone and other similar gas or oil reservoirs discovered in the future.

You have seen that the Prudhoe Oil Pool consists of hydrocarbons in a complex series of predominantly sandstone reservoirs which have common fluid contact and which are entrapped by a faulted and truncated asymmetric anticline. The reservoir configuration, distribution of hydrocarbons and rock properties will be shown in the following presentation to have significant effects on reservoir volumes, reservoir management and waterflood planning studies.

October 25, 1977

Dr. H. K. Van Poollen
H. K. Van Poollen & Associates, Inc.
Littleton, Colorado

Dear Dr. Van Poollen:

At the Energy and Natural Resources Committee hearing this morning on the Alcan Pipeline proposal questions to be answered in writing were submitted for the Record. I would appreciate your response to the following:

1. In the course of completing your work for the State, did you ever have contact with the State, or the operators, that could be construed as pressure or an effort to influence the findings or results of your work?

If yes, could you please be specific.

2. In your analyses, oil recovery declines from almost eight billion barrels (41%) to about 6 billion barrels (32%), as gas sales are increased from 2 to 3 and then 4 billion cubic feet a day. If this is extrapolated what would you suggest is the oil production with no gas sales?

3. Could you also comment on the finding by Core Laboratories that maximum oil recovery of 8.36 billion barrels is with no gas sales?

4. Why are the total oil production figures of nearly 8 billion barrels significantly lower than API's estimated recoverable figure of 9.6 billion barrels?

Because of the time constraints, I trust you will submit your answers in writing to the Committee as soon as possible, and certainly no later than Monday, October 31, 1977.

Thank you for your consideration.

Sincerely,

John A. Durkin

JAD/cbw

H. K. VAN POOLLEN AND ASSOCIATES, INC.

1100 WEST LITTLETON BOULEVARD
LITTLETON, COLORADO 80120
TELEPHONE: 303 795-8578
TWX: 910 935 0102
ANS: HKVANPOOL LITL

1977 OCT 28 PM 2:56

October 26, 1977

The Honorable John A. Durkin
United States Senator
3230 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Durkin:

I appreciate the questions you posed in your October 25, 1977 letter to me. My answers are as follows:

(1) The State and I worked together. We had occasional meetings with operators to discuss general parameters. In all of these meetings I have never seen any pressure brought upon me which was intended to influence my professional opinion.

(2) The numbers quoted in your letter are based on our January, 1976 report. That report indicated that excessive gas sales are detrimental to recovery. Extrapolation to zero gas sales would give approximately 41.4 percent to 42.75 percent oil recovery. However, as indicated in our Supplement A dated February, 1977, these operational procedures were considered inconsistent with common oil field practice. Hence, a more realistic value for zero gas injection with water injection is our Run 9A which results in a recovery of 39.5 percent. A fair comparison for cases having an offtake rate of 1.5 MMbbl. of oil per day, water injection resulting in a final reservoir pressure in the order of 3150 psi, would be as follows:

Run	Gas Sales Bcf/Day	Oil Recovery Percentage
9A	0.0	39.5
8A	1.5	40.1
3A	2.0	40.9
4A	2.25	40.0

Differences in values in these ranges are inconsequential.

(3) Core laboratories had a higher oil in place number, or 19.5 MMMbbbls. versus 19.1 MMMbbls. for ours. Their maximum value gives the same recovery of 42.8 percent as our maximum value.

(4) The API report included additional reservoirs to ours.

Should you or anyone on your staff wish to discuss any of these matters or related ones in more detail, please feel free to contact me.

Sincerely yours,

H K van Poollen

Dr. H. K. van Poollen

HKvP/kc

Statement

by

Howard Boyd, Chairman
The El Paso Company

I have asked to speak in the early stages of these proceedings because my statement may have material bearing on the character and length of the proceedings. What I have to say does not come with ease.

El Paso sponsored a project to market Alaskan gas by an all-American route convinced that the overall national interest would thereby be best served. We are today unshakingly convinced of the wisdom of that view, but our judgment is not determinative of the issue.

The President of the United States, exercising the responsibility reposed in him by this Congress, has selected a different project, and his decision is now before the Congress for ratification. Human emotion tempts me to describe the benefits which we visualized in our project, but political reality tells me that further proceedings before this Congress, followed by such judicial review as may be available, does not enjoy sufficient prospect of success to justify the harm to the public interest inherent in such a course.

Above all else, Alaskan gas is needed in the lower 48 states at the earliest practicable date. To that end, let the sponsors of the trans-Canadian project commence their efforts to finance and get on with the project.

Let me add that although our project did not succeed, I take pride in the fact that it made possible improvements of a significant nature in the project now recommended to Congress. Moreover, El Paso has developed a great body of expertise and substantial engineering and environmental data which can be of assistance to the project and which we are prepared to make available to it.

In conclusion let me take this occasion to express our deep appreciation to those people, including members of the Senate and House who, sharing our view, have vigorously supported us during the long proceedings to this point.

Statement of Jerry McCutcheon, Anchorage, Alaska

The premature construction of a gasline is totally unwarranted from the standpoint of cost to the United States consumer and from the standpoint of good reservoir management. It is not in the long term interests of the United States or the State of Alaska. The highest and best use of the natural gas for the next decade is for the pressure maintenance of Prudhoe Bay.

Early gas withdrawal will result in a loss of 1.6 to 2.5 billion barrels of oil recovery, the average of which is equal to all the oil found in the United States from 1970 through 1976. The sacrificing through a premature construction of a gasoline of 2 billion barrels of oil recovery is like the sacrificing of 20 giant oil fields, or 2,000 significant oil findings. Secondly, enhanced recovery techniques could result in an additional 6 billion barrels of oil recovery. When combined with the above, they may more than double the proposed current oil recovery from the 20 billion barrel Prudhoe Bay Oil Pool. The total additional recovery could exceed all of the discoveries in the next one to two decades in the south 48 states. Third, the investment in an Alcan gasline from Alaska would be equal to 60 percent of all the investment in all the gaslines built in the United States to date—for the delivery of only 4 to 5 percent of the national gas supply. The cost of gas delivered from Alaska would be equal to six or seven times the free market price of gas, and would raise the price of all gas sold in the United States by 50 cents per thousand cubic feet.

THE CORE LABORATORIES INC. REPORT PREPARED FOR ALCAN PIPELINE COMPANY

We find with the production of 1.6 million barrels per day with no aquifer (the underground water whose influx helps keep pressure in the reservoir), no water injection, and no gas sales, the recovery of Computer Run No. 1 is 6.53 billion barrels of oil. In Run No. 2, with the addition of aquifer, with other conditions being the same, oil recovery rises to 7.61 billion barrels of oil, or just over a billion barrels of oil for the aquifer.

The report unfortunately does not give the amount of water that the aquifer contributes, but this additional oil recovery stresses the significant effect that can be had for early water injection.

The injection of half a million barrels of water, with other condtiions being the same, for Run No. 2 raises the recovery 750 million to 8.36 billion barrels of oil in Run No. 3, which is the highest recovery of any of the Core Lab computer runs.

What the recovery would have done had the pressure been kept above the bubble point in the early years of production one can only infer, for Alcan did not produce a standard run against which one can measure other methods of production.

The small amount of aquifer was worth a billion barrels of oil, and 0.5 million barrels of water injection was worth ¾ of a billion barrels of oil recovery even though it was not started until 6 years after oil production began. Therefore it is not unreasonable to believe that had such water as necessary been injected at the beginning of oil production, oil production would be between 9.1 to 9.6 billion barrels of oil, and approximate the DeGolyer & MacNaughton report of 9.6 billion barrels of oil, which the Prudhoe Bay operators use in their television promotional ads. The attached graph shows 9.1 billion barrels of recovery.

If Alcan had computer run(s) that could be used as standards against which other runs could be measured, and if those runs showed little or no loss of oil recovery would result from early gas sales and late water injection, then it is reasonable to assume that Alcan would have used those runs to prove Alcan's case. Further, in the absence of the runs which could be used as standards, one can conclude, because of their obvious importance, that either they were done and are now being withheld or that it was known ahead of time that runs of full pressure maintenance as standards would be damaging to Alcan's case for gas sales, and therefore were not done.

Core Lab's Run No. 4 is for 2.25 bcfd (billion cubic feet per day) of gas sales, which must be corrected. A later finding showed that more reservoir gas must be withdrawn to obtain the same specific amount of pipeline quality gas. Core Laboratory originally used 2.373 bcfd of reservoir gas to obtain 2 bcfd of sales gas. Now it is accepted that 2.7 bcfd are required for 2 bcfd of sales gas. Thus the 2.25 bcfd corrected is a little less than 2 bcfd of sales gas and results in 1,850 million barrels of lost oil recovery, even though 10,260 million barrels more water were injected than in Run No. 3 in an attempt to compensate for gas production.

Comparing Run No. 4 to Run No. 2, no water injection but 90 percent gas reinjection, the gas sales of Run No. 4 resulted in the loss of oil recovery of 360 million barrels, even though Run No. 4 received 17 billion barrels of water injection that Run No. 2 did not receive. The water injection could not compensate for gas withdrawal.

Run No. 16 is only about 1 bcfd of sales gas, yet there is a loss of oil recovery of 1,420 million barrels, as compared to a corrected Run No. 3.

We can see that the Prudhoe Bay Oil Pool is very sensitive to gas withdrawal and to early water injection for pressure maintenance. Further, that water injection cannot compensate for gas withdrawal even if the withdrawal is small. Oil recovery loss appears to be proportional to gas withdrawal.

Now if we approximate the amount of gas sales, 2.4 bcfd, which Alcan says is the absolute minimum, we must use Runs Nos. 14 and 20 with recovery of 6.63 and 6.71 billion barrels of oil respectively. The lost recovery from corrected Run No. 3 is 2.5 billion barrels of oil. That is 25 percent greater than the amount of oil that was found in the United States from 1970 through 1976. To sacrifice 2.5 billion barrels of oil is like sacrificing 2.5 giant oil fields every year for the next ten years.

The van Poollen report was done for the State of Alaska Division of Oil and Gas. Run No. 2 of the van Poollen report is similar to Run No. 1 of the Core Lab report: no water injection, no aquifer, and no gas sales. Yet van Poollen obtained 800 million barrels more oil recovery, a very substantial difference—10% of the expected recovery of the operators' plan.

Van Poollen's Run No. 10 is similar to Core Lab Run No. 3 and obtained similar results. However, van Poollen must use an additional 4 billion barrels of water injection.

Comparing van Poollen's Runs No. 7 and No. 1, the addition of aquifer produces a negligible result. However, the aquifer was worth a billion barrels in the Core Lab report. A later van Poollen run (No. 2A) seems to contradict van Poollen's earlier results because a small amount of produced water was reinjected for an additional 250 million barrels of oil recovery.

The van Poollen report does not have the necessary standard runs, and again it is not unreasonable to assume that they were withheld or not done because the standard runs would have shown that gas reinjection and early water injection with pressure maintenance above the bubble point was essential. Requests for these runs as standards were ignored when the second series of run were done.

Using No. 10 as the closest run to a standard, and comparing it to Run No. 7, we have a difference of more than 1 billion barrels of additional oil recovery for No. 10 with water injection.

Comparing No. 10 to No. 16, which has corrected gas sales of 1.76 bcfd, No. 16 has 1.25 billion barrels less oil recovery.

Comparing No. 16 to No. 20, which is similar except for some operating conditions, No. 20 has an additional 410 million barrels of oil recovery.

Correcting No. 10 for these improved operating conditions by adding the difference between No. 16 and No. 20, we have 8.6 billion barrels of oil recovery.

When we examine Runs Nos. 20–21–22, we see that higher oil production results in higher oil recovery. This is because the water injection is 125 percent of the oil production rate, and this results in additional water being injected into the reservoir. The additional water is worth 500 million barrels of oil recovery. Adding the .5 billion barrels of oil recovery to Run No. 10, we now have 9.1 billion barrels of oil recovery. Run No. 10 also has 4,300 pounds of pressure, which when blown down would add an additional oil recovery, and the oil recovery would approach the DeGolyer & MacNaughton recovery of 9.6 billion barrels.

The 9.6 billion barrels recovery is used by the oil companies in their advertising campaign. The 9.1 billion barrels agrees with the graph.

Comparing the corrected Run No. 10 to Run No. 26, we have 9.1–7.74, or 1,360 million barrels of lost oil recovery for 1.76 bcfd of gas sales. The lost oil recovery rises to 1,650 million barrels of oil in Run No. 28, with corrected gas sales of 2.6 bcfd. Since 2.4 bcfd is the absolute minimum required for the gas pipeline, we must extrapolate between Runs 26 and 28. This gives us about 1.6 billion barrels of lost oil recovery.

ENHANCED RECOVERY

Professor Doscher suggested enhanced recovery by CO_2 flooding may add additional 6 billion barrels of oil recovery, of which 2 billion barrels would be consumed to produce CO_2 for the flooding. If other sources of CO_2 could be used, such as the abundant coal supplies on the North Slope, or if reservoirs of CO_2 could be found, then the full 6 billion barrels would be available.

Considering the fact that the Prudhoe Bay Oil Pool is 20 billion barrels, that Shell Oil Company recently announced a CO_2 flood for 90 percent recovery was expected, and that AMACO announced a flue gas project with 77 percent recovery, the 6 billion barrels is certainly within reason, and the professor may have even understated the potential trying to be conservative. Whether CO_2 is used or some other tertiary method of recovery is used, the possibility of proper secondary recovery plus tertiary recovery may double the recovery of oil from the Prudhoe Bay Oil Pool.

Thus it is quite evident that the premature construction of a gasoline is totally unwarranted from the standpoint of cost to the American consumer and from the standpoint of good reservoir management. It is not in the long term interests of the United States or of the State of Alaska. The highest and best use of the natural gas for the next decade is for the pressure maintenance of Prudhoe Bay.

[Western Union Telegram]

VALDEZ, ALASKA, *September 21, 1977.*

Hon. HENRY A. JACKSON,
Chairman, Energy and Natural Resources Committee, Dirksen Senate Office Building, Washington, D.C.

The city council is concerned about the proposed route of the natural gas line from Alaska. It is imperative that the U.S. economy be kept at a better level than it is now. The gas comes from Alaska for those in the lower forty eight States and we should see that those who pay for it also receive the side benefits of the jobs it will produce. We urge you to support the all American gas route to make jobs for U.S. citizens instead of Canadians. We request this telegram be read during committee hearings and made part of the records.

We urge you as Governor of the State of Alaska to support this position. Thank you.

LYNN CHRYSTAL,
Mayor, city of Valdez, Alaska.

WESTERN UNION TELEGRAM,
Anchorage Alaska, September 22, 1977.

Senator HENRY M. JACKSON,
Chairman, Energy and Natural Resources Committee, Dirkson Senate Office Building, Washington, D.C.

You have been asked to ratify President Carter's choice of a gas line from Alaska through Canada to southern markets.

As you may know, our organization has been deeply involved in the gas line issue for more than 2 years. Almost a million dollars of OMAR contributions and personal expenditures of its members have been committed toward keeping the gas line totally within U.S. borders.

The Alcan project offers Alaska some benefits, most important of which is use of the State's royalty gas from Prudhoe Bay. So you can be confident Alaska's interests are to a great extent protected with the Alcan project if it is built in a timely fashion.

We believe strongly, however, that the interests of the United States are not protected in the agreement between President Carter and Prime Minister Trudeau. Unfortunately we did not have an opportunity to review detailed conditions and implications of the agreement. But based on the agreement summary, we fear it may not adequately address United States avenues for recourse in the event of Canadian delays, delays we think are inevitable.

The Canadian Government says it will not commit tax dollars to the Alcan project in the event of delays and cost overruns (projected by its own national energy board to be at least 32 percent). This, then, leaves the responsibility for bailing out the project to our Government or the U.S. gas consumers or both.

For the privilege of running the line through Canada we would agree:

(1) to largely fund, including cost overruns, a line from Whitehorse north to Dawson, Y.T., solely for Canadian use;

(2) To transfer some DLRS 20 billion of associated economic benefits to a foreign economy at the expense of our own;

(3) To allow Canadian content for materials and labor to be 90 percent, even though the project would be largely funded by U.S. capital, and to let Canada maintain corporate control of the project;

(4) To meet unspecified present and future demands of the Yukon Territory and three autonomous provinces.

We feel the major force for a trans-Canada line, i.e., that it would cement U.S.-Canadian relations and set the stage for future cooperation in other joint endeavors, will ultimately result in even greater deterioration in our relations with Canada.

Two of numerous other examples remind us that continentalist attempts to jointly develop resources cannot be assured of trouble-free implementation: One concerns the Ross Dam negotiations which began in 1941 and are not yet concluded. Another concerns the St. Lawrence Seaway negotiations which took more than 60 years.

If even remotely similar delays occur in bringing Alaska's natural gas resource to other States, our Nation will experience needless suffering.

We urgently request your support of the all-U.S. proposal of El Paso. It is our opinion that a vote for the trans-Canada line is in the best interests of Canada to the detriment of the United States.

ROBERT W. FLEMING, *President.*

○

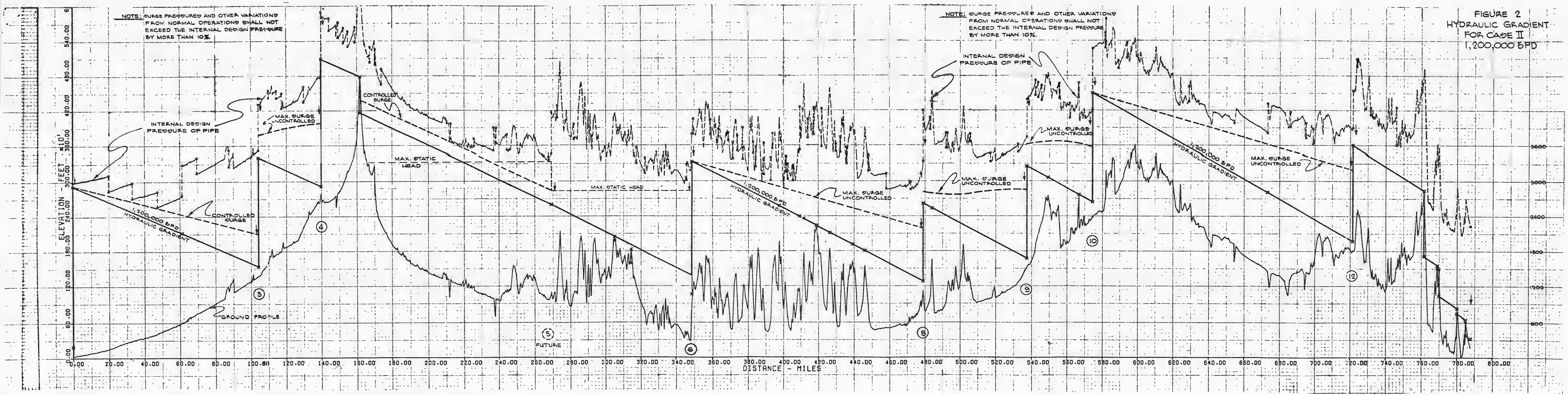


FIGURE 2
HYDRAULIC GRADIENT
FOR CASE II
1,200,000 BPD