SCOMM

#14:2

FULLER

PRUDHOE BAY RESERVOIR MANAGEMENT HEARINGS
August 6 & 7, 1979 - Juneau, House Resources

QUESTIONS
for Producers

1. The history of oil production both nationally and worldwide is not encouraging in that physical waste was long the rule rather than the exception. What specific reassurances can the industry give us that such will not be the case with the Prudhoe Bay reservoir?

2. Have producers done an economic analysis of the cost of waterflooding? By that, we mean what are the capital and operating costs of waterflooding? What are the most likely benefits in terms of oil recovery? What is the discount rate that you are going to use to relate those future benefits to present costs? Is there a time limit beyond which it would be no longer profitable to waterflood from the producers' point of view? If so, when is that time limit?

3. Given the different discount rates used by the State and the oil industry, what might be a profitable investment from the State's point of view may only be a marginal investment from industry's perspective. Is there any way, then, of alleviating this potential conflict regarding secondary recovery at Prudhoe Bay?

4. Would a slower rate of production impact secondary recovery methods? What effect would a slower rate of production have on ultimate oil recovery?

5. What is the timetable for decisions and actions on secondary recovery methods? What results do you expect from using these methods in terms of increasing oil recovery?

6. The Alaska Oil and Gas Conservation Commission reported coning of certain ARCO wells which have subsequently been shut down. Why did the coning occur? What damage resulted to the field? Would a slower production rate for those individual wells have prevented the coning?

7. Even if mid-1984 remains the target date set by industry for waterflooding to begin, why isn't construction of the project begun sooner? Isn't this project, like other capital-intensive projects, going to cost more and more as the years pass? Will the waterflooding project construction create construction jobs? How many?

AGO 532493

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

HALLORAN

STATE OF ALASKA
THE LEGISLATURE

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LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS
October 31, 1978

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Compiled by Kay Brown, Research Analyst

ALASKAN NORTHWEST MAY BE FORCED TO SEEK FEDERAL FINANCING FOR GAS PIPELINE

The Alaskan Northwest pipeline consortium says it will not be able to secure private financing for the Alaska Highway gas pipeline if a proposed "incentive rate of return" rule is adopted in its present form.

In comments filed in early October with the Federal Energy Regulatory Commission (FERC), Alaskan Northwest said rulemaking on the incentive rate of return has had "a chilling effect" on the project and brought financing negotiations "to a standstill."

The partnership also said it may limit its equity contributions to the project unless "major risks and uncertainties" are resolved in its favor.

Imposition of the incentive rate of return would allow the pipeline companies and other equity investors to earn a high rate of return if the project were constructed within or under budget, but would reduce earnings if the project ultimately cost more than projections. The greater the cost overrun, the lower the allowed rate of return would be.

This method for controlling cost overruns was mandated in the President's Decision and Report to Congress selecting the Alcan route over the El Paso and Arctic proposals, but its specific structure and method of implementation were left for FERC to resolve.

FERC issued its first incentive rate of return (IROR) proposal May 8. After receiving comments from 24 interested parties, the commission issued a revised proposal September 15.

"A Commission order retaining any substantial vestige of the September 15 structure will be incompatible with private sector financing of the project," Alaskan Northwest said in its response to the revision. "Alaskan Northwest's plans for private financing cannot be realized under the Commission's proposal. A final rule incorporating the September 15 structure will produce such a fundamental change in the economic parameters of the project that Alaskan Northwest will have no chance to obtain private financing and will be required to seek federal government financial assistance and support."

FERC's September 15 incentive rate of return proposal sets out a complicated method for arriving at the allowed return to equity, and for illustrative purposes suggests this rate of return might be about 17 percent with a 30 percent cost overrun. (FERC says the actual permissible rates of return will be determined in a later evidential proceeding.) A normal rate of return on a regulated pipeline of similar operating risk is about 13 percent, according to FERC.

While the allowed rate of return is quite high if the project is built within or under budget, investors may perceive the risk of huge overruns as so great that they will be unwilling to invest in the project.

In its comments, Alaskan Northwest said FERC's current IROR proposal subjects the partnership to a penalty for all project delay, whether or not caused by the partnership.

Government-caused delays, for which the partnership says it is not responsible and should not be penalized, include the legislative stalemate over natural gas pricing, which already has delayed the project for more than a year; FERC delay in resolving the incentive rate of return; inaction by President Carter and Congress on the appointment and confirmation of a Federal Inspector; and lack of a decision on pipeline design and pressure.

ALASKA'S POSITION VS. NORTHWESTS

"Any variable rate of return mechanism which imposes the financial burden of government-caused delay on equity participants by reducing their allowed rate of return is a system which precludes equity financing," Alaskan Northwest said.

Alaskan Northwest also objected to "an extraordinary degree of reliance by the Commission on Alcan's March 1977 cost estimates as the basis for establishing the variable rate of return structure." Alaskan Northwest maintained that the incentive rate of return should be based on the capital cost estimates submitted to and accepted by FERC immediately prior to certification.

FERC has failed to act with "expedition and certainty" in its rulemaking, Alaskan Northwest said, since additional proceedings and hearings will be required at unknown times in the future in order to finally resolve the range of permissible return and other matters.

"It is without exaggeration that we say that the Commission has given us nothing upon which we can rely at this time," the partnership said. "The actual impact of the IROR structure remains unknown and unknowable."

The State of Alaska, in its comments on the September 15 proposal, did not oppose the IROR formula but did ask FERC to speed up its proposed timetable of proceedings.

"As all those intimately concerned with the gas project know, the issues involved are complex and difficult and the Commission has not been able to adhere to even its tentative timetable with respect to such matters as this rulemaking or its pressure and size inquiry. Therefore, Alaska asks that the Commission give consideration to its schedule for implementing the incentive rate of return in light of the financing and construction timetables of the project," the state said.

IRS EXEMPTION FOR PIPELINE BONDING AUTHORITY FAILS TO PASS CONGRESS

Congress adjourned for the year without approving a change in Section 103 of the Internal Revenue Service Code, a change that would have been required for a state bonding authority approved last year to issue $1 billion in tax-exempt bonds for the gas pipeline.

The IRS code change apparently was blocked because Sen. Henry Jackson of Washington, chairman of the Senate Committee on Energy and Natural Resources, and other senators did not want anything to jeopardize a House vote on the natural gas pricing bill, part of President Carter's national energy package. The Treasury Department also opposed the change on grounds it would cause a loss in federal income.

There is some confusion and disagreement about the events surrounding consideration of this proposal.

According to Deming Cowles, an aide to Sen. Mike Gravel, the key reason the proposal failed to gain support was that Alaskan Northwest "didn't establish a record showing the need, desirability and benefit to consumers."

"It says conclusively in the President's Decision that the pipeline is supposed to be privately financed without any subsidy whatsoever, and yet here was Northwest asking for what some people consider a direct federal subsidy. People wanted to know whether the situation had changed. People wanted to see facts and figures," Cowles said.

"There was also negative reaction because the state was not issuing the bonds itself," he said. "People were asking, 'Why should federal taxpayers have to subsidize gas consumers, since not every federal taxpayer is a gas consumer?' There were some fairly sophisticated arguments against it, and Northwest simply didn't lay the groundwork."

The industrial development bond proposal was never formally considered by either house of Congress, although Gravel attempted to rally support at the last minute. Gravel first attempted to get the change included in the conference committee version of the energy tax bill, but it was rejected there because it was outside the scope of the conference.

Gravel circulated two different drafts of the proposal to key senators. The first would have limited the amount of bonds that could be issued to $3.2 billion and included funding for the North Slope conditioning facilities. The other placed no limit on the amount of bonds that could be issued. When it became clear the proposal would fail on the floor, Cowles said, Gravel decided not to pursue it.

Northwest lobbyist Bill Foster said the Gravel amendment was in fact introduced but never printed, although Cowles denies this. Foster said the increases in the amounts to be issued were Gravel's idea and were not requested by Northwest.

Northwest Alaskan officials told the legislative Interim Committee on Gas Pipeline Financing in September that they had postponed seeking the IRS change until Congress acted on the natural gas bill. Final congressional action on the natural gas bill, as well as the other parts of the President's energy package, did not come until the closing hours of the 95th Congress.

"It was the political judgment of Northwest not to proceed until the last minute. They came to us at the last minute and by then it was too late," Cowles said.

Cowles said Gravel, chairman of the Senate Finance Subcommittee on Energy and Foundations, probably will hold hearings on the proposed IRS change early in the next session of Congress.

PASSAGE OF NATURAL GAS BILL BOOSTS PIPELINE

Although the failure of Congress to pass the IRS code change might be considered a setback for the Alaska Highway gas pipeline, passage of the natural gas pricing bill is viewed by most as a major step forward.

The bill, which will gradually deregulate some new gas prices and extend regulatory controls to intrastate sales, provides 12 different prices for gas, depending on when and where a well was drilled and whether gas from that well has ever been sold interstate. Carter is expected to sign the entire energy package, including the natural gas pricing bill, in early November.

The bill is important to the Alaska Highway gas pipeline because it sets a ceiling price for North Slope gas and will allow the cost of expensive Alaska gas to be averaged with cheaper Lower 48 supplies, a device known as "rolled-in" pricing.

Specifically, the bill sets a Prudhoe Bay wellhead ceiling of $1.45 per million Btus as of April, 1977, plus an annual inflation factor (which with 6 percent annual inflation would make it roughly $2.25 per million Btus in 1984). This is a ceiling price, and it is uncertain whether the producers will be able to get the pipeline companies to pay that much. In addition to the value of the gas itself, the producers will be allowed to recover current state severance taxes (and future severance tax increases, provided they don't discriminate between interstate and intrastate sales) and their gathering and conditioning costs in the price they charge the pipeline companies.

The pipeline tariff and the wellhead ceiling will be passed on to consumers under the rolled-in mechanism. If the severance taxes and producer-borne gathering and conditioning costs push the price to the pipeline companies above the ceiling, FERC will decide whether the extra costs will be rolled-in or priced on an incremental basis to industrial and other low-priority users.

The bill specifies two categories of costs that will be priced under the incremental pass-through. State severance taxes enacted after December 1, 1977, and gathering and conditioning costs borne by parties other than the producers (presumably the pipeline companies or other gas purchasers) will be priced incrementally to industrial users.[1]

Of the rolled-in pricing provision, the joint conference report accompanying the legislation says: "The conferees agreed to provide rolled-in pricing for natural gas transported through the Alaska Natural Gas Transportation System and for the cost of transportation because they believed that private financing of the pipeline would not be available otherwise. Rolled-in pricing is the only Federal subsidy, of any type, direct or indirect, to be provided for the pipeline."

The fact that Congress allowed rolled-in pricing only for gathering and conditioning costs borne by the producers, and not for gathering and conditioning costs borne by other parties, seems to indicate its desire that the oil companies assume responsibility for financing and building the North Slope conditioning facilities, estimated to cost about $2 billion.

Passage of the natural gas pricing legislation clears the way for negotiations to begin between the producers and pipeline companies on gas sales contracts.

Northwest says it may be mid-1979 or later before these negotiations are completed and gas sales contracts are signed.

"In general, we would expect that final producer contracts cannot be obtained in less than 6 months following Congressional resolution of various pricing issues and perhaps not even then if the very important question of cost responsibility for processing Alaskan gas has not been settled by the FERC," Alaskan Northwest said in response to questions posed by Legislative Affairs on behalf of the interim committee studying a proposed $500 million equity investment by the state in the project.

The question of who should build and pay for the necessary conditioning facilities is one of the major issues that must be resolved before work can proceed on the Alaska Highway natural gas pipeline. These costs apparently will be borne either by the North Slope oil producers, or by the companies in the Alaskan Northwest pipeline consortium, or some combination of them.

It now appears the producers and pipeline companies will negotiate responsibility for the conditioning facilities at the same time they negotiate a sales price for the gas, but any agreement reached in

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[1] For a detailed discussion of the natural gas bill and its effects on Alaska, see "The Politics of Gas," by Steve Cowper, Alaska Advocate, October 19-25, 1978.

negotiations will be subject to FERC approval. It is possible, however, that FERC will hold a proceeding and settle the conditioning issue before the contract negotiations begin. Whatever procedure is followed, FERC will have to determine which costs are attributable to "production," which are the responsibility of the producers, and which to "transportation," which are the responsibility of the pipeline companies. If the conditioning plant were built by the pipeline companies, it would be regulated by FERC and its costs included in the pipeline tariff. If it were built by the producers, it would not be subject to FERC regulation.

Neither the producers nor the pipeline companies are eager to accept responsibility for the conditioning facilities. The producers have argued that if they must build the conditioning facilities, they might decide the investment at this time is not worth the gains to be made from gas sales. On the other hand, Northwest has argued that it may have difficulty raising enough money to pay for both the pipeline and the conditioning facilities.

FERC REPORT FAVORS 1260-psig PRESSURE FOR GAS PIPELINE

A report issued recently by the Alaska Gas Project Office of the Federal Energy Regulatory Commission favors a 1260-psig operating pressure for the northern sections of the Alaska Highway gas pipeline.

In preparing its report to FERC on the options for operating pressure, the Alaska Gas Project Office (AGPO) held discussions with the major interested parties, including the State of Alaska, Sohio, ARCO, Exxon and Alaskan Northwest Pipeline Company. The AGPO said its report does not represent an official FERC finding but is "an effort to illuminate the choice of maximum allowable operating pressure."

The Canadian National Energy Board (NEB) already has selected a 56-inch diameter, 1080-psig system for the sections of the pipeline south of Whitehorse, Yukon Territory. The Canadian decision, the AGPO said, had the effect of narrowing the options for the 48-inch segments north of Whitehorse to these: (1) the 1260-psig system proposed by Alaskan Northwest; (2) the 1680-psig system favored by two of the three principal North Slope gas producers (Exxon and ARCO); and (3) an intermediate design which would operate at 1440 psig.

Generally, the higher pressure systems can carry more Natural Gas Liquids (NGLs) than the lower pressure systems, and the higher pressures can move a greater volume of gas. The higher pressure systems cost more, but would be able to deliver gas cheaper (lower cost-of-service) at higher through-put levels than currently envisioned for the Alaska Highway project.

Alaskan Northwest told the AGPO it opposes the higher pressure alternatives. "A major source of concern is their belief that a delay of up to two years could result from choosing the higher pressure system due to a need for extensive testing of the various components of such a system," the report says. "A delay of up to two years is estimated by the project sponsors to result in additional carrying charges of up to $1 billion."

Alaskan Northwest showed a cost-of-service advantage for the lower pressure system at the through-put volumes they expect (between 2 and 2.4 billion cubic feet a day). The higher pressure alternative does not become superior in performance until the through-put rate passes 3.8 billion cubic feet a day, according to Alaskan Northwest's figures.

The AGPO said it believes that the President's Decision on the Alaska Natural Gas Transportation System "creates a predisposition that the 1260-psig system is the one authorized by the President and the Congress."

Before FERC should agree to a higher operating pressure than 1260-psig, the report says, it should get concurrence of the Canadian government, which has expressed "severe reservations" about the safety and reliability of the 1680-psig alternative.

FERC also should make sure that consumers would benefit from a decision to use a higher pressure system, the report says.

Finally, FERC should not select a higher pressure system if it would undermine the project sponsors' ability to secure private financing, the AGPO says.

Comments to FERC on the report are due November 15.

GAS CONDITIONING FACILITIES TO COST ABOUT $2 BILLION

Conditioning facilities necessary to prepare North Slope gas for pipeline shipment likely will cost about $2 billion, according to a voluminous study conducted for 11 pipeline companies and seven North Slope oil producers.

The seven-volume study, which has been in preparation since the summer of 1977, sets out a preliminary design for the conditioning facilities, a timetable for startup in the summer of 1983 (now acknowledged to be impossible to meet), implementation plans and cost estimates. The study was released to state officials in early October.

The study cost $1.4 million and was prepared for the 18 companies by the Ralph M. Parsons Company of Pasadena, Calif., an engineering construction firm. The companies conducting the study have kept some of the information proprietary, and they plan to sell it to the firms that ultimately build the conditioning facilities.

Conditioning the gas for shipment includes removing carbon dioxide and the heavier Natural Gas Liquids, and then compressing and chilling the gas to pipeline specifications.

The Parsons study makes a number of assumptions about the pipeline, including:

- Production of 2.6 to 2.8 billion cubic feet a day of raw gas, which would yield pipeline quality gas for shipment of 2 billion cubic feet a day (after field and local fuel gas demands and shrinkage from conditioning). The President's Decision anticipates pipeline through-put of 2.4 bcf/day.

- Pipeline pressure of 1440 psig. (The President's Decision anticipates pressure of 1260 psig.)

- Most of the Natural Gas Liquids will be shipped through the gas pipeline. Under the plan set out in the Parsons study, all of the ethane (C^2), all of the propane (C^3), and some of the butane (C^4) could physically be placed in the gas pipeline. The remainder of the butane and all of the pentane (C^5) would be shipped south in the Trans-Alaska oil pipeline.

If completed by 1983, the study says, the conditioning facilities would cost about $2 billion in escalated dollars (assuming inflation of 6.73 percent a year), with an accuracy of plus or minus 20 percent. Each year of delay would increase the cost about 9 percent, the study says.

DEPARTMENT OF NATURAL RESOURCES SELECTS FIRM TO PROMOTE PETROCHEMICALS

Bonner & Moore Associates, Inc., of Houston, Texas, has been awarded a $70,000 contract to help the state promote development of a petrochemical industry based on royalty gas and gas liquids.

Natural Resources Commissioner Robert LeResche said he intends to select a steering council of people from Fairbanks, Valdez, Haines, Anchorage, Kenai and perhaps other locations to assist Joe F. Moore, president of the consulting firm, and the Alaska Royalty Oil and Gas Development Advisory Board, in planning the development.

Once the steering council is established, LeResche said, "Joe Moore's job would be to put together the type of development that the council feels would be most beneficial, and to find a firm that would be willing to contract to buy the (royalty) gas and undertake the development. In this way we will be able to give potential purchasers a specific development that we want to see happen..."

Moore also will update a study he conducted last year for the Department of Revenue, which assessed the economic feasibility of gas-based petrochemical development in Alaska, transportation schemes, markets and other related issues. That study concluded that petrochemical manufacturing based on ethane and heavier NGLs is economical in Alaska at a wellhead gas price of about $1.24 per million Btus. However, that study was criticized by oil company representatives and others because it underestimated the costs of construction. LeResche said Moore's update study will use a more realistic "construction cost multiplier," which compares construction costs in Alaska with costs on the Texas Gulf Coast.

Before the state should enter into a contract selling the royalty gas, LeResche said, several factors outside the state's control need to be resolved. These include execution of gas sale contracts between the North Slope producers and the pipeline companies, and determinations by FERC on the size and pressure of the pipeline and specifics of the conditioning facilities (which will affect composition of the royalty gas).

CANADIAN DECISIONS ON GAS EXPORTS WILL AFFECT ALASKA HIGHWAY PIPELINE

Published reports[1] indicate that the outcome of Canadian National Energy Board gas supply-demand hearings, which began October 11, could affect the success of the Alaska Highway pipeline project.

Alberta gas producers are pushing the Canadian government to allow long-term gas exports to the United States, and they are pointing to substantial new gas discoveries in Canada's Deep Basin as justification.

"If the new reserves prove to be substantial, and if the Canadian government approves their long-term sale to the U. S., the gas could be transported much more cheaply by expanding existing pipelines than by building the costly new pipeline network to Alaska," Business Week reported recently.

The magazine quotes Canadian Hunter Exploration Ltd., the leading exploration company in the Deep Basin, as saying the area stretching from west-central Alberta north into British Columbia could contain 50 trillion cubic feet of natural gas, or nearly twice the proven reserves at Prudhoe Bay. Other estimates place the level of gas reserves at about 10 trillion cubic feet.

The Oil and Gas Journal said in its September 18 edition that "strong geological evidence points to the probable existence of an enormous gas accumulation trapped in the deepest part of the Alberta syncline and its extension into British Columbia... Reserve potential is so large as to alter significantly the energy supply estimates for North America."

The NEB must decide (subject to approval of the Canadian cabinet) whether to grant permission for increased gas exports into the United States. If it does give permission for massive, long-term sales (U. S. sales already account for more than 40 percent of Canadian gas sales), it will mark a dramatic turnaround in government energy export policy.

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[1] Business Week, Sept. 25, 1978; The Oil and Gas Journal, Sept. 18, 1978; The Financial Post (a Canadian publication), June 10, 1978; Energy User News, Oct. 2, 1978.

Since 1970, Canada has approved export licenses for only one year, provided the gas was surplus to Canadian requirements and the price was just and reasonable. The Alberta producers will be trying to convince the NEB that they have enough surplus gas to serve Canada as well as enough to export south for longer than one year.

The largest export applicant is PanAlberta Gas Co., Ltd., a subsidiary of Alberta Gas Trunk Line (AGTL). AGTL is part owner of Foothills Pipe Lines, which will build the Canadian sections of the Alaska Highway gas pipeline. PanAlberta already has signed tentative contracts with Northwest Alaskan Pipeline Company to export just over a billion cubic feet a day of gas for six years. Approval of this proposal would boost the entire Alaska Highway project, since such a vast amount of gas would require pre-building of the southern section of the pipeline. Pre-building has been promoted as a way to ease financing of the entire project.

A group of Alberta natural gas producers, called the "ProGas" consortium, has applied for government approval to export 500 million cubic feet a day to the Midwest through existing TransCanada pipelines for a five-year period. Approval of this rival proposal could be detrimental to the Alaska Highway pipeline, since it might preclude the need for the pre-built southern section.

BEAUFORT SEA SALE FACES OBSTACLES

A number of environmental, administrative, legal and economic problems make it uncertain whether the proposed Beaufort Sea offshore lease sale will take place in December of 1979 as planned.

This major offshore sale of more than half a million acres is being planned jointly by the state and the federal government, an unprecedented arrangement. It will be the state's first North Slope sale in more than a decade.

The Beaufort Sea is considered one of the most promising areas in the United States for finding new accumulations of oil and gas. Geologists estimate the offshore area may contain 2.7 billion barrels of recoverable oil and 13.5 trillion cubic feet of recoverable natural gas.

"The Beaufort Sea sale has more things going against it than for it right now," says Tom Cook, director of the Division of Minerals and Energy Management. "I expect to see a good deal of environmental opposition, and I'm sure there will be opposition from some quarters of the Native community. The objections they raised about the Point Thomson sale are a preview of what you'll see when the Beaufort is addressed in public forums."

Governor Hammond cancelled the Point Thomson North Slope sale in September, citing the federal government's failure to deal with the West Coast oil surplus, objections from local residents and the oil industry, lack of environmental data and a dispute with the Interior Department over title to the lands. The Point Thomson acreage is near two Exxon discoveries, and the state wanted to preclude "drainage" from under the unleased acreage. (It is unlikely this would occur in the near future, however, since Exxon has not announced plans for producing its discoveries.)

Environmental problems with the sale are likely to center on the bowhead whale, an endangered species, whose habitat and safety are protected under the federal Endangered Species Act of 1973. Very little research has been done on the bowhead's feeding, mating and migration patterns, so it is unclear whether the whales would be affected by development of the proposed sale area.

Protection of the bowhead is the responsibility of the National Marine Fisheries Service (NMFS) in the U. S. Department of Commerce, which can object to the sale if it determines there would be an adverse effect on the bowhead's safety or habitat.

Other environmental problems include professional disagreement over the safety and adequacy of available Arctic oil development technologies, particularly the industry's ability to prevent, contain and clean up oil spills.

The federal Bureau of Land Management's Outer Continental Shelf (OCS) office in Anchorage has contracted for two studies on the bowhead and environmental effects of the proposed sale, one to be conducted by the Alaska Whaling Commission and the other by the Naval Arctic Research Laboratory in Barrow. The results of these studies will be turned over to the NMFS, which will advise the Secretary of the Interior on whether a sale would be detrimental to the bowhead.

Bob Brock, assistant manager of the OCS office, said the secretary could decide to proceed with the sale whatever the NMFS decided, but "a jeopardy ruling (from NMFS) definitely would be a big obstacle."

Another category of obstacles involves the monumental task of reconciling and meshing different state and federal leasing laws and regulations.

The Beaufort Sea "Memorandum of Understanding" signed last March by Governor Hammond and Interior Secretary Andrus says the state and federal governments will develop compatible procedures for conducting the sale. This may involve, among many other things, adoption of a common lease form so that it will make no difference to bidders whether the land is owned by the state or federal government.

Of the offshore area proposed for sale, 68 percent belongs to the state, 13 percent belongs to the federal government, and 19 percent is disputed. Some staffers predict that the state and federal government eventually will end up in court over ownership of the disputed 19 percent.

The Department of Natural Resources currently is drafting new leasing procedures, a process that has been in motion since mid-1977. Most of the work was done, however, before passage of the new leasing law (HB 854) by the last legislature. Revised leasing procedures should be completed soon and may go to public hearings by the end of the year.

The procedures will formally establish an Alaska Advisory Committee on Leasing, composed of representatives of various state agencies and local governments, which will advise the commissioner of Natural Resources on proposed sales. This group has been operating on an ad hoc basis for about a year.

The new procedures also will mandate that a Social, Economic and Environmental Analysis (SEEA) be prepared by the state for each proposed sale. The Beaufort Sea SEEA is expected to be completed by March or April, and public hearings will follow.

Another potential problem is Public Land Order 82, an executive World War II action that reserved all submerged lands north of the Brooks Range crest for military purposes. The order was revoked in 1960, but Interior officials have argued that since it was in effect at the time of statehood, the state did not automatically get title to the lands.

The state is currently involved in what are described as "extremely delicate" negotiations with Interior on this issue. State officials believe the state's case on P.L.O. 82 is very strong, but they say they have refrained from discussing it publicly so as not to back Interior into a corner.

The ramifications of this issue for the state and the North Slope producers are staggering, since the land in question includes some of the state's greatest proven and potential resources, including about 40 percent of the oil and gas at Prudhoe Bay and the entire Arctic coastline out to the three-mile limit.

Another potential obstacle to the Beaufort Sea sale is resolution of the West Coast oil surplus. Some say it makes no sense for the state to proceed with additional leasing as long as the economic return on the resource is so low, and it is conceivable the state might cancel the sale if the federal government failed to take action to resolve the surplus.

STATE WILL SEEK PERMISSION TO EXPORT ROYALTY OIL TO JAPAN

Natural Resources Commissioner Robert LeResche says he will visit Japan in November to lay the groundwork for a short-term sale of the state's Prudhoe Bay royalty oil to a Japanese refiner.

The sale envisioned by LeResche would be structured as an exchange, with a refiner on the U. S. East Coast receiving an equivalent amount of foreign oil that would have gone to the Japanese refiner.

The state has been urging federal energy officials to allow the export or exchange of Alaska oil as a solution to the West Coast oil surplus. Since transportation costs would be lower if Alaska oil were moved directly to Japan instead of through the Panama Canal to the U. S. Gulf and East coasts, the wellhead price would be higher and the state's revenue from royalty and severance tax payments would increase.

The export of crude oil is now restricted by three federal laws with similar provisions. The most restrictive--1977 amendments to the Export Administration Act--allows exports of oil carried through a pipeline that crosses federal lands only if the President makes specific findings that the exports in question:

- will not diminish the total quantity or quality of crude oil available to the United States;

- will have a positive effect on consumer oil prices by decreasing the average crude oil acquisition costs for refiners;

- will be made only pursuant to contracts which may be terminated if the petroleum supplies of the United States are interrupted or seriously threatened;

- are in the national interest.

Either house of Congress could veto the proposed export.

The Japanese exchange under consideration by the state would be structured to meet those legal requirements. State officials view the royalty oil swap proposal as a way to lay the question directly on the desk of President Carter, who thus far has been reluctant to tangle with Congress, particularly the House of Representatives, on the issue.

If permission to exchange the royalty oil were granted by Carter and Congress, state officials believe it would be a "foot in the door" for the export of the producers' North Slope oil and would serve to diffuse political opposition to exports. When the question is considered in the national forum, the reasoning goes, it is advantageous to center debate on the least objectionable proposal possible: exchange of royalty oil (rather than producer oil) for non-Arab oil delivered to the U. S. East Coast.

LeResche's November trip also will take him to Mexico, which he says "looks like a real good potential third partner (to deliver oil to the U. S. East Coast) for the deal."

The legislature last session amended the state statute that requires legislative approval for the sale, exchange or disposition of royalty oil and gave the administration authority to make a one-year sale without legislative approval to relieve market conditions.

LeResche said he hopes to have the Japanese exchange worked out and ready for presentation to Carter early next year.

STATE CONSIDERS FOOTHILLS OIL PIPELINE PROPOSALS

Eight state departments are now analyzing proposals by a Canadian pipeline consortium to build a new oil pipeline from Skagway to existing pipelines in Alberta, or from Delta Junction down the Alaska Highway gas pipeline corridor. One commissioner is already on record opposing the proposals.

Foothills Oil Pipe Line Ltd., jointly owned by Alberta Gas Trunk Line and Westcoast Transmission, recently proposed the new oil pipelines as a way to move Alaska oil to inland U. S. markets. This is the same group of companies that will build the Canadian sections of the Alaska Highway gas pipeline.

The analysis, which is being coordinated by the Division of Policy Development and Planning, will examine economic feasibility, effect on state revenues, environmental impacts, impacts on communities, effect on the state's economy, and public sentiment toward the proposals, among other things. Responses from the participating departments--Revenue, Natural Resources, Environmental Conservation, Fish and Game, Transportation and Public Facilities, Community and Regional Affairs, Commerce and Economic Development, and Labor--are due November 17.

Foothills officials will be invited to respond in December to questions and problems identified by the departments. The state then hopes to take a formal position by the end of the year.

Revenue Commissioner Sterling Gallagher says he thinks the state should oppose the Foothills oil pipeline because its tariff will be too high to result in an $8 to $9 wellhead price. Gallagher says an $8 to $9 wellhead is needed before the oil companies will develop economically marginal North Slope fields such as Kuparuk and Lisburne.

"If we allow pipelines to be built that yield us only a $4 to $5 wellhead value, there will be economic pressure to keep that line full. We could keep those lines full for the next few years with Prudhoe Bay production, but in the long run, it would actually lower our return from the main Prudhoe Bay field and kill the incentive to develop smaller fields in Alaska," Gallagher said recently in a letter to the governor.

"I feel for the long-term development interest of Alaska, we should oppose all transportation alternatives which will not yield a sufficient incentive to obtain additional production from Prudhoe Bay, as well as other marginal fields in Alaska," Gallagher said.

In a presentation to state officials in September, Foothills officials asked for the state's opinion of the proposals and said they hoped to get a "consensus" before proceeding. Foothills has not yet filed a formal application with the Secretary of the Interior, although it will have to do so soon under terms of a new Crude Oil Transportation Systems law passed just before Congress adjourned. (See next item.)

Ed Phillips, senior vice president of Foothills Oil Pipe Line Ltd., said his firm will meet in November with representatives of Sohio and Ashland oil companies to see whether they will support the Foothills proposal.

"We have to have someone who says they'll put oil through our line" before we can move ahead, Phillips said. "If Sohio and Ashland turn us down, we'd have to do some fast scrambling. If they refused it would be a major setback."

Phillips said Foothills recently completed a reevaluation of the costs of building the Skagway-to-Whitehorse route, which showed a netback wellhead of about $3. "That's more than the state is getting now for the oil that is going to the Gulf Coast," he said. The Big Delta route would offer a higher netback to the state and also would be more attractive to environmentalists, he said. However, the Big Delta route would leave the southern portions of TAPS underutilized, and Sohio would have to pay the full TAPS tariff to Valdez, even if the oil were diverted to a new line near Fairbanks.

"If the state could indicate that there would be a significant increase in production from Prudhoe Bay," Phillips said, then the Big Delta route would be very attractive.

It is likely Foothills will have to make a decision on whether to proceed before the state completes its analysis, he said. "If we just get some encouragement from Sohio and Ashland, we'll be ready to go ahead."

CONGRESS APPROVES PROCEDURE FOR SELECTING WEST-TO-EAST OIL PIPELINES

Congress has established a procedure for Presidential selection of west-to-east crude oil pipelines in an attempt to solve both the West Coast surplus and a "serious shortage" of oil in the northern tier states.

The new "Crude Oil Transportation Systems" law is part of the Public Utility Regulatory Policies Act, one section of President Carter's energy package.

Declaring that "expeditious Federal and State decisions for west-to-east crude oil delivery systems are of the utmost priority," Congress set up a procedure for review of pipeline alternatives by federal agencies, which will make recommendations to the President.

In order to be eligible for consideration, applications for proposed pipelines must be filed with the Secretary of the Interior within 30 days after the bill is signed by the President. The secretary may accept proposals for an additional 60 days if he determines they are in the national interest.

The bill states that final Environmental Impact Statements on accepted applications must be completed by December 1, 1978. The President will have 45 days (subject to a 60-day extension, if necessary) after receiving comments and recommendations to decide which, if any, of the proposed pipelines will be approved.

Once a pipeline is selected, the new law provides an expedited procedure for action on all federal permits, licenses and approvals required for construction and operation of the system. The law also mandates expedited federal authorizations on the proposed Sohio pipeline from Long Beach to Midland, Texas, although all federal authorizations for this project already have been granted.

The Sohio pipeline, however, still must get air quality permits from the California South Coast Air Quality Management District Board, a process that could take another year. The board has not yet approved Sohio's plan to offset the air pollution from its project by installing a $78 million scrubber on a Southern California Edison power plant.

In addition, city of Long Beach voters will decide November 7 whether land owned by the city should be leased to Sohio for the project's terminal. A rejection by Long Beach voters would delay the project at least a year, when the issue could be placed on the ballot again. Sohio lobbyist Ken Showalter said the company might consider moving the port terminal to Los Angeles harbor in the event the Long Beach referendum fails.

A number of other proposed west-to-east pipelines have been under consideration for years but have faced numerous environmental and regulatory obstacles.

The Kitimat pipeline project, which would require new construction from a terminal at Kitimat, British Columbia, to Edmonton, Alberta, and use existing pipelines from Edmonton into the Midwest, was essentially killed when the Canadian National Energy Board decided recently that the country does not need oil importing facilities on its west coast.

Reversal of the existing Trans-Mountain pipeline between Cherry Point, Washington, and Edmonton was precluded by an amendment to federal law that prohibits expansion or building of any new oil docks east of Port Angeles, Washington.

The Northern Tier pipeline project, which would run a new pipeline from Port Angeles to Clearbrook, Minnesota, recently got approval from Washington State after a long series of regulatory hearings. However, Clallam County, which would be host for the oil port, has challenged in court the state's right to preempt local land-use ordinances. If the court were to rule against the state, it could kill the project by precluding construction of a tank farm in Clallam County, according to Associated Press reports.

Passage of the "Crude Oil Transportation Systems" law is an expression of Congress' desire to bring about construction of a west-to-east pipeline to serve the crude-short northern tier states of Washington, Oregon, Idaho, Montana, North Dakota, Minnesota, Michigan, Wisconsin, Illinois, Indiana and Ohio. These states used to depend heavily on oil imported from Canada, which averaged about 1.2 million barrels a day in 1973.

The Arab oil embargo brought a drastic change in Canadian export policy, and the government had planned to phase out oil exports completely by the early 1980s in order to conserve oil for its own use. Canada now exports about 180,000 barrels a day to the northern tier states, and originally had planned to cut exports by 20,000 barrels a day in 1979 and down to 1,000 barrels a day in 1980.

However, because of a lower-than-expected demand and a brighter supply picture, the NEB recently decided that light oil exports (now 55,000 barrels a day) would be continued at the current level for three years and cease in 1981 except in exchange arrangements. Exports of heavy oil will be allowed to continue without restriction, as is current policy, as long as Canadian requirements are met first.

PETROLEUM REVENUES FALL BELOW PRE-PRODUCTION EXPECTATIONS

The West Coast oil surplus and higher-than-expected pipeline tariffs and tanker transportation charges have substantially reduced the state's petroleum revenues from levels predicted a year and a half ago.

The declining trend of estimates for the current fiscal year are shown below.

Estimates of FY 79
Petroleum Royalty and Severance Tax Revenues
(millions of dollars)

	Royalties*	Severance Tax	Total
LAA-Research Forecast			
March 1977			657.1
May 1977			634.0
Dept. of Revenue Forecast			
June 1977	520.9	207.7	727.1
January 1978	358.0	176.0	534.0
LAA-Research Forecast			
June 1978			437.4
Dept. of Revenue Forecast			
September 1978	273.2	160.5	433.7

* Royalty amounts are gross figures without deductions for permanent fund contributions (25%), renewable resources fund contributions (5%) or native claim settlement payments (16% of royalty; or 2% of total gross value). Not included in these figures are oil and gas property tax or income tax revenues.

The 1977 estimates made prior to actual production were based on the expectation that wellhead values would be about $7.50. In fact, the wellhead price has never been this high; it has ranged from a high of $6.23 in August of 1977 to a low of $4.23 in May of 1978. The average wellhead price currently is about $4.40.[1]

Deputy Revenue Commissioner John Messenger says a $7.50 wellhead was not an unreasonable expectation, since "the oil companies themselves, as well as numerous other third party experts, were projecting wellhead values in the $7 to $8 range" in early 1977.

Declining oil revenues can be attributed to four major factors:

Pipeline tariffs -- In June 1977 the eight oil companies that own TAPS filed initial tariffs with the Interstate Commerce Commission (now FERC) ranging from $6.04 per barrel to $6.44 per barrel. The average was about $6.20 per barrel. The State of Alaska, the U. S. Department of Justice, the ICC's Bureau of Investigations and Enforcement and the Arctic Slope Regional Corporation filed objections, claiming the tariffs were too high.

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[1] The table attached as an appendix to this report, which was prepared by Al Latham, shows a month-by-month breakdown of Prudhoe Bay oil destinations and prices.

After considering the protests, the ICC decided the high initial tariffs were not in the public interest and ordered them suspended. The ICC instituted "interim" tariffs averaging about $4.84 per barrel, which were to be in force for seven months while it considered various substantive issues.

Several of the oil companies then brought suit against the ICC, claiming it had no authority to deny the carrier's initial filings. The U. S. Supreme Court allowed the owner companies to reinstate their initial tariffs for a period, but on June 6, 1978, the high court upheld FERC's authority to suspend the initial tariffs and set interim tariffs instead. The state got a retroactive payment of about $17 million for royalty and severance taxes as a result of this decision. However, since the commission's "interim" tariff order was only in effect for a seven-month period, which expired February 28, 1978, the average company tariff of about $6.20 has been in effect for some time and will remain in effect until FERC rules on the tariff case.

The issue is being considered in two phases. Phase I involves general issues of methodology, such as the proper method of calculating the rate of return. A FERC administrative law judge will continue to take testimony on Phase I until late January. Thirty-seven rebuttal witnesses for the oil companies will begin testifying the first week in November.

The judge is expected to make a decision, or perhaps a recommendation to FERC, sometime next spring. If the judge decides the case, his decision could be appealed to the full commission. Whatever procedure is used, the losing side can (and probably will) appeal FERC's decision to the federal courts. Attorneys for the state say they expect FERC to make its decision on Phase I by June, 1979.

If the state gets a favorable ruling on Phase I, the tariff could be reduced by several dollars, state attorneys say.

The main issue in Phase II involves the costs of constructing the pipeline. FERC will determine which costs were reasonable and prudent and should be included in the rate base, and which were not reasonable and should be excluded. Hearings on Phase II probably won't begin before next summer, and it is likely to be several years before the tariff issue is finally resolved.

Field charges -- State royalty payments (one-eighth of production) are based on the wellhead value of the oil. The state claims these payments should be based on the value of the oil as it enters the Trans-Alaska pipeline. The oil companies claim the royalty payments should be based on the value of the oil as it comes out of the ground, and that the state should pay some or all of the "field charges" or "upstream costs." These charges range from 52¢ to $1.11 per barrel, depending on the company, and currently are being deducted from the state's royalty payments.

In October, 1977, the state filed suit against the companies, claiming that royalty payments were being calculated incorrectly. The issue is being litigated in two stages. The first question to be settled is whether the oil companies can properly deduct field charges from the royalty payments.

Oral arguments on the first part of the case were delayed because state Superior Court Judge Allen Compton suffered a heart attack in August. Compton recently returned to the bench on a part-time basis, and oral arguments are now scheduled for December 11.

Tanker transportation costs -- In computing the wellhead value of the oil, the companies take the destination sales price and then subtract the pipeline tariff, the field charges and the tanker charges for moving the oil from Valdez to the West and Gulf coasts.

The companies have been claiming tanker transportation costs ranging from 81¢ to $1.08 to the West Coast and from $2.75 to $3.64 to the East and Gulf coasts. Before production began, the oil companies and other third party experts projected tanker costs to the West Coast of 50¢ to 70¢ and charges to the Gulf Coast of $2.50 to $2.70.

Whether the tanker charges being claimed by the companies are too high will be litigated in the second part of the royalty suit.

Martingale, Inc., of Cambridge, Massachusetts, currently is conducting a study of tanker transportation charges under a $68,400 contract with the Legislative Affairs Agency and the Department of Revenue. The study is scheduled for completion in December.

West Coast oil surplus -- Because all Prudhoe Bay production cannot be consumed on the West Coast, and cannot be exported, the surplus oil must be shipped at a much higher cost through the Panama Canal to the U. S. Gulf and East coasts. In August, the latest month for which figures are available, 431,000 barrels a day, or 36 percent of total Prudhoe Bay production, went to the Gulf and East coasts.[1]

The extra charges for shipping this oil the longer distance to market directly reduce the wellhead price.

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[1] Energy Background Report #1, September 28, 1978, incorrectly stated that about 600,000 barrels a day are shipped through the Panama Canal. This figure was supplied by Revenue Commissioner Sterling Gallagher, but subsequent calculations by the Legislative Affairs Research Division indicate that the 431,000 figure is correct.

ALPETCO CONTINUES SEARCH FOR PETROCHEMICAL FACILITY SITE[1]

ALPETCO has narrowed possible sites for its contemplated world scale refinery-petrochemical complex from four to two--Valdez and Kenai (Wildwood)--and anticipates making its final choice known by mid-November.

A Cook Inlet Regional Native Corporation spokesman indicated that ALPETCO is negotiating with the Kenai Native Association to lease the Wildwood site. However, ALPETCO denies that the firm has made a final selection.

ALPETCO is proceeding with the preparation of a Draft Environmental Impact Statement (DEIS). It details the scope of work to be performed by ALPETCO to meet Environmental Protection Agency (EPA) requirements. The scope of work for the DEIS is expected to be adopted before the end of the year after review by the EPA, the Department of Environmental Conservation, other federal and state agencies, and the public.

ALPETCO has continued to meet with representatives of Japanese firms to discuss participation in the project. ALPETCO believes it will be able to obtain satisfactory agreements with refiners and marketers to sell "light ends" of the crude on the West Coast. However, ALPETCO is experiencing difficulty in finding a market for the "heavy ends" produced from Alaska crude. The firm is presently working to develop alternative solutions to this problem.

Additionally, the results of soils investigations conducted previously at the various sites by ALPETCO are now being used to analyze the relative merits of the two remaining sites. ALPETCO has filed a National Pollutant Discharge Elimination System (NPDES) Application for Permit to Discharge Waste Water with the EPA. The company has installed air quality monitoring stations at the Kenai and Valdez sites. Monitoring is being performed by Dames and Moore.

ALPETCO has hired a vice president for operations, Michael B. Carmichael, who formerly worked for Mobil Oil and Exxon. He will be in charge of design and construction, as well as operation of the project.

STATE APPEALS TANKER LAW DECISION

The state has asked the Ninth U. S. Circuit Court of Appeals to overturn a lower court decision that invalidated major portions of the state tanker regulation law enacted in 1976.

U. S. District Judge James M. Fitzgerald, drawing on a recent U. S. Supreme Court decision, ruled June 30 that the federal government has exclusive jurisdiction in regulating tanker equipment and design features

[1]Contributed by Elke Kallab.

under the Ports and Waterways Safety Act of 1972. Therefore, Alaska cannot charge oil tankers "risk avoidance" fees based on state-imposed design and construction standards, the judge ruled.

The judge also ruled that the Coastal Protection Fund is a dedicated fund, which is prohibited by the Alaska Constitution.

Fitzgerald said his decision had nothing to do with whether Alaska may or should have a Coastal Protection Fund providing a ready source of money to clean up oil spills and abate pollution, since other states have created funds for that purpose which have been upheld. The only question, the judge said, is "whether the means chosen by the state to accomplish its purposes are in accord with federal and state constitutional provisions."

The suit, filed by North Slope and Cook Inlet oil producers (Chevron, ARCO, Exxon, Mobil, Union Oil of California) and companies operating tanker fleets in the Alaska trade (Gulf Oil, International Ocean Transport, Keystone Shipping), sought to declare the Alaska tanker law unconstitutional and prevent its enforcement.

The Alaska law regulates tanker vessel traffic, transfer of crude oil and refined petroleum products, oil terminal facilities and marine carriers, through a licensing system of risk avoidance certificates. Its stated purpose is to decrease the likelihood of oil spills in Alaska waters by requiring tankers carrying oil to be equipped with certain safety and maneuvering capability features, and, if they don't have these features, to be escorted by tugs while navigating in the coastal waters of the state.

To navigate in state waters, tankers must acquire certificates of risk avoidance, which are conditioned on proof of financial responsibility and payment of an annual risk charge. The risk charges (along with other damages, penalties and fees) go into the Coastal Protection Fund. The amount of the risk charge depends on the presence or absence of safety equipment and design features.

The U. S. Supreme Court last March ruled unconstitutional part of a Washington state tanker law requiring certain design features on tankers entering Puget Sound (Ray V. ARCO). The high court held that Congress had entrusted the Coast Guard with the duty of determining which tankers are sufficiently safe, and that states are foreclosed from imposing different or more stringent design and construction regulations.

Other issues in the Alaska suit are scheduled for trial in December. These include whether the state can prohibit ballast discharge into state waters, whether the state can board tankers for inspection without a warrant, whether the state can require operating certificates, and whether the state can revoke operating certificates without due process.

OPEC MAY RAISE OIL PRICES

The Organization of Petroleum Exporting Countries (OPEC) is expected to hike the price of oil by 5 to 15 percent at its meeting in Abu Dhabi in December, press reports indicate.

Former Saudi Arabian oil minister Sheikh Abdullah Turaiki has been quoted as saying the increase might be as high as 30 percent, but most consider this unlikely.

Kuwait's Sheik Ali Khalifah, currently OPEC's president, has said he will recommend a 10 percent increase, while Saudi Arabia, the cartel's largest producer, has suggested that a 5 percent increase would be reasonable.

Oil prices have not been rising as rapidly as inflation, and have not been raised substantially since the four-fold increase in early 1974.

An increase in OPEC prices would mean higher prices for Alaska oil, since under the federal government's complicated pricing and entitlements structure, Alaska oil receives the imported price.

CONGRESS APPROVES STOCK OWNERSHIP PLAN

Congress has approved, and President Carter says he will sign into law, a far-reaching change in the tax law that allows states to establish private corporations for the benefit of their citizens.

The new law, pushed through Congress by Alaska Senator Mike Gravel, authorizes formation by states of General Stock Ownership Corporations (GSOC). The plan has been hailed by its sponsors as a grand experiment in economic democracy, a way to distribute the state's resource wealth to all citizens.

The GSOC, if it meets certain statutory requirements, will not be subject to federal income tax. Instead, shareholders of the GSOC will be taxed on their daily pro rata shares of the GSOC's taxable income.

All residents of a state which charters a GSOC are eligible to become shareholders in the corporation and are entitled to a stock interest in the corporation (provided they are residents at the time of chartering and remain residents until stock is issued). At least 90 percent of the income of the GSOC which is not used to pay corporate operating expenses must be distributed to the shareholders each year.

Shareholders would not be able to sell their GSOC stock for five years after acquiring it, and no one individual could purchase or otherwise acquire more than 10 shares of GSOC stock.

Gravel has suggested that the Alaska GSOC purchase British Petroleum's 15.8 percent share of the Trans-Alaska oil pipeline as its first investment. Other investment possibilities include the gas pipeline and the Alpetco petrochemical-refinery facility, or any other business venture.

The GSOC could get money for investment from private lenders, such as commercial banks, or from grants of money, land or mineral rights from the state. The new law would not permit the use of tax-exempt financing for state loans to the GSOC, but the state presumably could loan money to the GSOC at a subsidized interest rate.

Earnings from the venture would pay off the loans, and the leftover profits would be distributed as dividends to the citizen stockholders.

Gravel, who derived the idea from the economic philosophy of Louis Kelso, predicts the Alaska venture will alter American politics and economics in profound ways, as other states rush to copy the yet-to-be-developed Alaska model. Gravel says the GSOC is an alternative to welfare-state socialism, a way to distribute benefits of corporate capitalism without nationalizing private enterprises and turning over their management to politicians and bureaucrats.

Appendix
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PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
July 1977	ARCO	1,400,000	13.44	W.C.	.88	4.91	.74	6.91	
	EXXON	1,400,000	13.16	W.C.	1.12	5.10	.53	6.41	
	SOHIO	1,900,000	13.37	W.C.	1.10	4.74	.66	6.87	
		200,000	12.53	Valdez	-	4.75	.66	7.12	
		1,600,000	13.42	E & GC	3.83	4.76	.66	4.17	
		23% of total production or 52,000 bbl/day to East and Gulf Coast						5.94 av.	
August 1977	ARCO	3,100,000	13.44	W.C.	.88	4.91	.74	6.91	5% increase in average wellhead price.
	EXXON	3,000,000	13.16	W.C.	1.11	5.10	.53	6.42	a. Attributable to an 18-fold increase in Alaskan sales.
		74,000	12.30	Valdez	-	5.10	.53	6.67	
	SOHIO	900,000	13.37	W.C.	1.10	4.74	.66	6.87	
		3,800,000	12.53	Valdez	-	4.75	.66	7.12	
		3,400,000	13.42	E & GC	3.83	4.76	.66	4.17	
		23% of total production or 113,000 bbl/day to East & Gulf Coast						6.23 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
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20 October 1978

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Sept. 1977	ARCO	4,300,000	13.44	W.C.	.88	4.91	.74	6.91	1% decrease over previous month in average wellhead price. a. Attributable to a 98% decrease in Alaskan sales and a 1% increase in East and Gulf Coast sales.
	EXXON	4,200,000	13.16	W.C.	1.15	5.10	.53	6.38	
		87,000	12.3[illegible]	Valdez	-	5.10	.53	6.67	
	SOHIO	4,200,000	13.37	W.C.	1.11	4.75	.66	6.85	
		2,200,000	12.50	W.C.	-	4.77	.66	7.07	
		5,000,000	13.44	E & GC	3.83	4.75	.66	4.20	
		24% of total production or 165,000 bbl/day to East and Gulf Coast						6.17 av.	
Oct. 1977	ARCO	4,400,000	13.44	W.C.	.88	4.91 6.04	.76	6.46	8% decrease over previous month in average wellhead price. a. Attributable to an approximately 25% increase in pipeline tariff at mid-month. b. Exacerbated by a 39% decrease in Alaskan sales.
	EXXON	4,200,000	13.16	W.C.	1.08	6.06	.53	5.49	
		200,000	12.30	Valdez	-	5.53	.53	6.24	
	SOHIO	5,400,000	13.30	W.C.	.92	5.22	.66	6.50	
		1,200,000	12.52	Valdez	-	5.70	.66	6.16	
		5,100,000	13.42	E & GC	3.32	5.36	.66	4.08	
		23% of total production or 166,000 bbl/day to East & Gulf Coast						5.69 av.	

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July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Nov. 1977	ARCO	4,300,000	13.44	W.C.	.88	6.04	.76	5.76	13% decrease over previous month in average wellhead price.
	EXXON	4,300,000	13.16	W.C.	1.08	6.27	.53	5.28	a. Attributable to full effect of 25% increase in pipeline tariff.
		45,000	12.30	Valdez	-	6.27	.53	5.50	b. Exacerbated by an 11% decrease in Alaskan sales.
	SOHIO	5,000,000	13.30	W.C.	.92	6.26	.66	5.46	
		1,200,000	12.50	Valdez	-	6.26	.66	5.58	
		5,100,000	13.40	E & GC	3.31	6.25	.66	3.18	
		24% of total production or 168,000 bbl/day to East & Gulf Coast						4.94 av.	
Dec. 1977	ARCO	4,500,000	13.44	W.C.	.88	6.04	.76	5.76	2% decrease over previous month in average wellhead price.
	EXXON	3,900,000	13.16	W.C.	1.08	6.27	.53	5.28	a. Attributable to a 3% increase in East and Gulf Coast sales.
		500,000	12.30	Valdez	-	6.27	.67	5.36	b. Moderated by a 40% increase in Alaskan sales.
		42,000	12.30	Valdez	-	6.27	.53	5.50	
	SOHIO	4,600,000	13.30	W.C.	.92	6.30	.66	5.42	
		1,200,000	12.53	Valdez	-	6.28	.66	5.59	
		6,100,000	13.41	E & GC	3.32	6.31	.66	3.12	
		27% of total production or 199,000 bbl/day to East & Gulf Coast						4.85 av.	

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July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Jan. 1978	ARCO	4,600,000	13.44	W.C.	.88	6.04	.76	5.76	0.3% decrease over previous month in average wellhead price. a. Attributable to a 4% increase in East & Gulf Coast sales, but almost totally counterbalanced by a 26% increase in Alaskan sales.
	EXXON	3,600,000	13.16	W.C.	1.11	6.27	.53	5.25	
		500,000	13.33	W.C.	1.30	6.27	.53	5.23	
		500,000	12.30	Valdez	-	6.27	.53	5.50	
	SOHIO	3,200,000	13.33	W.C.	.99	6.27	.66	5.41	
		1,700,000	12.50	Valdez	-	6.26	.66	5.58	
		7,100,000	13.41	E & GC	3.05	6.27	.66	3.43	
		31% of total production or 234,000 bbl/day to East & Gulf Coast						4.84 av.	
Feb. 1978	ARCO	4,100,000	13.44	W.C.	.88	6.04	.76	5.76	5.2% decrease over previous month in average wellhead price. a. Attributable to an 11% increase in East & Gulf sales. b. Exacerbated by an 18% decrease in Alaskan sales.
	EXXON	3,600,000	13.16	W.C.	1.13	6.27	.53	5.23	
		500,000	5.98	PS 1	-	-	.53	5.45	
	SOHIO	1,000,000	13.36	W.C.	.99	6.27	.66	5.44	
		1,300,000	12.50	Valdez	-	6.26	.66	5.58	
		8,300,000	13.28	E & GC	3.05	6.27	.66	3.30	
		42% of total production or 273,000 bbl/day to East & Gulf Coast						4.59 av.	

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20 October 1978

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
March 1978	ARCO	6,300,000	13.44	W.C.	.88	6.04	.76	5.76	2.6% decrease over previous month in average wellhead price. a. Attributable to apparent sale price discounting on West Coast and in Alaska by Sohio. b. Moderated by 1% decrease in East & Gulf Coast sales and 35% increase in Alaskan sales.
	EXXON	5,600,000	13.16	W.C.	.94	6.27	.71	5.24	
		430,000	5.98	PS 1	-	-	.53	5.45	
		270,000	13.00	E & GC	3.29	6.27	.64	2.80	
	SOHIO	3,000,000	13.12	W.C.	.99	6.27	.66	5.20	
		2,000,000	12.11	Valdez	-	6.29	.66	5.16	
		11,900,000	13.05	E & GC	3.05	6.27	.66	3.07	
		41% of total production or 399,000 bbl/day to East & Gulf Coast						4.47 av.	
April 1978	ARCO	7,000,000	13.44	W.C.	.88	6.04	.76	5.76	2% decrease over previous month in average wellhead price. a. Attributable to apparent 3%-5% discounting of W.C. sales price by Exxon and Sohio. b. Exacerbated by a 38% decrease in Alaskan sales. c. Moderated by a 1% decrease in East & Gulf Coast sales.
	EXXON	5,200,000	12.83	W.C.	.93	6.27	.72	4.91	
		500,000	5.98	PS 1	-	-	.53	5.45	
		1,300,000	13.00	E & GC	3.33	6.27	.68	2.72	
	SOHIO	5,800,000	12.40	W.C.	.86	6.27	.66	4.61	
		1,000,000	12.50	Valdez	-	6.25	.66	5.59	
		11,500,000	13.01	E & GC	2.78	6.27	.66	3.30	
		40% of total production or 441,000 bbl/day to East & Gulf Coast						4.39 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
May 1978	ARCO	7,100,000	13.44	W.C.	.88	6.04	.76	5.76	3.6% decrease over previous month in average wellhead price. a. Attributable to 4% increase in East and Gulf Coast sales and continued apparent sales price discounting on West Coast by Exxon and Sohio. b. Moderated by 7% increase in Alaskan sales and new sales in Hawaii.
	EXXON	5,300,000	12.65	W.C.	1.09	6.27	.53	4.76	
		500,000	5.98	PS 1	-	-	.53	5.45	
		600,000	12.81	Hawaii	1.32	6.27	.53	4.69	
		700,000	13.00	E & GC	3.64	6.27	.53		
	SOHIO	3,200,000	12.64	W.C.	.86	6.27	.66	4.85	
		1,100,000	11.80	Valdez	-	6.26	.66	4.88	
		14,500,000	13.05	E & GC	3.02	6.27	.66	3.10	
		44% of total production or 512,000 bbl/day to East & Gulf Coast						4.23 av.	
June 1978	ARCO	7,100,000	13.44	W.C.	.88	6.04	.76	5.76	3.5% increase over previous month in average wellhead price. a. Attributable to 4% decrease in East & Gulf Coast sales. b. Moderated by continuing West Coast and Alaskan discounting and a 13% decrease in Alaskan sales
	EXXON	4,900,000	12.65	W.C.	1.11	6.27	.53	4.74	
		1,100,000	13.18	G.C.	3.35	6.27	.53	3.03	
		700,000	13.41	E.C.	3.64	6.27	.53	2.97	
		400,000	5.54	PS 1	-	-	.53	5.01	
	SOHIO	5,400,000	12.67	W.C.	.86	6.27	.66	4.88	
		1,000,000	11.79	Valdez	-	6.27	.66	4.86	
		12,100,000	13.10	E & GC	2.87	6.27	.66	3.30	
		40% of total production or 465,000 bbl/day to East & Gulf Coast						4.38 av.	

W.C. = West Coast
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PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
July 1978	ARCO	7,300,000	13.41	W.C.	.88	6.04	.76	5.73	4% increase over previous month in average wellhead price. a. Attributable to a 7% decrease in East & Gulf sales plus an Hawaiian sale and an 18% increase in Alaskan sales. b. Moderated by continued discounting of Alaskan and West Coast sales price by Exxon & Sohio.
	EXXON	350,000	5.54	PS 1	-	-	.53	5.01	
		6,200,000	12.65	W.C.	1.09	6.27	.53	4.76	
		570,000	12.81	Hawaii	1.31	6.27	.53	4.70	
		110,000	13.18	E & GC	2.93	6.27	.53	3.45	
	SOHIO	6,200,000	12.66	W.C.	.79	6.27	.66	4.94	
		1,300,000	11.80	Valdez	-	6.25	.66	4.89	
		11,600,000	13.09	E & GC	2.77	6.27	.66	3.39	
		33% of total production or 385,479 bbl/day to East & Gulf Coast						4.56 av.	
Aug. 1978	ARCO	7,400,000	13.41	W.C.	.88	6.04	.76	5.73	3% decrease over previous month in average wellhead price. a. Attributable to a 3% increase in East & Gulf Coast sales and continued discounting of Alaskan and West Coast sales price by Exxon & Sohio.
	EXXON	7,000,000	12.65	W.C.	.93	6.27	.70	4.75	
		210,000	5.54	PS 1	-	-	.53	5.01	
		220,000	13.18	E & GC	2.75	6.27	.70	3.46	
	SOHIO	5,500,000	12.68	W.C.	.79	6.27	.66	4.96	
		1,050,000	11.80	Valdez	-	6.25	.66	4.89	
		12,900,000	13.14	E & GC	3.03	6.27	.66	3.18	
		36% of total production or 431,000 bbl/day to East and Gulf Coast						4.44 av.	

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20 October 1978

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

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

M E M O R A N D U M

September 28, 1978

SUBJECT: Legislators' Energy Background Report

TO: All Legislators

FROM: Gregg K. Erickson
Director of Research

Over the past year, the Research Division has received an increasingly large number of requests from legislators for background material on various Alaska energy issues. The attached background report represents an effort to meet this need in a more regular and formal way. Compiling a report takes a good deal of staff time, and we're not certain this is the most efficient way to get the information you need to you in a timely manner. Your comments will be very important in determining whether the effort is continued. In the next report, we will enclose a self-addressed, stamped envelope and a questionnaire, which we hope you will use to let us know your reactions.

This report is generally the work of Kay Brown, although we expect that other staff members will also contribute from time to time.

GKE:jm
Attachment

UNRESOLVED ISSUES

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

ENERGY BACKGROUND REPORT FOR LEGISLATORS

September 26, 1978

NATURAL GAS PRICING LEGISLATION DELAYS PIPELINE PROJECT

The failure of Congress to enact President Carter's energy package has virtually halted progress toward securing financing for the Alaska Highway natural gas pipeline.

John G. McMillian, chairman of Northwest Alaskan Pipeline Company of Salt Lake City, says the pipeline already has slipped nearly a year behind schedule due to Congressional inaction and won't be completed until the winter of 1983-84, at the earliest.

Reports from Washington indicate the Senate will vote September 27 on the conference committee version of the controversial natural gas bill, and House consideration is expected in early October.

Most of the controversy has centered on provisions unrelated to the Alaska Highway gas pipeline, primarily whether to deregulate new gas prices in the now-regulated interstate market, or regulate prices in the now-unregulated intrastate market. The conference committee bill that reconciles vastly different House and Senate versions pleased practically no one and prompted a coalition of pro-consumer and pro-industry senators to team up against it. In light of a recent vote in the Senate that failed to send the natural gas bill back to conference committee, however, many observers predict passage.

When and if the bill is approved by Congress, it will provide a boost to the pipeline sponsors, who have been frustrated by months of delay and inaction. Work on the project cannot proceed until a price is established for the gas, and defeat of the legislation likely would mean an extended pricing proceeding before the Federal Energy Regulatory Commission (FERC).

The bill would establish a ceiling wellhead price of $1.45 per thousand cubic feet for Prudhoe Bay gas (as of April, 1977), with price escalators for inflation. The legislation would permit "rolled-in" pricing of both wellhead and transportation costs, a provision considered essential for the marketability of the gas. (Rolled-in pricing means the pipeline companies buying high-cost Alaska gas can average its cost with other, cheaper gas sources when billing consumers. Incremental pricing, in contrast, means consumers pay for Alaska gas separately--and its costs, therefore, stand out sharply compared to other gas supplies.)

The legislation does not determine who will bear the costs of gathering and conditioning the gas, leaving this point to be settled in negotiations between the North Slope producers and pipeline companies. (Any agreement reached on this point is subject to FERC approval.) The legislation does provide, however, that some of the gathering and conditioning costs may be passed through on an incremental basis to industrial and other low priority customers, thus raising the price to these consumers. While no one at present seems to understand how this complex pricing mechanism will work, FERC must figure out how to administer it and make the ultimate determination on which costs will be rolled-in and which priced incrementally.

CONDITIONING COSTS ?

Even with immediate action on the gas pricing bill, the Northwest project still faces a long series of hurdles before construction can begin.

It is not yet clear whether Northwest and its five partners, which are seeking to borrow massive amounts of cash, relative to their size, will be able to convince some combination of the State of Alaska, the North Slope producers and private lenders to finance the mammoth project, now estimated to cost at least $12 billion ($4.5 billion for the Alaska section alone). Nor is it clear whether the North Slope producers will be willing to produce and sell their gas, particularly if the price they are able to negotiate with the pipeline companies falls below the ceiling permitted by law. Northwest hopes to begin negotiations with the North Slope producers shortly after a ceiling price for the gas is established. These negotiations likely will address three major issues: 1) Who will pay how much for the North Slope conditioning plant necessary to prepare the gas for shipment? 2) To what extent, if any, will the producers participate in financing the pipeline? and 3) How much will the pipeline companies pay the producers for the gas?

Some observers believe it will not be possible to pay for the project with purely private financing (even with support from the State of Alaska) and that federal assistance ultimately will be required.

Besides the price and the producer sales contracts, a number of other factors also have to be resolved before Northwest can begin serious discussions with private lenders. Some of these factors are:

- A final resolution by FERC on the "variable rate-of-return," which will determine the amount pipeline companies and other equity owners can earn on their invested money. FERC now awaits public and industry comment on a revised proposal, but it is uncertain when a final decision will be made.

- Approval by FERC of the tariff structure. A proposed tariff structure now is circulating among partners in the Northwest consortium; it is expected to be filed with FERC late this year.

- Appointment by President Carter and approval by Congress of a Federal Inspector. Jack Rhett, an Environmental Protection Agency official and former employee of the Army Corps of Engineers, is reported to be the leading candidate. Walt Parker, co-chairman of the Federal-State Land Use Planning Commission, also is under consideration. State officials expected a formal nomination to Congress months ago. Gov. Jay Hammond wrote President Carter a letter in early August urging quick action on the appointment. Hammond said "divisive wrangling" among the federal agencies had left the federal government's effort to build the pipeline "wholly without leadership."

- Reorganization of the federal bureaucracy to facilitate pipeline construction oversight. This reorganization, mandated by the "President's Decision and Report to Congress" that selected the Alaska Highway route over two competing proposals, will transfer to the Federal Inspector field-level supervisory authority over other federal agencies holding responsibility for various aspects of gas line construction. Congress must approve this reorganization.

- A decision by FERC on pipeline pressure and other design and engineering matters. A report from FERC is expected any day.

CANADA RECONSIDERS PLAN TO PRE-BUILD SOUTHERN PORTIONS OF THE GAS LINE

Published reports[1] indicate that delay in the United States is creating problems for the pipeline companies that will build the Canadian sections of the Alaska Highway gas pipeline project.

"Pre-building" the southern sections of the Alaska project, to allow earlier delivery of Alberta gas into the United States, has been promoted as a way to ease financing of the overall project. However, there is now talk in Canada of possibly expanding existing TransCanada pipelines for the export of excess Alberta gas (called "bubble" gas) instead of using pre-built facilities of the Alaska Highway project.

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[1] Oilweek, August 21, 1978; Western Interstate Energy Board Newsletter No. 78-32, Sept. 1, 1978.

Proposals by a group of Alberta natural gas producers, called the "ProGas" consortium, to expand existing pipelines could threaten the planned pre-building of the southern section of the Alaska Highway gas line. The ProGas group is managed by Vern Horte, former president of Canada Arctic Gas Pipeline Ltd., which backed the losing Arctic Gas route through the Mackenzie Valley.

Although the Foothills Pipe Lines consortium, which will construct the Canadian sections of the Alaska Highway gas line, has officially maintained that pre-building of the southern portions is not critical to success of the overall project, spokesmen say Foothills will fight any project that threatens pre-building.

FERC already has demonstrated its support of the pre-building concept by giving Northwest Alaskan conditional approval to import 1.04 billion cubic feet a day of Canadian gas from PanAlberta Gas Co. Ltd. (U. S. import approval means nothing without Canadian approval, now under debate.)

It is possible that both the Foothills pre-building and ProGas expansion schemes could proceed, but this will depend on how much gas the Canadian National Energy Board determines is available for export. The National Energy Board will conduct public hearings in October and November on Canada's gas supply and demand requirements, and it is expected to submit a report to the federal cabinet by the end of the year.

In a related matter, two Lower 48 pipeline companies have challenged in court FERC's action granting conditional import approval to Northwest. Midwestern Gas Transmission Company and Michigan Wisconsin Pipe Line Company appealed FERC's refusal to conduct a rehearing on the matter to the U. S. Court of Appeals, District of Columbia Circuit.

While knowledgeable opinions on the significance and likely success of the Midwestern suit vary widely, Northwest Alaskan "believes there is no foundation for the appeals," the company said in a recent newsletter. "The project's sponsors view the FERC's action as carrying out the President's Decision and Report to Congress to: 1) consider early construction for Alberta gas imports an integral part of the pipeline system; and 2) aid in the expeditious processing of all necessary government approvals."

INTERIM COMMITTEE ON GAS LINE FINANCING ORGANIZES

A legislative interim committee directed to study the possibility of a $500 million direct investment by the state in the gas pipeline met September 7 and 21 in Anchorage. The committee was created by a resolution of the last legislature.

The committee has approved an $85,000 study on the marketability of Alaska gas in the Lower 48 by the University of Alaska's Institute of Social and Economic Research, and $12,000 for a technical symposium that will bring together econometric model builders in Alaska. The committee also has tentatively agreed to retain the law firm of Birch, Horton, Bittner & Monroe of Washington, D. C. and Alaska for advice on legal and regulatory matters.

In testimony September 21, Northwest officials said their company has not yet formally asked Congress to approve a change in Section 103 of the Internal Revenue Service Code. This change is necessary before the Alaska Gas Pipeline Financing Authority, which was created by the legislature last session, can issue $1 billion in tax-exempt revenue bonds for the project. Northwest officials said they have postponed seeking the IRS change until Congress acts on the natural gas bill. They said they are optimistic that both the natural gas bill and the IRS change will be approved by Congress this year. They confirmed earlier reports that completion of pipeline construction will be delayed about a year.

In response to questions, Northwest officials told the committee the company soon will submit updated cost estimates and a revised timetable.

Committee members are Senators Frank Ferguson, Bill Sumner and Mike Colletta, and Representatives Bill Miles, Terry Gardiner and C. V. "Chat" Chatterton. So far, the committee has not elected a chairman.

RADER NOMINATED TO NORTHWEST BOARD

Retiring Senate President John Rader, Gov. Hammond's nominee to serve on the Board of Directors of Northwest Alaskan, says he expects his formal election to the board will come later this fall. Rader would serve as an ex officio, non-voting member of the board.

Legislation enacted last session creating the Alaska Gas Pipeline Financing Authority directed the governor to nominate a public member to represent the state on the Northwest Alaskan Board of Directors, subject to approval of the board.

Northwest Alaskan, one of the six partners making up the Alaskan Northwest consortium, serves as operating partner for the group.

STATE RECONSIDERS PLAN TO SELL ROYALTY GAS

Officials in the Department of Natural Resources are reevaluating the state's announced intention to sell the Prudhoe Bay royalty gas and gas liquids next spring.

Commissioner Robert LeResche said recently he doubts the sale can proceed as scheduled, given all the uncertainties surrounding the pipeline project, even if Congress sets the price for Alaska gas immediately.

The department has circulated a "general notice and solicitation" to 500 firms announcing the proposed sale and setting out a tentative timetable. However, the state received only 23 letters of interest; all responses were brief and provided little concrete detail on in-state development plans. The schedule outlined in the July 19 solicitation anticipated that a final decision on whether to hold the sale would be made in March, after the legislature had reviewed and approved a "draft contract" and criteria for selecting a bidder. If a decision were made to go forward with the sale, bidders would submit "final development plans" and sealed bids in late March. The legislature then would approve a specific contract to be selected by the administration.

LeResche said this change in procedure was partly in response to criticism the administration received during the royalty oil sale to Alpetco last spring.

Of the 23 responses, North Pole Refining submitted one of the most detailed, saying it has undertaken an economic study of markets and transportation to determine whether a petrochemical facility (processing ethanes, propanes and butanes) could operate profitably in the Fairbanks-Interior region.

LeResche said the department and the Royalty Oil and Gas Development Advisory Board will continue to work with interested firms in developing plans for in-state use. In conjunction with that effort, the department is considering proposals from four consulting firms to assist the state in promoting petrochemical development.

GRAVEL'S GSOP GAINS GROUND

The U. S. Senate Finance Committee has endorsed Sen. Mike Gravel's General Stock Ownership Plan (GSOP), a scheme that would allow Alaska citizens to own shares of large energy projects such as the gas pipeline.

Gravel calls his plan "a landmark in the effort to spread the wealth more fairly without undermining the free enterprise system." Gravel predicts that the GSOP, if approved by Congress and the President, could mean $500 dividend checks to Alaskans as early as 1980, increasing gradually to $3,000 by the year 2000.

Gravel said persuading the Senate Finance Committee to attach the GSOP to the omnibus tax bill was the biggest obstacle to approval. The proposed GSOP would receive tax treatment similar to the Employee Stock Ownership Plans (ESOP) developed under IRS pension provisions more than 20 years ago, while expanding the category of eligible individuals beyond the employees of a single company. The GSOP trust would have to be sponsored by a state government; eligibility would be open to all residents of the state.

Gravel told the Senate when he introduced the legislation in June that if the State of Alaska chooses to make an equity investment in the gas pipeline, he thinks the citizens of Alaska should directly own that equity.

Financial consultant Louis Kelso, who developed the ESOP and GSOP, currently is designing an Alaska GSOP under a $180,000 contract with the Legislative Finance Division.

HAMMOND POSTPONES POINT THOMSON OIL AND GAS LEASE SALE

The state will not hold a North Slope oil and gas lease sale this fall as originally planned, Gov. Hammond announced recently.

The state had planned to lease acreage near Exxon's announced discoveries at Flaxman Island and Point Thomson, about 60 miles east of the Alyeska pipeline, on October 17. This would have been the state's first North Slope lease sale in more than nine years.

In a statement released September 15, the governor cited the federal government's failure to deal with the West Coast oil surplus, objections from local residents and the oil industry, lack of environmental data, and a dispute with the Interior Department over title to the lands as reasons for the postponement. Hammond said the problems are of such magnitude that they cannot be resolved before the federal-state Beaufort Sea lease sale, now scheduled for December, 1979. (See next item.)

Local residents in Barrow, Nuiqsut and Kaktovik expressed almost unanimous opposition to the sale at hearings conducted by the Department of Natural Resources this summer. The North Slope residents said they feared further oil development would destroy their subsistence resources and lifestyle.

Several oil companies also objected to the sale, citing legal problems that could lead to litigation and a desire for more exploration time.

The West Coast oil surplus, which daily forces about 600,000 barrels of Alaska crude to be shipped through the Panama Canal to the U. S. Gulf coast, has depressed wellhead prices for some Prudhoe oil to as little as $1.17 a barrel. The weighted average for all Prudhoe oil has dropped to about $4.38 a barrel.

"We cannot expect producers to pay full value for leases, nor can we expect to gain full value for oil produced from these leases until this market problem is solved," the governor said. "I do not intend to sell resources belonging to the people of Alaska at the cut-rate prices which are resulting from the federal Department of Energy's inaction."

PLANS PROCEED FOR BEAUFORT SEA SALE

With cancellation of the Point Thomson sale, attention now turns to preparations for a major federal-state offshore sale in the Beaufort Sea in December, 1979.

In July, The U. S. Interior Department and the state announced selection of 186 tracts (about 514,200 acres) proposed for inclusion in the sale. The tracts were selected for further social, economic and environmental study based on industry interest and a preliminary assessment of their oil and gas potential. The tracts lie from four to 20 miles offshore in an area between the National Petroleum Reserve in Alaska and the Arctic National Wildlife Range.

The federal Bureau of Land Management is preparing a draft environmental impact statement, and the state will prepare a social, economic and environmental analysis on portions of the proposed sale area. Public hearings on these documents are scheduled for May, 1979.

After the final environmental impact statement is completed next August, the governor and the Interior secretary will decide whether to hold the sale.

The proposed Beaufort Sea sale already is generating vigorous opposition from North Slope residents and environmental groups, who claim that current technology is inadequate to protect the Arctic from the risks of offshore drilling. News reports indicate that the Greenpeace Foundation of Portland, Ore., and other national environmental groups are gearing up to mount a campaign against the Beaufort sale.

FEDERAL GOVERNMENT PONDERS OIL SURPLUS

Three task forces in the federal Department of Energy are considering solutions to reduce the growing surplus of heavy-sour crude oil on the West Coast.

The federal government already has eased restrictions on the export of California residual fuel oil from the West Coast, and state officials are moderately optimistic that these changes portend a more comprehensive solution.

The West Coast surplus has held state revenues from royalties and severance taxes far below levels predicted several years ago. The state has been arguing that failure to relieve the surplus will severely curtail future oil exploration and development in Alaska and undermine the federal government's effort to increase domestic production and cut foreign oil imports.

Members of the Alaska administration and legislature have worked since last spring with California officials to develop a three-point plan for relieving the surplus: convert ("retrofit") and equip existing West Coast refineries to handle more Alaska and California crude oil, construct one or more of the proposed west-to-east pipelines, and permit the export or exchange of North Slope and California crude oil.

Export of Alaska crude is prohibited by law unless approved by the President and the Congress. Thus, Alaska's strategy has been to seek and propose solutions that accommodate both national and state concerns.

In testimony before a Congressional subcommittee August 21, Revenue Commissioner Sterling Gallagher warned that continued federal inaction may curtail future Alaska oil production.

"If the federal government is not interested in taking the action needed to solve the situation, then I am afraid that badly needed oil and gas in the Alaskan Arctic and in California will not be developed beyond current production levels. In addition, the chance to reduce costly transportation charges and also to improve the nation's balance of payments situation will be lost," Gallagher said.

"If the federal government does not have the resolve to take effective action, then this inaction will have likely impact on the willingness of Alaska and industry to develop additional resources at this time and require Alaska to examine all courses of action which it might take without federal participation," he said.

Rep. C. V. "Chat" Chatterton, testifying at the same hearing before the Special Investigations Subcommittee of the House Interior and Insular Affairs Committee, urged that restrictions be lifted to allow the export of Alaska oil.

"The optimal fiscal interests of the people of Alaska can best be served by Congress' outright repeal of those sections of PL 93-153, the Trans-Alaska Pipeline Authorization Act, which restricts Alaskan oil transported through the Alyeska Pipe Line to being marketed in the U. S. unless presidential and congressional approval is obtained for exemption," Chatterton said.

Chatterton serves on a joint interim West Coast Oil Surplus Committee, which is chaired by Rep. Clark Gruening. The committee has retained consultant Arlon Tussing and also has approved a $145,000 study, to be conducted by Battelle Pacific Northwest Laboratories, on future West Coast supply-demand balances and limits to refinery expansion.

FOOTHILLS CONSORTIUM PROPOSES OIL PIPELINE THROUGH CANADA

Officials of a Canadian pipeline consortium toured Alaska recently seeking support for new alternatives to transport North Slope crude to inland U. S. markets.

Foothills Oil Pipe Line Ltd., jointly owned by Alberta Gas Trunk Line and Westcoast Transmission, would like to build an oil pipeline paralleling the Alaska Highway gas pipeline or an oil pipeline originating in Skagway. (Foothills is also sponsoring the Canadian portions of the Alaska Highway gas line project.)

One alternative proposed would route the new oil line from Delta Junction near Fairbanks down the gas line corridor into Edmonton, where the oil would then enter existing pipelines for transport to the mid-eastern United States. However, this would leave the southern portions of TAPS underutilized, assuming North Slope production remains at its current level. Foothills officials said Sohio, the producer with the most surplus oil and a major customer for any new line, would have to pay the full TAPS tariff to Valdez, even if the oil were diverted to a new line near Fairbanks. (This is the same problem faced by North Pole Refining, which is charged the full tariff even though it takes its oil out at Fairbanks.)

In an attempt to accommodate Sohio's problem, Foothills developed a second alternative. Under this plan, oil would be moved in small tankers from Valdez to Skagway, and a new pipeline would be constructed along the Alaska Highway corridor to connect with existing lines in Canada. Foothills officials also envision a major oil port at Haines to accept supertankers carrying sweet, foreign oil, which would be shipped by smaller tankers or a new pipeline to the less accessible Skagway port.

Foothills officials said they already have made several presentations to the federal Department of Energy, although they have not filed a formal application with the Federal Energy Regulatory Commission.

"We are here now because your Department of Energy says it's time to decide if we want to proceed with a formal application," Ed Phillips, senior vice president of Foothills Oil Pipe Line Ltd., said during a visit to Juneau September 21. "We're looking for a consensus and not the adversary hearings we had with the gas line."

Foothills officials said they considered their proposed oil pipeline to be competing with two long-standing proposals to move Alaska oil to U. S. inland markets by northern pipelines. One would involve shipping oil to Kitimat, British Columbia, where it would move by pipeline to Edmonton, Alberta, and then into existing pipelines. The so-called Northern Tier proposal would require a major oil port at Port Angeles, Wash., and construction of a new pipeline across the northern states to the Midwest. Both proposals have met stiff opposition from environmentalists, fishermen and others.

Phillips predicted that Canada's National Energy Board would finally and formally reject the Kitimat proposal within two weeks.

President Carter has asked Foothills for a formal proposal by the end of the year, Phillips said. He said he expected Carter to make a formal Presidential decision selecting one of the competing northern pipeline routes sometime after May, 1979, when the Department of Energy will make a recommendation.

The Canadian and American governments have been reluctant to approve the Kitimat and Port Angeles port sites, Phillips said, because many believe environmental risks outweigh potential benefits. Alaskans might view an Alaska oil port differently, he speculated, since the state stands to gain relief from the West Coast surplus and increased revenues from higher wellhead prices.

Foothills would build the new oil line in partnership with Northwest Pipeline Corporation of Salt Lake City, the same firm sponsoring the Alaska portions of the gas line.

While in Alaska, Foothills officials briefed legislators and high-ranking members of the administration, and met informally with environmental groups, the Coast Guard, and the Skagway and Haines Chambers of Commerce.

ALPETCO SEEKS SITE FOR PETROCHEMICAL FACILITY

Alaska Petrochemical Co., winner of the right to purchase 150,000 barrels a day of state royalty oil, has selected four potential sites for its refinery and petrochemical facility.

The four sites are City of Valdez, City of Seward, Kenai Native Association (Wildwood site) and the Matanuska-Susitna Borough (Pt. McKenzie and others). Under terms of the contract signed with the state last spring, Alpetco must make its final choice by December 18.

The company is conducting subsurface soil tests at each location, as well as preliminary environmental, resource and social studies.

In August, Alpetco representatives met in Tokyo to discuss participation in the project with several Japanese groups. Charles Honig, board chairman and president of Alaska Interstate Co. (which owns 60 percent of Alpetco), said Japanese interest in the project is "most encouraging."

COMMITTEE STUDIES COMPREHENSIVE ENERGY POLICY

The State Energy Policy Committee, chaired by Rep. Bill Miles, has been working during the interim to develop a comprehensive state policy encompassing a broad range of energy issues.

The committee is studying the relationships between the state departments, divisions and regulatory agencies that deal with energy matters; the state's approach to energy conservation; the use and development of conventional (oil, gas, coal, hydroelectric) and alternative (solar, wind, tidal, geothermal) energy resources; and the state's perspective on and conformance with national energy policy.

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LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

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-- Compiled by Kay Brown, Policy Analyst --

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NORTHWEST DISTRESSED BY "BUREAUCRATIC DELAY," WINS IN COURT

A financial advisor to the Alaskan Northwest pipeline consortium says the possibility of obtaining private financing for the $12 billion project "looks pretty grim at the moment."

"Basically, we are very pessimistic about the probability of private financing because of the ever-increasing entanglement of the Washington bureaucracy and the delays caused by Washington," said Mike Stanfield, vice president of Loeb Rhoades, Hornblower and Co., a Northwest advisor.

"I'm not saying we're dead, but the government has got to wake up and change things," Stanfield said. "It's all in Washington's hands. They are going to have to decide whether they want the pipeline or not, and if they do, they're going to have to change some things."

Stanfield said the failure of the Federal Energy Regulatory Commission to resolve the Incentive Rate of Return on equity, the pipeline's design, and the ownership and cost responsibility for the North Slope conditioning facilities are only a few of the partnership's problems.

"The Federal Inspector was supposed to have been appointed 14 months ago. Because that hasn't happened, a number of other federal agencies are working counter to each other and to us," he said.

The consortium's Board of Partners recently reduced the operating budget substantially, Stanfield said, but he declined to give details.

Stanfield said FERC's November 29 order on the Incentive Rate of Return didn't resolve any substantive issues.

"We don't consider it a decision, but rather a furtherance of bureaucratic red tape," he said. "We're very distressed by the fact that they didn't decide anything."

FERC deferred action and scheduled a hearing on one of the main issues considered a problem by Northwest--whether the Allowance for Funds Used During Construction (AFUDC) account should be included in the ratio of actual construction costs to projected construction costs. This ratio will serve as the basis for determining what rate of return the project is allowed to earn on equity.

The Incentive Rate of Return (IROR), mandated in the President's Decision and Report to Congress selecting the Alaska Highway route through Canada, is designed to control construction cost overruns. The IROR would allow pipeline companies and other equity investors to earn a high rate of return if the project is constructed within or under budget, but would reduce earnings if the project ultimately costs more than projections.

FERC has proposed that AFUDC funds be included in the actual construction costs used to determine the cost performance ratio on which IROR will be based. Alaskan Northwest has said inclusion of this factor could jeopardize private financing because it penalizes the project sponsors for government-caused delay and other factors beyond their control. Any delay in construction will increase the AFUDC account, which would reduce the allowed rate of return under FERC's present IROR proposal.

"One of the basic problems is that none of FERC's decisions is final; everything is subject to reconsideration," Stanfield said. "They are not doing anything but creating paperwork and causing anxiety."

Earlier in November, John G. McMillian, chairman and chief executive officer of Northwest Alaskan, told a press conference in Washington, D.C., that the company remains optimistic about private financing.

"Rumors of our demise have been greatly over-exaggerated," McMillian was quoted in press accounts as saying. "We still believe, given the conditions that we hope will be approved by the Federal Energy Regulatory Commission, that we can finance the project privately, without government aid."

McMillian said, however, that FERC's Incentive Rate of Return proposal must be modified along lines suggested by Northwest in order for private financing to be achieved.

McMillian also said Northwest will need government support in the form of tax-exempt status for $1 billion in bonds to be issued by the State of Alaska. Congress last session failed to pass a change in the IRS code that would have allowed issuance of the bonds, but McMillian said his company will try again next year to get the necessary changes approved.

However, Sen. Mike Gravel told a San Francisco meeting of the legislature's Gas Pipeline Financing Committee that it appears the proposed IRS change is "dead for now" due to opposition of the Treasury Department and others.

On November 14, the same day as McMillian's press conference, the New York Times reported that: "Financially, the gas pipeline faces so formidable a series of hurdles that it ultimately may require outright Federal financing, industry sources expect."

But not all the news has been gloom and despair for supporters of the pipeline project.

The U. S. Court of Appeals, District of Columbia Circuit, recently dismissed an appeal by two Lower 48 pipeline companies to review a FERC order granting Northwest Alaskan conditional approval to import Canadian gas.

Northwest wants to import 1.04 billion cubic feet of gas a day from Pan-Alberta Gas Ltd. and deliver it through "pre-built" southern sections of

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the Alaska Highway gas pipeline. Although this arrangement has been conditionally approved by FERC, the Canadian government has not yet granted export permission.

Midwestern Gas Transmission Co. and Michigan Wisconsin Pipe Line Co. had challenged FERC orders on a number of grounds, including lack of authority, an inadequate record, anti-trust violations, and violations of constitutional and statutory rights to a hearing.

In its November 2 ruling, the court affirmed FERC's jurisdiction to act on the matter under the Alaska Natural Gas Transportation Act and the Natural Gas Act. The court dismissed several challenges to the merits of the Commission's decision as not ripe for review. With respect to the single issue found ripe for review--whether FERC unlawfully refused to hold a hearing before issuing the conditional authorization to Northwest--the court upheld FERC's action as within the bounds of the Constitution and the Natural Gas Act.

A few days after the court decision, the companies responsible for the Western Leg of the Alaska Highway project filed applications with FERC seeking the necessary authorizations.

Northwest Alaskan applied for permission to sell up to 240 million cubic feet of Alberta gas a day to Pacific Interstate Transmission Co. (a subsidiary of Pacific Lighting Corp.) for ultimate delivery to markets in southern California. Related applications were filed by Pacific Transmission Co., Northwest Pipeline Corp., El Paso Natural Gas Co. and Pacific Interstate. Together, the applications would accomplish delivery of this gas from the International Boundary near Kingsgate, British Columbia, to the Arizona-California border, where Pacific Interstate would sell the gas to Southern California Gas Co.

The remainder of the 1.04 Bcf/d imported from Pan-Alberta, or about 800 million cubic feet a day, will be delivered at Monchy, Saskatchewan, and purchased from Northwest Alaskan by United Gas Pipe Line Co., Panhandle Eastern Pipe Line Co. and Northern Natural Gas Co.

ALASKA HIGHWAY GAS PIPELINE THREATENED BY CHANGING ENERGY OUTLOOK

A legislative consultant says the Alaska Highway gas pipeline, faced with competition from Mexican, Canadian and growing surpluses of Lower 48 gas, may be delayed indefinitely unless significant progress is made in the next several months.

Consultant Arlon Tussing told the legislature's Gas Pipeline Financing Committee at an Anchorage meeting November 27 that the energy supply picture in North America is changing rapidly and that competition from other supplies could make expensive arctic gas unmarketable.

"Oil and gas in North America is going to be coming on stream faster than demand is going to grow in the next four to five years," Tussing said. "The availability of conventional energy in North America has been greatly underestimated...Mexico is not a myth. The finds in Mexico are far bigger than anything ever expected in conventional resources in North America..."

Higher prices allowed under the new Natural Gas Policy Act of 1978 have created a current gas surplus of about 1 trillion cubic feet in Lower 48 markets, and energy officials say the surplus may last for three to five years.

Tussing said Energy Secretary Schlesinger and the CIA have been aware of large Mexican discoveries for three years, and yet they deliberately and self-servingly ignored and concealed these supplies in order to push President Carter's energy program through Congress.

Carter's energy strategy is based on the premise that the world is running out of conventional energy and that a "crunch" or tightening of supplies will confront the nation sometime in the 1980s. This view gained wide acceptance after the 1973-74 Arab embargo and quadrupling of oil prices.

"The crunch doesn't look as imminent as it did several years ago," Tussing said. "I don't think there's going to be a crunch, but you can't know for sure, you can't predict."

In any event, he said, the uncertainty of the situation is going to have a significant impact on the willingness of gas companies in the Lower 48 to sign long-term contracts for high-cost gas, on the willingness of institutional investors to invest in high-cost projects, on the willingness of state public utility commissions to approve high-cost purchases, and on the willingness of Congress to consider financial backstopping.

If the real price of oil doubles by 1985 as Department of Energy officials and Exxon predict, Tussing said, the market will be able to absorb all the gas that can be transported from the Arctic by pipeline. But if not, the market won't accept Alaska gas without federal subsidy.

"One of the things the state is going to have to face up to with respect to this project and its oil policies is the possibility that the world will face a buyers' market in energy for the next three to five years, and maybe to the turn of the century. Economic strategies that depend on a sellers' market, that assume Arctic resources will be needed, will have to be reassessed," Tussing said.

Tussing presented to the committee the first part of a study that he and Connie Barlow are conducting under an $85,000 contract between the University of Alaska's Institute of Social and Economic Research and the Research Division of the Legislative Affairs Agency. Tussing described the report, titled "An Introduction to the Gas Industry, with special reference to the proposed Alaska Highway gas pipeline," as an attempt to explain in plain English what gas is, how it is sold and marketed, how gas projects are financed, and how government regulates the industry. Copies of the report are available from the Anchorage and Fairbanks legislative information offices or from the Research Division of the Legislative Affairs Agency.

When asked by Sen. Bill Sumner for his "best guess" of how long the gas line sponsors have to put the pieces together, considering all the variables, Tussing responded: "You may well be faced with making the decision of whether to go with it or kill it in this upcoming legislative session. I don't know. The sponsors cannot say this thing is precarious or that it may fall apart at any moment. Their emphasis is on maintaining momentum, on maintaining everybody's conviction that this is a viable project, that things are happening step-by-step. But if you have six months or a year when nothing happens, this erosion (of the political climate) can be fatal...A federal pipeline coordinator hasn't been appointed, there haven't been sales or transportation contracts, there are no firm financial commitments from the banks, and so on. The state may have to make the next move, or series of next moves, dramatic ones to keep the project alive."

The sponsors of the Alaska sections of the pipeline have asked the state to contribute $500 million in equity to the project, and have been pushing for an early state commitment. Committee Co-chairman Rep. Bill Miles and Natural Resources Deputy Commissioner Fred Boness agreed, however, that it will not be possible to have a recommendation on equity financing ready for the legislature when it convenes in January.

One of the next big hurdles faced by the pipeline sponsors is to secure sales contracts for the gas. Negotiations between the North Slope producers and the pipeline companies were unable to proceed until Congress passed the Natural Gas Policy Act of 1978, which set a Prudhoe Bay wellhead ceiling of $1.45 per million BTUs as of April, 1977, plus inflation.

Tussing said gas sale negotiations have not progressed very rapidly because details of implementing the bill still are being worked out by FERC. The protracted debate in Congress over the energy bill has had two adverse effects on the gas line, Tussing said.

"First, it has delayed us to the point that the whole energy picture has changed, and second, it has held out to the state and the producers a totally unrealistic price. We both would have been tickled to get 75¢ plus inflation. This puts the legislature in a tough spot. Can you politically agree to a 65¢ or 75¢ price, even if the producers were willing to? At least one of the producers indicates they're going to hold out hell or high water for the ceiling," Tussing said.

Frank Zarb, who headed the Federal Energy Administration under former President Ford, said during a visit in Juneau December 5 that it is his "best judgment at the moment" that the Alaska Highway gas line cannot be financed in its present form. Zarb, a non-paid advisor to Gov. Hammond and a general partner in the investment banking firm Lazard Freres & Co., said increased supplies of Canadian, Mexican and non-conventional Lower 48 gas may make investors unwilling to finance the pipeline.

"Three years ago, we could have ridden (the pipeline) on a white horse. We could have sold all kinds of gimmicks to support it. But, conditions have changed," Zarb said.

Zarb said he doesn't think an equity investment by the state will make the difference in whether the pipeline is built or not.

Zarb did not rule out congressional support, in the form of federal subsidy, for the line. He said that once people realize that short-term gas surpluses will be exhausted in the 1980s, they may conclude that it is in the national interest to go ahead and build the line today, when it would cost less.

Legislative consultant Milton Lipton, in a presentation to the Legislative Council December 6, said he thinks the gas line eventually will be built, although it is likely to be delayed.

The new Canadian and Mexican gas supplies may affect the timing of gas pipeline construction, he said. The sooner firm commitments can be arranged, he said, the more likely it is that the line will be built. If there is too long a delay, Lipton said, U. S. policy makers may reassess their commitment to the Alaska pipeline and attempt to rely on Mexican gas.

ALASKA URGES 1440-psig PRESSURE FOR GAS PIPELINE

The State of Alaska has asked the Federal Energy Regulatory Commission to select 1440-psig as the operating pressure for the proposed Alaska Highway gas pipeline.

Alaska submitted its comments in response to a report by FERC's Alaska Gas Project Office (AGPO) that favored a 1260-psig operating pressure. The full commission has yet to address the matter, and the AGPO report was not an official FERC finding.

Alaska urged FERC to hold a hearing in the near future to gather additional information on the pressure question, saying it does not believe "the commission now has the legal or factual foundation to issue an order establishing the system pressure."

The higher pressure 1440 system would be able to carry a greater volume of gas and of Natural Gas Liquids (NGLs), specifically butane. If the butane is left in the gas stream, its presence will raise the BTU value of the gas, Alaska said. "Gas consumers would receive a direct, valuable benefit: higher heating value than they would otherwise receive because of the presence of natural gas liquids not used for petrochemicals," the state said.

"Moreover, a 1440 system has the promise of more efficient, lower cost operation as higher throughputs occur. Alaska believes the relatively small additional costs are a worthwhile premium for its future."

Atlantic Richfield, one of the major North Slope producers, also urged FERC to approve a 1440 psig system, while Sohio told FERC it favors a 1260 system. The Alaskan Northwest pipeline consortium, which will build the Alaska sections of the pipeline, strongly favors the lower-pressure, 1260 alternative.

The partnership is proceeding with design, environmental and cost-estimating activities on the assumption that pressure will be 1260 and throughput will be 2.0 to 2.4 billion cubic feet a day. "Changes in these assumptions will cause substantial delay," Northwest Alaskan said in recent comments.

The partnership agrees with the AGPO report that "in order to justify an increase from the presently proposed pressure level of 1260 psig, it would be necessary to (1) receive the concurrence of the Canadian government, (2) assure that the consumer will benefit from the decision, and (3) assure that the project can still be privately financed," Northwest said.

If a system higher than 1260 is selected, Northwest said, the Canadian government will require extensive testing, which would delay the project about two years and "adversely affect the system economics."

The State of Alaska, however, said in its comments that testing a 1440 system may not be significantly different than testing a 1260 system. "Alaska suspects...the degree of technological advance is relatively the same for each as is the testing required."

Northwest, which asked FERC to resolve the matter "as soon as possible," said there has been "no demonstration by the producers or others that sufficient gas supply will be available to fully utilize the capacity of the higher pressure system and thereby achieve the potential economic benefit....[T]hroughput volumes over 3.0 billion cubic feet per day appear unlikely; and the prospect of achieving 4.0 billion cubic feet per day from Alaska is highly remote. In view of these considerations, the judgment to construct the 1260 psig system is sound."

Yet the state said the lower 1260 pressure would be "less than optimally designed given the potential of Alaskan reserves. The costs of later adding capacity to the gas line are substantial and suggest the advantages of building extra capacity now as an insurance policy."

LEGISLATORS VISIT CANADA

Preparations for the Alaska Highway gas pipeline are proceeding much faster in Canada than in the United States, Reps. Bill Miles, Terry Gardiner and Sam Cotten learned on a recent nine-day tour of Canada.

The legislators visited Calgary, Edmonton, Toronto and Ottawa, and met with dozens of industry and government officials.

"The major finding stemming from the Gas Pipeline Committee's visit to Canada is that the Canadian portion of the Alaska Highway Pipeline Project is ready to proceed and that Canadians support the overall project," Legislative Affairs staffer Larry Eppenbach, who also made the trip, said in a preliminary report. "The readiness of the Canadian segment of the pipeline with respect to the major regulatory and financial issues was clearly displayed."

The legislators also found that:

-- The Canadian National Energy Board (NEB) will complete gas demand and supply studies by February and should act on specific export proposals by next July.

-- The Northern Pipeline Agency (NPA), created by act of Parliament last April, is now fully operational and moving effectively to address Native claims, labor, construction and permitting issues. NPA does not expect the claims issue to impede pipeline construction. Local hire is specially provided by Canadian law granting a preference to Native northerners.

-- Any pre-building of the southern portion of the pipeline, to support early export of Alberta gas, will depend on sufficient assurances (in the form of gas sales contracts and financial commitments) that the northern portion of the line will be built.

-- The Foothills Pipeline consortium, sponsors of the Canadian segments, intends to raise about $1 billion of equity capital in Canada and about $4 billion of debt in the United States, where interest rates on debt capital generally are lower. Financing for the Canadian sections should be available on reasonable terms once financial commitments are made for the U. S. segments.

-- The Alberta Heritage Fund, a nearly $4 billion trust fund of Alberta Province, has not been asked to help finance the Foothills project. The fund would consider participation only with respect to debt financing.

The legislators also found that the relationship between the Canadian oil industry and government is markedly different than in the United States. A number of Canadian government and quasi-government organizations are directly engaged in the oil and gas business, including:

-- Petro-Canada, a crown corporation owned by the federal government, which has options on federal leases and a $1.5 billion capital draw on the treasury. The corporation owns one-third of West Coast Transmission Co., has investments in the Arctic Island area, and has proposed moving gas from the Arctic Islands to the East Coast by LNG tankers.

-- Alberta Energy Company, which is jointly owned by Alberta Province and small Canadian shareholders. The company owns gas development leases, a synthetic crude pipeline and coal mine, and is proposing a synthetic natural gas and petrochemical project.

-- Alberta Gas Trunkline, one of the major gas transmission, exploration and development companies in Canada. AGTL is a major participant in the Foothills project and has recently purchased Husky Oil Co. AGTL began as a government-supported corporation and continues to have three members of its board of directors appointed by the Alberta government.

-- Trans-Canada, a regulated public utility that owns and operates the largest gas transmission facility in North America. The Canadian government formerly owned a portion of Trans-Canada, but successful operation in the 1960s provided sufficient revenues to pay back the Canadian government for its ownership share.

PRUDHOE RESERVOIR STUDY PROGRESSES

Rep. Chat Chatterton, Gregg Erickson, and Dr. Todd Doscher, the legislature's reservoir engineering consultant, recently met in Denver with H. K. van Poollen and his staff to review progress on the three-dimensional Prudhoe Bay reservoir simulation study. Van Poollen is conducting the study under contract with the state Division of Oil and Gas. Joe Green, project officer for the division on this study, also attended.

All participants at the meeting generally agreed that the study is coming along in good order. Due to the need for some additional technical analysis, which all parties at the November 27 meeting agreed was necessary, results of the work originally scheduled for completion in February now are expected in late March.

The results of this study should provide the legislature with the best available information on such critical questions as the amount of oil that may be lost over the life of the field as a consequence of gas production for sale, and the effects of water injection into the field. The simulation study will not in any sense be final, however, since geological information derived from continued development drilling and information gained from production history will need to be continually updated to keep the model current. Those participating in the meeting generally agreed that the consultants, the Division of Oil and Gas, the producers, and others with interests in the field have reached agreement on broad outlines for the model's structure.

LEGISLATURE AND ADMINISTRATION HIRE ENERGY CONSULTANTS

The Gas Pipeline Financing Committee has approved $25,000 for San Francisco consultant Louis Kelso to design a General Stock Ownership Corporation (GSOC) specifically for financing the gas pipeline.

The administration will contribute $10,000 to $15,000 for Kelso's gas line project, Sen. Mike Colletta told the committee at its Anchorage meeting November 27. The committee met with Kelso in San Francisco earlier in November to discuss the possibility of using the GSOC as an alternative to direct state investment in the pipeline. Kelso already has a $180,000 contract with the Legislative Finance Division to design a general Alaska GSOC.

The committee also approved a $125,000 contract with the White Weld/ Merrill Lynch consulting firm to compare the state's oil and gas "framework of taxes, contracts and regulation to those of other states, governments and organizations functioning as major petroleum resource owners." The firm will examine "the strengths and weaknesses of alternative institutional frameworks under which oil and gas resource development could take place in Alaska." Rep. Terry Gardiner was named project director.

Revenue Commissioner Sterling Gallagher has retained the Washington, D.C., law firm of Wilmer, Cutler & Pickering under a $5,000 contract to study how federal securities laws will affect the organization and operation of a GSOC. The firm already has produced a report.

In addition, Gallagher said the Department of Revenue has hired the National Economic Research Associates under a $70,000 contract to study gas pipeline tariff questions.

ALASKA OFFICIALS TO VISIT MEXICO

With prospects for gaining federal permission to export Alaska oil brightening, state officials will visit Mexico this month to lay the groundwork for a three-way swap between Mexico, Japan and Alaska.

Natural Resources Commissioner Robert LeResche and legislative consultant Arlon Tussing are scheduled to leave December 10 for Mexico, where they will meet with Jorge Diaz Serrano, head of Pemex, the national oil company.

Tussing said the purpose of the trip is "to get an informal, general understanding that Mexico will work with Alaska to put together an oil swap, with the first step being that Alaska royalty oil would be sent to Japan in return for Mexican oil exported to a refinery on the U. S. Gulf."

President Carter has scheduled a trip to Mexico February 14-16, and it has been reported he will discuss the proposed Alaska-Mexico oil swap with Mexican President Portillo.

Tussing has recommended that the state apply for a license to export Alaska royalty oil, which would require President Carter himself to make a decision on the matter. Such an "action-forcing" tactic likely will be necessary to overcome political fence-sitting by the Carter administration, Tussing said in a November 13 memo to LeResche and Rep. Clark Gruening, chairman of the legislature's interim West Coast Oil Surplus Study Subcommittee.

"Because the state's object is an open-ended procedure facilitating exports on a long-term basis, not just a single short-term royalty oil sale, (1) it is neither necessary nor politic to extract the last possible penny at the wellhead, if sacrificing some revenue would make this deal more acceptable to important political constituencies, while (2) a quite tolerable outcome would be for the President to turn down this deal and instead establish a general, permanent regulatory system for oil exports," Tussing said in the memo.

While any number of swap arrangements are possible, Tussing said, "the simplest arrangement from the state's standpoint would be one in which it had to deal with only one other party who would take possession of the Alaska crude, arrange the actual exchange, and pay the state for the foreign oil it imported into the United States. The most obvious choices for this role are major international oil companies, which have established relationships with Japanese refiners, owned or affiliated refineries in various parts of the United States, and tankers under charter. Thus, I would urge that, for simplicity, the first 'sample' royalty oil exchanges be negotiated on a one-stop basis with a major oil company."

In order to help overcome public and congressional opposition, it would be best if the oil imported in return for Alaskan exports was not Middle Eastern, but Mexican, North Sea or Indonesian.

"The logic of an exchange involving Mexico is the most powerful among the three alternatives," Tussing said, "because establishing such exchanges as a legitimate long-term logistical strategy would reduce the transport burdens on both Mexican and Alaskan oil--the former would be marketed around the Caribbean and on the East Coast of the United States, while the latter would be sold around the Pacific Basin. This arrangement could conceivably forestall the absurdity of having to build an unnecessary west to east pipeline in the United States or Canada."

Inside D.O.E., a weekly report published by McGraw-Hill, recently quoted unnamed DOE sources as saying that if the administration decides to approve the export of Alaska crude, Carter probably will make the announcement in June when restrictive legislation expires.

Tussing told the Gas Pipeline Financing Committee at its most recent meeting that he is "very optimistic" that exports for Alaska oil will be approved in the foreseeable future.

Administration energy advisor Frank Zarb, who opposed the export of Alaska oil when he worked for former President Ford, said he gives the swap proposal no better than a 40 percent chance of success. He said any swap involving Mexico would have to be part of a total resolution of U. S. and Mexican energy policies.

Zarb suggested that the state promote the swap on grounds it would benefit consumers and help reduce America's dependence on imported Arab oil.

FOOTHILLS OFFICIALLY PROPOSES SKAGWAY OIL PORT AND PIPELINE

Foothills Oil Pipe Line Ltd., a Canadian consortium that wants to build an oil pipeline from Skagway to Alberta to move Indonesian and surplus Alaska crude, recently filed formal application with the Secretary of the Interior seeking certification for the project.

Under the "Crude Oil Transportation Systems" law passed by the last Congress, President Carter will select a west-to-east oil pipeline from several competing proposals. Deadline for filing applications with the Secretary of the Interior was December 8.

The Foothills proposal is in direct competition with the proposed Northern Tier pipeline, which would run from Port Angeles, Washington, to Clearbrook, Minnesota.

Foothills' application was filed by the company's U. S. associate, Northwest Energy Co. of Salt Lake City. The proposed oil line would be built by the same companies sponsoring the Alaska Highway gas pipeline, including Northwest Energy Co. and Canada's Foothills Pipelines Ltd., a joint venture of West Coast Gas Transmission Co. and Alberta Gas Trunk-line.

The proposed oil pipeline, now estimated by the sponsors to cost about $950 million (1978 dollars), would run from Skagway across British Columbia and the Yukon Territory to Keg River in northwestern Alberta. Existing pipelines would carry the oil to Edmonton, Alberta, and into the U. S. Midwest.

Ron Rutherford, executive vice president of Foothills Oil Pipeline Ltd., said the average tariff from Skagway to Keg River will be about $1.02 per barrel. Transportation costs from the North Slope to Chicago, he said, will be about $8.30 per barrel. If the oil sells for $13 a barrel in Chicago, the North Slope wellhead would be about $4.70.

The company is pursuing the Skagway route, rather than an alternate overland route that would have connected with TAPS at Delta Junction near Fairbanks, because there does not appear to be enough North Slope oil to support the project for the number of years required, Rutherford said. The Skagway port will be able to accept oil from Indonesia, Saudi Arabia and other parts of Alaska. The Delta Junction route also would cost more, about $1.7 billion.

All tankers will go directly to Skagway, rather than to a tank farm at Haines as earlier proposed. As a concession to environmentalists, all tankers will go around Cape Ommaney and up Chatham Strait, rather than through Icy Strait as originally proposed.

Tanker traffic into Skagway will be slightly more than one tanker a day, and tankers will not exceed 81,000 tons.

Ed Phillips, president of Foothills Oil Pipeline Ltd., said he thinks Alaskans are going to support the project. "We were encouraged by the people we talked to in Alaska," he said. "If we'd had any red flags or signals that the state didn't want it, we wouldn't be committing to spend the millions of dollars it's going to cost to process this application."

However, opposition already is surfacing in the state. The state Division of Policy Development and Planning is currently writing an analysis of the Foothills proposal based on comments from eight state departments. Craig Lindh of DPDP said the analysis, which will be completed by the end of the year, will examine the pipeline's effect on wellhead values and the environmental risks of tanker shipments through Southeast Alaska, among other things.

The state Department of Fish and Game told DPDP it opposes a major oil port at Skagway.

"It is particularly distressing to see additional prime Alaskan fisheries subjected to environmental degradation as a result of inadequate foresight in routing the trans-Alaska oil pipeline," said Richard Logan, chief of Fish and Game's Habitat Protection.

"The demonstrated inadequacy of oil spill containment and cleanup capabilities in marine spills leaves a virtual guarantee that important marine resources and coastal habitat would be damaged in the event of a spill," Logan said in a memo to DPDP.

Revenue Commissioner Sterling Gallagher opposes the Foothills proposal on economic grounds, claiming it will produce a netback wellhead too low to stimulate development of economically marginal North Slope fields.

Gallagher says it is definitely more expensive to move Alaska oil by pipeline to the Midwest than to swap Alaska oil to Japan in exchange for Mexican oil delivered to the U. S. Gulf Coast.

"I'm not opposed to a pipeline as long as they don't expect to move Alaska oil down it," he told the Associated Press.

Foothills spokesman Rutherford said that if Alaska gets federal permission to export its oil, "there would be no need for this line. We view this as an alternative to exports," he said.

However, "it would be terrific if the state got temporary export permission until this line was built," Rutherford said.

GRAVEL PROPOSES REPEAL OF OIL EXPORT RESTRICTIONS

Sen. Mike Gravel will urge Congress when it convenes next year to lift restrictions on the export of Alaska oil, aide Deming Cowles says.

Gravel introduced a proposal to allow exports as an amendment to the omnibus tax bill in the closing days of the last congressional session, but it was not formally debated on the Senate floor.

Gravel's proposal would impose three conditions before exports could take place:

-- At least half of the exported oil would have to be transported in U. S. flag (Jones Act) tankers to its foreign destination.

-- The Trans-Alaska Pipeline would have to be "operating at full capacity." (The amendment does not define "full capacity.")

-- Contracts for exports could be terminated if the country's oil supply were interrupted or seriously threatened.

Gravel said his approach "would provide the requisite incentive to the producers of North Slope oil to take the steps necessary to expand North Slope production from 1.2 to at least 2.0 million barrels per day, the ultimate capacity of the Trans-Alaska Pipeline System."

Allowing exports would be in the national interest, Gravel said, because it would increase the nation's oil production capacity, lessen the impact of a future embargo, and improve the balance of trade.

"Today, as much as 800,000 barrels of oil per day--or some 10 percent of our existing domestic production--are not being developed and produced because of the lack of marketing opportunities. If we produced and exported that oil, our balance of trade with Japan would improve by some $4.066 billion per year," he said.

Cowles said prospects for easing restrictions on exports have improved considerably since President Carter announced a year and a half ago he would not authorize exports of Alaska crude. "A spokesman for the administration told us in September that they were very favorably disposed toward the idea, but that politically they couldn't do anything with it this year. I expect that next year they'll be looking at it very seriously, as well as at some other proposals and modifications (to Gravel's amendment)."

Export debate in the next Congress may center on 1977 amendments to the Export Administration Act, which expire June 22, 1979. These amendments impose the most severe restrictions on the export of Alaska oil, although two other federal statutes also restrict exports. Cowles said he expects the Senate Banking Committee will begin hearings on the Export Administration Act in February or March.

It seems unlikely the Alaska congressional delegation will be united on this issue.

Rep. Don Young, a supporter of the 1977 "McKinney amendment" that would have categorically prohibited exports of Alaska oil, is still "steadfastly opposed to exporting the oil," said aide Rod Moore.

"For a number of reasons, Mr. Young feels it is better to keep Alaska's oil in the American market....If you can transport that oil by pipeline, the construction and operation of those pipelines will supply greater employment and greater benefits to the nation," Moore said.

DOE STUDY SHOWS BENEFITS OF EXPORTS

Lifting the ban on the export of Alaska crude oil could save the nation between \$2 billion and \$18 billion in the next decade, a draft Department of Energy study says.

The draft study, which is now being reviewed by Energy Secretary Schlesinger, was prepared by DOE's Office of Policy and Evaluation.

The economic benefits to the nation would vary, the analysis says, depending on whether a west-to-east pipeline is constructed, and whether lifting the ban encouraged additional domestic production.

"The analysis indicates that the efficiency gains (real resource savings) from lifting the export ban would be \$2 - \$8 billion (even if no additional production is brought on by lifting the ban). If lifting the ban also were to cause a production response of 1.0 MMB/D by 1990, the efficiency gains would increase by at least \$2 billion," the report says.

"In addition, a significant production increase would restrain future OPEC price increases. The world price benefits to the U. S. of a 1.0 MMB/D increase for 1990 would save the U. S. \$4 - \$8 billion. As a result, with a significant production response, the increase in total benefits from lifting the ban would be \$8 - \$18 billion."

Alaska officials have maintained that the export ban significantly discourages additional North Slope production from known reservoirs and reduces the incentive to explore for new fields.

Lifting the ban would have the following effects, the study said:

-- North Slope producers would obtain higher after-tax profits on the sale of their crude;

-- The State of Alaska would obtain higher royalties, severance taxes and income taxes;

-- The federal government would obtain more income taxes and would obtain an import fee on every barrel imported to replace the North Slope crude shipped to Japan;

-- Foreign ship-owners would receive additional income for the transport of crude between Japan and the U. S. and between the Persian Gulf and the U. S.;

-- Domestic ship and pipeline owners would receive less income for the transport of crudes.

CONGRESSIONAL COMMITTEE ISSUES WEST COAST OIL SURPLUS REPORT

A recent report by the House Interior Committee indicates that lifting the ban on the export of Alaska oil is not high on Congress' list of ways to solve the West Coast oil surplus.

The committee report, prepared by Interior's Subcommittee on Special Investigations, urges expeditious construction of one of the overland pipelines proposed to ship Alaska North Slope oil from the West Coast to inland states. If none of the proposed projects has gotten beyond the planning stages by January, 1979, Congress should consider legislation to expedite construction, the report says.

The report also recommends that Congress give further consideration to the proposed Trans-Guatemala pipeline, which it calls "a viable proposal worthy of close attention in the months ahead."

The report labels exports or exchanges with foreign nations a "short-term" solution, along with shipment through the Panama Canal and limiting ANS production to the amount that can be consumed on the West Coast. The subcommittee said shutting-in ANS production would have to be "emergency in nature," and found no arguments to support this short-term solution.

As far as exports or exchanges, the subcommittee did not support or oppose them but said it found no reason to believe they would be allowed in the near future.

While the majority subcommittee report merely listed the pros and cons of allowing exports, a minority report strongly opposed them.

"We believe a temporary export or exchange of Alaska North Slope crude oil with foreign nations would be unwise at this time and most unwanted by the American people," the minority report said. "How can we speak of exporting our great domestic supplies at a time when our oil imports grow day by day?...Let us consider ways to move the Alaska oil within our borders, not ways to move it out."

The minority noted that even temporary exports "would cause irreparable harm to the solvency of the U. S. Panama Canal Company," which American taxpayers have underwritten through this century under the recent canal treaties. "Unless we are now ready to cover multi-million dollar deficits on an annual basis when the canal loses the keystone to its solvency--Alaska oil transport--we should disapprove the temporary export of Alaska North Slope crude oil," said the minority report, which was signed by Rep. Don H. Clausen of California, the subcommittee's ranking minority member.

The majority report listed five proposed pipelines and retrofitting of West Coast refineries as "long-term" solutions to the West Coast surplus. The report noted that all the proposals will require a construction period of at least two years from initial groundbreaking, and that environmental considerations will delay their operation even further into the 1980s.

Two pipelines no longer under consideration--Trans-Mountain and Kitimat--are "victims of this nation's and Canada's codified concern for its environment," the report said. The Sohio pipeline between California and Texas "continues to encounter enormous State (of California) environmental protection obligation requirements. Whether or not it will ever be approved for construction is anybody's guess at this time," the report said.

The Northern Tier proposal, which would extend 1,550 miles across Washington, Idaho, Montana, North Dakota and Minnesota, still lacks a final Environmental Impact Statement and "is so far away from completion that its viability may well depend on the success or failure of the other proposals," the report said.

SOHIO PIPELINE MOVES ONE STEP CLOSER

Voters in Long Beach, California, overwhelmingly approved a proposed oil terminal in the November elections, but three more obstacles to construction of the Sohio pipeline still remain.

The oil terminal referendum, approved by a vote of 61 percent to 39 percent, authorizes city and port of Long Beach officials to grant permits for Sohio to build a terminal to receive North Slope crude for shipment by pipeline to Midland, Texas, and the Midwest. Sohio reportedly spent $750,000 in its campaign to gain approval for the terminal, which was opposed by environmentalists.

The 1,000-mile pipeline would be able to carry 500,000 barrels of oil a day. About 800 miles of existing pipeline would be used in the project, and about 225 miles of new pipeline would be constructed. Construction of the oil terminal and new pipeline sections is expected to take about two years, once final government approvals are granted.

The company says it still must get favorable decisions on three matters before construction can begin:

-- The South Coast Air Quality Management District must approve Sohio's plan for offsetting air pollution created by the terminal.

-- Sohio is asking the California Coastal Zone Commission to amend the project's coastal zone permit and allow construction of oil storage tanks at pierside. The commission already has rejected this request, but Sohio plans to ask again.

-- The California State Supreme Court must decide whether the project's environmental impact report is adequate.

The Department of Energy, meanwhile, announced it has postponed construction of a 167-mile, government-owned crude oil pipeline between the Elk Hills naval petroleum reserve and the proposed Sohio pipeline system. DOE, citing uncertainties in Sohio's construction schedule, said no major expenditures will be made on the project during the next two years.

PRUDHOE ROYALTY GAS SALE STILL IN DOUBT

Natural Resources Commissioner Robert LeResche says the administration has not yet decided whether it will go forward with a Prudhoe Bay royalty gas sale next spring.

LeResche said he thinks a sale at this time would be "terrifically premature," considering the uncertainties surrounding the gas pipeline project, but he wants to discuss the matter with legislators and other state officials before a final decision is made. He recently asked the attorney general's office to draw up a draft contract for the sale.

The administration is under increasing pressure to sell the royalty gas and gas liquids this spring, particularly from people in Fairbanks.

A delegation from Fairbanks, led by Borough Mayor John Carlson, met with Hammond in Juneau recently to urge him to submit a contract for approval during the next legislative session.

LeResche angered a number of people in Fairbanks when he was unable to attend a borough-sponsored petrochemical seminar November 28. LeResche said the press of d2 business and attempts to keep President Carter from withdrawing lands under the Antiquities Act prevented his attendance.

"To put it mildly, the mood was definitely hostile," Andy Warwick, a member of the Royalty Oil and Gas Development Advisory Board, told the All-Alaska Weekly. Warwick also complained that LeResche had not called a meeting of the royalty board since May 19. According to press reports, some Fairbanksans fear that unless action is taken quickly, the state will lose out on petrochemical development by default.

The Department of Natural Resources last summer circulated a "general notice and solicitation" to 500 firms announcing that it intended to sell the Prudhoe royalty gas and gas liquids, with the sale tentatively scheduled to take place in March.

The draft contract prepared for LeResche would sell 80 percent of the Prudhoe Bay royalty gas for 20 years. All gas sold under the contract "shall be either processed or consumed within the boundaries of the State of Alaska," the draft contract says. "Buyer shall construct and operate, or cause to be constructed and operated, a facility for the in-state processing of the gas sold under this agreement."

The price for the gas would be at least the amount the state would have received by taking the gas in-value, and potential purchasers presumably would bid a variable number of cents above the in-value floor, the draft contract indicates. In addition, the contract says, if the federal government allows the costs of conditioning the gas to be added to the maximum ceiling price in the Natural Gas Policy Act, the price the royalty buyer pays will be increased by the amount of costs allowed.

LeResche said the legislature would be asked to approve the structure and terms of the contract before bidding takes place.

Don Wold, executive director of the state's Royalty Oil and Gas Development Advisory Board, said he agrees with LeResche that there is no big rush to sell the gas this year. "Whether we sell it this year or next is not important," Wold said.

Wold expressed concern, however, about the design of the North Slope conditioning plant set out in a study by the Ralph M. Parsons Co. The study was prepared for seven North Slope oil producers and 11 pipeline companies.

Wold said the conditioning facilities currently contemplated would use a large percentage of the gas liquids as field fuel rather than as exported products. If most of the liquids are used as fuel on the North Slope, they will not be available as feedstock for in-state petrochemical manufacturing.

"If you wanted a petrochemical industry in Alaska, you wouldn't select this design for the conditioning plant," Wold said. "The producers are flexible; they aren't locked in (to this design). But obviously they don't believe that petrochemicals are viable in Alaska, and since they don't believe it, it's an easier, simplier operation for them to burn the liquids on the North Slope....If someone were to convince the producers that petrochemicals are going to happen, I've found no evidence that they wouldn't be willing to change and produce the liquids."

In an October 24 memo to LeResche, Wold spelled out a number of actions that would help retain the option of liquids production, including:

-- Obtain an improved estimate of constructing an 18-inch liquids pipeline from Fairbanks to tidewater;

-- Request that Northwest Alaskan, in cooperation with a state consultant, estimate the cost of constructing an 18-inch liquids line from Prudhoe to Fairbanks;

-- Request that ARCO (coordinator of the Parsons study) estimate what changes would be required in the conditioning facilities should it become feasible to recover the maximum amount of liquids;

-- Request that Northwest estimate the economic impact on the gas pipeline should the liquids be removed;

-- Ask FERC what its position would be if the liquids were removed from the pipeline and retained in Alaska; and

-- Ask the Alaska Railroad to estimate the cost of moving the liquids from Fairbanks by rail.

Wold said he expects a preliminary report by the end of the year from Bonner & Moore Associates, which is under contract with the Department of Natural Resources to help the state promote development of a petrochemical industry. The report will address the economics of in-state petrochemical manufacturing. "With the numbers we have now," Wold said, "it looks very marginal."

PACIFIC ALASKA LNG PROJECT PROCEEDS; ALASKA'S RIGHT TO WITHDRAW COOK INLET ROYALTY GAS UNCERTAIN

Alaska would have difficulty withdrawing its Cook Inlet royalty gas for in-state use from fields supplying the Pacific Alaska LNG project if the Federal Energy Regulatory Commission follows the recommendations of its staff.

In a "reply brief" dated November 21, the FERC staff recommended that the commission not allow Alaska to switch from in-value to in-kind taking for royalties initially committed to the LNG project without first getting abandonment authority from FERC.

"Alaska has made absolutely no showing of in-state need for this gas in even the remote future. The condition suggested (by Alaska) amounts to a pre-granted abandonment of unknown quantities of gas, at unknown times, for unknown duration and for unknown purposes," the FERC staff said.

One of Alaska's main concerns in the federal regulatory proceedings on the proposed Cook Inlet LNG project has been to assure that it will be able to withdraw royalty gas for in-state use should the need arise in the future. Alaska has asked that FERC guarantee this right as a condition to its certification of the LNG project.

Alaska's ability to withdraw its Prudhoe Bay royalty gas from the proposed Alaska Highway gas pipeline is protected by Section 13(b) of the Alaska Natural Gas Transportation Act of 1976. The act states, "The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and, to the extent its contracts for the sale of royalty so provide, to withdraw such gas from the interstate market for use within Alaska..."

The Pacific Alaska LNG project, which has been pending before federal regulators since 1974, would liquify gas from 19 Cook Inlet fields at a Nikiski plant for export to Southern California. About 400 million cubic feet of gas a day would be transported in LNG vessels to a terminal at Point Conception, California. LNG (Liquified Natural Gas) is naturally occurring methane transported in liquid form by tanker.

In a brief filed November 7, the state reiterated its position that it is willing to allow its gas to be exported to serve the needs of Lower 48 users until "a specific feasible use" develops in Alaska. Alaska insisted that its "right to take the royalty in kind is paramount to the producers' right to sell 100 percent of production to Pacific Alaska LNG."

Under the old Natural Gas Act, once gas is "dedicated" to interstate commerce, "abandonment" permission must be obtained from FERC before the gas can be withdrawn from interstate commerce. Alaska argued in its brief that the Natural Gas Policy Act of 1978, rather than the old Natural Gas Act, governs disposition of the Cook Inlet royalty gas.

Under the new Natural Gas Policy Act, Alaska argued, FERC no longer has authority to require abandonment if the gas was not committed or dedicated to interstate commerce on the date the new act took effect. The Cook Inlet gas in question has not been dedicated to interstate commerce, Alaska said, since no certificates have been issued and no gas has flowed in interstate commerce.

"The Commission is without jurisdiction to order the State of Alaska, at an appropriate time in the future, not to exercise its royalty rights vis-a-vis the producers and withdraw future supplies of Cook Inlet royalty gas from the interstate market without obtaining abandonment authority," the state said.

Alaska said FERC should certify the LNG project, as well as protecting the state's right to withdraw its royalty.

"Respecting Alaska's royalty rights will not endanger this project or adversely affect the interests of consumers. It will tend to enlarge the supply of gas for this project and make available to the Lower 48 States present and future Alaskan reserves from Cook Inlet. The public interest would be well served by certifying this project with full confirmation of Alaska's royalty rights," Alaska said.

The FERC staff, however, said Alaska's interpretation of the laws is erroneous, and concluded that Cook Inlet gas now under contract to Pac Alaska already has been "committed or dedicated" to interstate commerce. Since the gas already is committed, FERC retains its authority under the Natural Gas Act to require that the gas supply upon which the project relies is firmly committed to it, the FERC staff said.

Also, the FERC staff said, Alaska has failed to show that protection of its royalty rights "is in the public convenience and necessity." Alaska failed to show, despite a specific request from Staff Counsel in October, 1977, exactly how much natural gas it will need for its own use from Cook Inlet reserves, whether alternate fuels such as coal or electricity would satisfy those energy needs, and data on needs for in-state markets. "Mr. (Fred) Boness (deputy commissioner of Natural Resources), Alaska's only witness, failed to give even the most general projection of any in-state need at all during the life of the project," the FERC staff said.

The issue of state royalty rights is closely related to another issue--whether there is adequate gas in Cook Inlet to support the project. In order to supply 400 million cubic feet of gas a day to California for 20 years, Pac Alaska will have to obtain contracts for about 3.1 trillion cubic feet of gas. At present, the project has only about 800 billion cubic feet (including state royalties) under contract, or less than one-third of the amount needed.

The FERC staff recommended that the project's certificate not become final until 2.6 trillion cubic feet of gas has been dedicated to the project, and suggested that Pac Alaska be given one year to secure contracts for the necessary reserves. Pac Alaska should not be able to count Alaska's royalty share in the 2.6 Tcf unless it can show that Alaska has elected to receive its royalty interest in-value for the life of the gas supply contracts, the FERC staff recommended.

Pac Alaska's parent companies, which also have exploration subsidiaries, already have spent about $35 million looking for gas in Cook Inlet, and they have put up an additional $20 to $30 million in loans to producers for drilling in known fields. The companies plan to spend another $20 to $30 million on exploration during the next three years.

In response to charges that Pac Alaska is buying up all the known gas reserves in Cook Inlet, gas that Anchorage may need in the future, Pac Alaska spokesman Bill Cole responded: "We are putting up money to drill where there's never been any incentive to drill before. We are making the pie bigger. Except for Lower Cook Inlet, there was no exploratory drilling of any magnitude going on in Cook Inlet until we came along and put up real big money."

Cole also points out that Pac Alaska has been unable to get contracts for most of the proven uncommitted reserves left in the Inlet, and that most of the gas under contract to the project was found with Pac Alaska's money. He said he remains optimistic that Pac Alaska will find the gas it needs, although not within the one-year time frame suggested by FERC staff.

Final FERC hearings on a number of issues in the case are scheduled for early December, and a FERC administrative law judge is expected to make a recommendation on whether to certify the project next spring or summer. A decision by the full commission is not expected before late 1979, and that decision could be appealed to the federal courts.

The Pac Alaska project is sponsored jointly by subsidiaries of Pacific Lighting Corp. and Pacific Gas & Electric Co. (PG&E). The two parent companies also jointly sponsor the Pacific Indonesian project, which will import LNG from Indonesia to the same Point Conception terminal proposed for the Pac Alaska project. The economic viability of the Pac Alaska project depends on approval of the Pacific Indonesia project, a spokesman for Pac Alaska said.

In final Environmental Impact Statements issued recently for the two projects, the FERC staff concluded that environmental impact associated with the Alaska project would be limited. The LNG terminal at Nikiski would not have a significant environmental impact, and the risk associated with operation of the LNG ships is acceptable, the FERC staff said.

With respect to the California terminal, however, the FERC staff said Point Conception should be rejected primarily because it is near an active earthquake fault. The FERC environmental staff said Oxnard is the superior location for an LNG terminal facility, taking into account all environmental factors, including public safety.

Western LNG Terminal Associates (another joint subsidiary of Pacific Lighting and PG&E) originally proposed to build separate terminals at Oxnard for the Indonesian imports and in Los Angeles Harbor for the Cook Inlet gas. However, both sites were eliminated as possible terminal locations by California legislation requiring that the state's first LNG terminal be constructed in a sparsely populated area. In light of this legislation, Western Terminal asked the California Public Utilities Commission to approve a single terminal near Point Conception to handle gas from both Indonesia and Alaska. The California PUC has conditionally approved the Point Conception site, pending the outcome of future hearings on safety and environmental issues.

A major issue in the controversy over where to put the LNG terminal is whether California can assert jurisdiction to select and approve it. The FERC staff has argued that the California legislation intrudes into an area Congress has entrusted to federal regulation, thereby preempting state regulation. It is unclear how this matter will be resolved, short of litigation.

To complicate things even more, the federal Economic Regulatory Administration has jurisdiction over some aspects of LNG imports and exports, such as security of supply and effect on U.S. balance of payments, and must also approve the Pacific Indonesia project.

ALPETCO SELECTS VALDEZ FOR FACILITY SITE

Valdez, the city selected by Alpetco for its planned refinery and petrochemical complex, has adopted an ordinance that will require tankers arriving at the trans-Alaska oil pipeline terminal to burn low-sulfur fuel while in port.

The low-sulfur fuel ordinance, which was adopted 5-1 by the Valdez City Council December 5, requires tankers of more than 15,000 tons to use fuel with a sulfur content of less than .7 percent while pumping ballast tanks within the Valdez city limits. The ordinance takes effect January 1, 1982.

Valdez Mayor L. F. MacDonald said the new ordinance will be sufficient to offset pollution created by Alpetco's refinery and petrochemical facility. Without the ordinance or some other mitigating measure, Valdez likely would have violated federal air quality standards once the new refinery began operation.

Alpetco officials said the decision to select Valdez over Kenai for the refinery site was based primarily on economic factors, specifically a $20 to $30 million annual saving in shipping costs. Since the site about five miles east of Valdez is near the oil pipeline terminal, the company won't have to pay the extra cost of shipping the oil to Kenai.

Valdez has offered Alpetco essentially free city land for the plant site, and the city plans to issue tax-exempt Industrial Development Bonds to help finance docks, support facilities and pollution control devices.

The legislature last session awarded Alpetco a 27-year contract to purchase 85 percent of the Prudhoe Bay royalty oil. Under terms of the contract, Alpetco will become eligible to begin purchasing the oil in about a year and a half if it has obtained financing commitments for at least $1.5 billion and actually spent $100 million on the project.

A spokesman for the Department of Natural Resources said Commissioner LeResche expects to make a decision approving or disapproving the Valdez site by mid-January. A public hearing will be held in Valdez in early or mid-January.

Construction of the facility is not expected to begin before late 1980.

NATIVES PROTEST EXXON DRILLING AT DUCK ISLAND

Two native villages and the City of Barrow have filed suit in state and federal court in an attempt to stop exploratory drilling from a man-made gravel island in the mouth of the Sagavanirktok River, about 12 miles east of Prudhoe Bay.

If successful, the suits would have a chilling effect on oil and gas exploration and development all over Alaska, state officials say.

The state suit charges that the Department of Natural Resources committed procedural errors in approving the Duck Island Unit Agreement and a drilling permit. State Superior Court Judge Victor Carlson has denied the Natives an injunction in the case, thereby allowing drilling to continue until the case is decided.

"The uncertainty which would attach as a result of injunctive relief will effectively halt oil development in the State of Alaska," the state said in a brief opposing the injunction. A ruling for the plaintiffs "will result in a long-lasting and severe impact on Alaska's already weakened economy."

The leases in question were sold by the state in 1969 and bought by nine oil companies for more than $20 million. The companies formed the Duck Island Unit, which was approved by the Department of Natural Resources in August of this year, and designated Exxon as unit operator. The leases would have expired in September of 1979 unless oil drilling or production activities had begun.

"At issue here is our permitting procedure, and the ability of a leaseholder to exercise the rights he paid for," said Tom Cook, director of the Division of Minerals and Energy Management. "I'm worried about what this case does to future leases. If our permitting procedures and law can be successfully challenged, and multi-million dollar drilling operations halted, it's obvious what this does to the value of future leases."

Cook said unitization is an environmentally sound practice, since it allows one well to satisfy the drilling commitment. The alternative to unitization would be for each of the nine companies to proceed separately with drilling. "Unitization minimizes the environmental impact and allows the companies to assess the area without extensive drilling," Cook said.

The villages of Kaktovik and Nuiqsut, the City of Barrow, and two Native subsistence hunters charged in the suit that Exxon's activities are having an injurious effect on the bowhead whales and other marine mammals in the area. The Natives depend on the whales for food and "consider them vital to the continuation of their culture."

Donald Clocksin, the Alaska Legal Services attorney representing the Natives, told the Associated Press the suits represent "the opening shot in a major battle" against the Beaufort Sea lease sale scheduled for December, 1979.

State officials disagree with the Natives' contention that unitization amounts to a sale or disposal of interest in state lands and therefore requires public notice and other procedures.

Natural Resources Commissioner Robert LeResche said the procedural charges in the state suit are "frivolous," and the Natives "are just looking for technical ways to stop the drilling."

Some state officials believe, however, the Natives may have a much stronger case in the federal suit filed in U. S. District court against the U. S. Army Corps of Engineers and Exxon.

Federal District Court Judge James von der Heydt denied the Natives' motion for a temporary restraining order November 16. A hearing on their motion for a preliminary injunction was held December 7, but the judge has not yet ruled.

Ernst Mueller, commissioner of the Department of Environmental Conservation, has filed an affidavit supporting the Natives' charges that the Corps of Engineers violated federal law by issuing permits for Exxon to build the gravel island as a base for offshore drilling.

The federal Clean Water Act requires that Exxon present the Corps of Engineers with certification that its planned activity meets state water quality standards. Without the state certification, which was not issued in this case, the Corps of Engineers cannot legally issue permits to build such an offshore island, Mueller said in his affidavit.

Mueller's affidavit indicates the Corps of Engineers habitually ignores requirements for the state to certify proposed projects affecting water quality in Alaska.

INTERIOR DEPARTMENT CONSIDERS P.L.O. 82

The Interior Department is expected to decide in the near future whether the federal government will attempt to reclaim a large chunk of arctic Alaska under Public Land Order 82.

P.L.O. 82 is an executive World War II land withdrawal that reserved for military purposes all submerged lands north of the Brooks Range crest, an area that includes about 40 percent of the oil and gas at Prudhoe Bay and the entire arctic coastline out to the three-mile limit.

Although the land order was revoked in 1960, Interior has argued the state does not have title to the lands since the order was in effect at the time of statehood.

Tom Cook, director of the Division of Minerals and Energy Management, said Interior has written an opinion adverse to the state but was persuaded by state officials to reconsider. The opinion, Cook said, would have asserted that the federal government had title to all lands reserved under P.L.O. 82.

Deputy Natural Resources Commissioner Fred Boness, who participated in talks with Interior officials in early November, said, "The meetings didn't go well. I don't know what's going to happen. We have to be prepared to deal with any eventuality. I don't think the decision is going to be favorable."

Natural Resources Commissioner Robert LeResche said uncertainty over P.L.O. 82 is having an adverse effect on gas sales negotiations between North Slope producers and the pipeline companies building the Alaska Highway gas line. "The firms are not selling the gas; they can't as long as there's any question about who owns it," LeResche said.

P.L.O. 82 also could disrupt plans for the joint state-federal Beaufort Sea lease sale scheduled for December of 1979.

"The spector of P.L.O. 82 creates a lot of uncertainty," said Cook. "The companies will be reluctant to bid if they think title to the land is in doubt. Who wants to buy litigation? I don't think we should hold the (Beaufort) sale if this is not resolved."

FEDERAL GOVERNMENT REVISES OCS LEASING SCHEDULE

Eleven of 22 areas proposed for inclusion in the federal government's new OCS leasing schedule for 1980-85 are in Alaska.

The federal government is in the process of preparing a leasing plan for the next five years under recent amendments to the OCS Lands Act, and is soliciting comments from affected states. The state's response on the preliminary proposal will be completed in early December, said Craig Lindh of the Division of Policy Development and Planning.

Areas in Alaska proposed for sale include Cook Inlet, Gulf of Alaska, Kodiak, Southern Aleutian Shelf, Bristol Basin, St. George Basin, Navarin Basin, Norton Basin, Hope Basin, Chukchi Sea and Beaufort Sea. Dates for the proposed sales have not yet been published.

The Secretary of the Interior won't approve the final plan until January, 1980. During the next year, Interior will hear public comment and make revisions in the plan, which will be submitted to President Carter and Congress next November.

A decision to proceed with any specific sale on the schedule will be made only after all requirements of the OCS Lands Act, the National Environmental Policy Act and other statutes are met.

Interior is proceeding with plans to sell leases in the eastern portion of the Gulf of Alaska in June, 1980. In late October, Interior announced selection of almost two million acres for environmental study and possible inclusion in the sale.

This would be the second OCS sale in the Gulf of Alaska. The first, which was in April, 1976, and brought bids of $560 million for about 410,000 acres, was recently declared valid by D. C. Circuit Court of Appeals in response to environmental challenges raised by the state. Alaska challenged the sale on grounds it violated the National Environmental Policy Act.

The state administration, meanwhile, is preparing its own five-year leasing plan under terms of a new oil and gas leasing law adopted by the legislature last session (HB 854).

The new law requires that the Commissioner of Natural Resources submit a plan to the legislature by the 15th day of the next session covering all areas to be leased in 1979 through 1983.

Tom Cook, director of the Division of Minerals and Energy Management, said he will recommend two changes in the 1979 schedule announced by Gov. Hammond last March. Cook said he will recommend that the Copper River Valley sale be deleted, since the state has little land available for lease in the area and industry has shown little interest. He said he will recommend that the Susitna Valley sale be postponed until after the December Beaufort sale to allow his staff adequate time for preparation.

"Susitna would be a 'limited acreage' sale, which could be held without extensive pre-sale procedures, studies, notice and opportunity for public comment," Cook said. "However, it should be obvious after Point Thomson (which was canceled by Hammond in September) and the Duck Island suit that it's unwise to proceed on that basis."

STATE FAVORS JOINT BIDDING FOR BEAUFORT SALE

The state will urge the Interior Department to waive restrictions for the 1979 Beaufort Sea lease sale that prohibit major oil companies from submitting joint bids.

"In the case of the Beaufort Sea, we'd like to see the secretary waive restrictions on joint bidding," said Tom Cook, director of the Division of Minerals and Energy Management. "We believe this would enhance the number of offers, the amounts of the offers and minimize risk among the parties. This is a high-cost, high-risk area and it cannot be as effectively developed or explored if joint bids are prohibited," Cook said.

OCS Lands Act Amendments of 1978 specify that the Interior Secretary may waive the joint bidding ban if he determines that exploration and development will have an extremely high cost and will not occur unless an exemption is granted.

At the request of Chevron USA, the Interior Department scheduled hearings on the matter December 5 in Anchorage and December 8 in Washington, D.C.

ECONOMISTS SEE "HARD LANDING," FAVOR DIRECT DISTRIBUTION OF OIL WEALTH

Many of Alaska's leading economists think the state will face a fiscal "hard landing" sometime in the next 10 to 15 years.

Thirty of the state's leading economic model builders and users, who attended a Symposium on Economic Model Building in Alaska October 21 and 22 in Anchorage, also generally agreed it would be desirable for the state to distribute some of its oil wealth directly to its citizens.

Sponsored by the Legislative Affairs Agency, and funded out of money allocated to gas pipeline financing studies, the symposium provided a look at the strengths and weaknesses of the models in operation in the state today.

The smaller revenue and expenditure forecast models and the petroleum revenue tax model, as Dave Knudsen remarked, were "not built to make predictions." They were, however, all considered to be useful analytical tools. The larger models include those of the Department of Labor, the Department of Commerce and Economic Development (CED), and the MAP model of the University of Alaska's Institute of Social and Economic Research. "Use of these models needs to be carefully tailored to their capabilities," commented David Reaume of CED, particularly when one is looking more than two years into the future.

The only large, long-term policy testing model available in Alaska, the MAP model, was recognized to have both strengths and weaknesses. On the plus side, this comprehensive regional model can in theory answer many of Alaska's major policy questions. Furthermore, its operators will change parts of the model that caused problems in the past, such as its rules for internally generating state government spending rates. The symposium generally agreed that changes of this kind, together with a greater anticipation of user interests, would eliminate the confusion that developed last year when the MAP model was employed to analyze the ALPETCO proposal. Almost all conference participants agreed that an investigation of the impacts of gas line construction along the lines of the ALPETCO study is necessary and desirable.

A discussion led by Arlon Tussing, Lee Gorsuch, and Gregg Erickson reviewed future modeling needs. Impacts from construction of a gas pipeline, use of the Permanent Fund to develop renewable resources, and use of the capital account to pay cash for new buildings were identified as topics needing additional analysis.

On the fiscal question there was complete agreement, based on quite independent analysis, that the state likely will face a "hard landing" when the Prudhoe Bay oil finally stops flowing. More stringent fiscal control will be needed for a soft landing in the 1990s. Several participants noted that there appear to be few economic alternatives to generate the magnitude of revenue needed to cushion the landing.

The group also discussed methods to reduce the annual spending pressure placed on the legislature, including implementation of constitutionally imposed spending ceilings and distribution plans such as Alaska Inc.

The economists agreed that some form of distribution plan, in spite of major "leakages" that federal taxes would impose, would maximize benefits from the oil wealth and might be the only successful way to curb state spending growth. The degree of unanimity on this was unexpected. Although several economists said vested interests of the present government fiscal structure eventually would defeat the plan, almost all supported it in concept.

HAMMOND WILL ASK FOR SUSITNA APPROPRIATION

In an attempt to keep the controversial Susitna hydroelectric project on track, Gov. Jay Hammond announced recently he will seek a $7 million legislative appropriation to provide guarantees for studies on the project.

The massive project, promoted as a way to assure adequate electricity for Alaska's "rail belt," would involve construction of two dams on the Susitna River and 365 miles of transmission line. The project is now estimated to cost $2.7 billion in today's dollars, according to Eric Yould, executive director of the Alaska Power Authority.

The project will require a four-year "Phase I" study, which will examine environmental, economic, social and engineering concerns. Phase I studies, estimated to cost at least $25 million, will be conducted by the U. S. Army Corps of Engineers.

Legislation that would have provided federal guarantees for the Phase I studies died in the waning hours of the 95th Congress. It has been widely reported that the House of Representatives failed to approve the measure in retaliation against Sen. Mike Gravel's action killing the d2 lands legislation, although Gravel aide Jerry Gauche says the House action had nothing to do with d2.

The federal legislation would have amended the Alaska Hydroelectric Power Development Act of 1976, and would have provided that the federal government reimburse the Alaska Power Authority for the cost of Phase I studies if the project turned out to be infeasible.

The state legislature last session approved a resolution (Legislative Resolve No. 45) authorizing the Alaska Power Authority to fund the Phase I studies through the sale of revenue bonds, but this authorization was made contingent on passage of the federal legislation.

The $7 million appropriation sought by Hammond would provide guarantees for the sale of revenue bonds sufficient to cover the first year of the four-year studies. Yould said recent estimates indicate the first year of studies will cost $8.2 million, and he will recommend that the governor request the higher amount.

Gauche said Gravel will try again to get Congress to approve the legislation providing federal guarantees early in the next session.

"There is a certain risk to the state if this appropriation is approved," Yould said. "If Gravel never gets his legislation, the state will be out $8.2 million and will have to come up with additional money to complete the studies....However, Gravel has told me he thinks he can get this legislation early in the next session. I wouldn't be suggesting that the state make this appropriation to the Power Authority if I didn't think he could produce."

Hammond said he would request the state guarantees because "I believe it important to keep this feasibility study on schedule to avoid delays and increased construction costs. We need this information to determine whether the Devil Canyon project is environmentally and economically feasible. We want our decision based on fact, not guesses."

Even if the legislature or the Congress provides guarantees for sale of the revenue bonds, two other hurdles must be cleared before the Phase I studies can begin.

First, the U. S. Army Corps of Engineers must receive permission to participate in the study from the Office of the Chief of Engineers and the Office of Management and Budget in Washington. "OMB is standing in the way of Susitna right now," Yould said. "They have not authorized any new (water resource project) starts since Carter took office."

Second, access to the Susitna land to perform the studies will require permits from the Bureau of Land Management and agreements granting access from the Cook Inlet region and village corporations.

STATE ENERGY POLICY COMMITTEE ADOPTS POLICY GUIDELINES; DEVELOPS STRATEGY FOR IMPLEMENTATION

The state should study the costs, risks and benefits of contracting for exploratory drilling for oil and gas and obtaining additional geological and geophysical data, the State Energy Policy Committee has recommended.

The committee, meeting in Juneau December 6, decided to seek funds from the next legislature to study whether the state should invest money to obtain more extensive information about the resource potential of lands before leasing them for resource development. The study would be conducted jointly with the Department of Natural Resources.

The committee, chaired by Rep. Bill Miles, includes members of the legislature, administration and public.

At an Anchorage meeting November 29, the committee approved "policy guidelines" for the development and management of the state's energy resources, energy conservation and planning for in-state power development. Policy guidelines on the disposition of state royalties, which closely parallel the present policies of the Royalty Oil and Gas Development Advisory Board, were adopted by the committee at the December 6 meeting.

With general energy policies adopted, the committee then considered and adopted a number of ways to implement them, including:

-- In order to "encourage the development of economically viable renewable energy resources for in-state use," the committee decided to seek a change in Alaska law giving tax breaks (expensing of intangible drilling expenses and cost depletion) for geothermal wells. Congress recently adopted such a change in federal law in the Energy Tax Act of 1978.

-- In an attempt to "insure the orderly and timely development of energy resources, taking into consideration resource marketability," the committee decided to study the possibility of enacting a uranium leasing law.

-- In order to "insure a fair return to the people of the State for conveyance of state-owned energy resources," the committee will recommend an increase in coal royalties.

-- In order to "protect the environment when this is consistent with other provisions of the State Energy Policy," the committee plans to oversee development of state coal mining regulations under the federal Surface Mining Control and Reclamation Act of 1977.

The committee also wants to assure coordination of the state's environmental impact assessment process, to avoid overlap between state and federal agencies, for all energy projects that significantly affect the human environment.

-- In order to "encourage and facilitate the implementation of energy conservation measures, for all in-state energy use," the committee will look into the fiscal impact of increasing state tax credit amounts and limits for residential fuel conservation credits. State law currently allows a tax credit of 10 percent, with a $200 limit, for insulating homes and installing alternate sources of power generation, such as wind, tidal, solar or geothermal. The new federal Energy Tax Act provides a 15 percent credit, with a $2,000 limit, for the costs of installing alternate power sources in homes.

The committee also wants to expand the authority of the Alternate Power Resource Revolving Loan Fund to allow loans for capital expenditures for energy conservation improvements.

The committee also suggested that state funds be used to supplement federal weatherization programs, if additional money is needed for administrative and labor costs.

The committee decided that statewide lighting and thermal efficiency standards should be adopted, with local communities having enforcement responsibility.

-- In order to "encourage the optimal use of exhaust heat," the committee wants to require, as a condition of using state royalties, that any baseload plant be a combined cycle unit, using waste heat from a gas or coal turbine to run a steam plant. The committee will look into requiring the efficient use of waste heat for any large industrial facility or pipeline.

-- In order to "assure coordination of State and Federal responsibility in planning for in-state energy needs and the development of in-state energy projects, and to avoid duplicative and overlapping effort," the committee will seek legislation to require the Division of Energy and Power Development "to give equal consideration to all types of power generation, which are technologically feasible to promotion of efficient fuel and facility use, consistent with energy conservation goals, and achievement of the lowest reasonable costs" in developing a long-range plan for the state.

-- In order to "encourage the availability of energy to all people of the state at the lowest possible rates, consistent with good management practices," a liaison group chaired by Rep. Leo Rhode recommended that the Reserve for Energy Facilities Development account be used by the Alaska Power Authority to help finance construction of smaller hydroelectric projects.

The reserve acount, established last session by Chapter 168 SLA 1978, will receive 5 percent of the state's mineral lease bonuses, rentals and royalties, and will be subject to annual appropriation of the legislature.

Suggestions for implementing policies on royalty disposition will be considered at the committee's next meeting, which has not yet been scheduled. The committee's final report is due by January 31, 1979.

ALASKA PIPELINE COMMISSION CONSIDERS "ALLOCATION OF SERVICE" FOR TAPS

The Alaska Pipeline Commission (APC) took testimony at a November 28 hearing in Fairbanks on whether four of the eight Trans-Alaska Pipeline carriers should be allowed to limit the amount of oil they carry for North Pole Refinery.

Last summer, BP Pipelines, Mobil Alaska Pipeline Co., Phillips Alaska Pipeline Corp. and Amerada Hess Pipeline Corp. filed initial tariffs for intrastate oil shipment. Under these initial tariffs, North Pole Refinery would have been charged as if its oil had traveled all the way to Valdez, even though its oil comes out of the pipeline near Fairbanks. On September 20, the commission suspended these initial tariffs and set interim, distance-related rates (about 60 percent of the full tariff) for delivery at Fairbanks. The interim tariffs do not take effect until mid-December.

The commission earlier set permanent, distance-related tariffs to Fairbanks for the other four carriers--Sohio Pipe Line Co., Union Alaska Pipeline Co., Exxon Pipeline Co. and ARCO Pipe Line Co.

BP, Mobil, Phillips and Amerada Hess have until February 1 to let the commission know whether they want a full hearing on their intrastate tariffs, a regulatory process already completed for Sohio, Union, Exxon and ARCO.

The intrastate tariffs to Fairbanks vary from $3.63 for ARCO to $3.87 for Amerada Hess. The average to Fairbanks for all eight companies is about $3.71, while the average tariff to Valdez is about $6.20.

The initial intrastate tariffs filed by BP, Mobil, Phillips and Amerada Hess also included special rules that limited the amount of intrastate oil they would carry. Specifically, the special rules limited each carrier's intrastate obligation to the percentage of pipeline capacity owned by that carrier.

The APC suspended the special rules at the same time it suspended the initial tariffs, but set a public hearing on the propriety of the special rules for November 28. Post-hearing briefs will be accepted until late January, so the commission will not decide the issue until February, at the earliest.

Under state law, the APC can "allocate service" over the pipeline, or impose a scheme for distribution of intrastate shipments among carriers.

Under law TAPS is a "common carrier" pipeline and must accept for transportation oil "tendered" (offered for shipment) to it without discrimination. TAPS operates like eight separate pipelines, with each carrier controlling an amount of space in proportion to its ownership share. If more oil is offered to a carrier than it can accommodate, it will reduce the amount of each tender by an equal percentage. This is called "prorationing."

Some of the companies apparently want to limit the amount of intrastate oil they are required to carry for economic reasons, since they make less money when oil comes out at Fairbanks and their downstream portion of the pipeline is less than full. North Pole Refinery, the only intrastate takeoff along TAPS, ships about 25,000 barrels of oil a day, of which about half is returned to the pipeline after some processing.

Lloyd Pernela of Earth Resources Company of Alaska, which owns North Pole Refinery, said the company has been unable to get all its oil shipped because until recently only four of the carriers (Sohio, Union, Exxon and ARCO) accepted intrastate shipments, and some of North Pole's oil was bumped by prorationing. A complaint by North Pole in July led to the filing of the initial intrastate tariffs by the other four companies. North Pole was 5,000 barrels short several days in September, Pernela said, and is still falling short some days because the new, lower tariffs for BP, Mobil, Phillips and Amerada Hess do not take effect until mid-December.

"We hope the APC will throw out the special rules," Pernela said. "To deny us the ability to tender crude to common carriers is gross discrimination."

The APC staff, in a recent brief, recommended that "the special rules included in the tariffs of Mobil, BP, Phillips and Amerada Hess be rejected and that allocation of service among intrastate carriers not be ordered by the commission. In lieu of allocation and the special rules, it is the staff's recommendation that a coordinated tender schedule be established whereby each shipper is given an opportunity to receive regular information regarding transportation availability."

Jim Williams, executive director of the APC staff, said Earth Resources and the pipeline companies agreed at the Fairbanks hearing that they do not want the commission to allocate service.

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

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LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

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-- Compiled by Kay Brown, Policy Analyst --

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Oil Surplus

PROSPECTS IMPROVE FOR MEXICO-JAPAN-ALASKA OIL EXCHANGE

Mexican officials have "agreed in principle" on the terms of a contract to implement the proposed royalty oil exchange between Mexico, Japan and Alaska, Natural Resources Commissioner Robert LeResche says.

LeResche, who made a second trip to Mexico in late January to continue talks on the swap, said a formal contract won't be drawn up until President Carter approves the idea.

Although the White House has not yet agreed to put the swap on the agenda for discussion between President Carter and Mexican President Lopez Portillo when the two leaders meet in mid-February, LeResche said he is optimistic the matter will get attention. "We're pulling out all the stops to get it on the agenda," he said. "Portillo is going to request it; the governor is calling (Trade Ambassador Robert) Strauss and Carter personally."

The points agreed on by Mexico, LeResche said, include:

-- Alaska will deliver North Slope crude to the Pemex (the Mexican national oil company) account in Japan. Pemex will deliver Mexican crude to Alaska at Mexico's East Gulf Coast. Alaska intends to assign its rights and obligations of the contract to a third party--a major oil company or trading company.

-- The swap would not begin before June, 1979.

-- The volume will be 100,000 barrels per day.

-- Mexico will receive the "present prevailing price" for Mexican crude, recently raised to $14.10; the price term will be renegotiated every three months. LeResche said the state did not offer Mexico any price advantage for its participation. He said there are non-price advantages in the deal for Mexico, such as earlier trade and greater bargaining leverage with Japan.

-- Pemex will select the Japanese firm to participate in the swap.

-- The contract may be terminated at any time by the U.S. government if American petroleum supplies are interrupted or seriously threatened by world events, or if North Slope or Pemex production diminishes due to force majeure.

LeResche said he explained to the Mexicans that the deal is likely to face political opposition in the United States and "warned them not to get their hopes up falsely."

Obstacles still remain

Alaska officials would like to get Sohio as the state's middleman to be responsible for day-to-day operations such as arranging tankers and taking delivery. Sohio has not yet agreed to participate, although Sohio Chairman Alton Whitehouse, Jr., recently said he strongly favors the general idea of exporting North Slope crude. The administration has hired Stuart Myar, a former marketing vice president for Sohio, to assist in working out arrangements.

Alaska also will ask Sohio to share with the state some of the profits it will make if the deal is approved. As the company suffering most from the West Coast oil surplus and the only company unable to market the bulk of its North Slope oil on the West Coast, Sohio would benefit either from approval of the state royalty oil swap or from a general lifting of the export ban.

"We're going to ask them to absorb some of the costs (of arranging the royalty oil swap) or to give us a premium," LeResche said. "They're clearly worse off without the swap than they are in having the swap and sharing some of the benefits with us. Besides, as a good corporate citizen of Alaska, Sohio won't wish to be the one to kill this deal when it's so much to our benefit." LeResche said he would formally approach Sohio with the idea "as soon as we get firm numbers showing the tremendous profit they're going to make."

Lack of firm figures on several critical points (such as the value of North Slope oil in Japan) makes it impossible to precisely calculate at this point how much money will be saved in transportation costs. LeResche said the saving could be anywhere from 1¢ to $2. "We honestly don't know yet," he said, but "we've got people working on it."

Another potential problem is that all Mexican production already has been committed through 1979, LeResche said. However, there are several possible solutions -- some of Mexico's customers might not renew contracts; a "paper" arrangement could be worked out; Mexico might increase production; or the process of presidential and congressional approval combined with the requirement for six-month notice to producers before in-kind taking might delay the deal to the end of the year.

The biggest immediate obstacle is winning the endorsement of President Carter. "I won't be surprised if Carter does approve it, but I won't be surprised if he doesn't either. But we're getting more optimistic every day," LeResche said.

Governor Hammond, Attorney General Avrum Gross, LeResche, State Representative Bill Miles and legislative consultant Arlon Tussing met in Washington with Department of Energy and White House officials in mid-January and came back encouraged that the administration will support the proposal.

Even with Carter's support, the deal won't be assured until it has been approved by Congress.

An association representing U.S. maritime interests, who stand to lose business if Alaska oil is allowed to be exported in foreign tankers, reportedly has begun an intensive lobbying campaign against the proposal in Congress. "They apparently are quite alarmed about it," one Washington lobbyist said.

Odds Improving

Energy Secretary Schlesinger, in a recent appearance before the Senate Energy Committee, said he believes congressional opposition to the export of Alaska oil may be diminishing. "For the past several months, we have tried to soften congressional resistance to exports. The climate may be better now than 18 months ago," The Anchorage Times' Washington Bureau quoted the secretary as saying.

Senator J. Bennett Johnston, a democrat from Louisiana, told Schlesinger that when restrictions imposed by the Export Administration Act expire in June, "it would be in the national interest for the President to go ahead and allow Alaskan exports. After all, we're talking about our balance of payments."

Senator Henry Jackson of Washington, chairman of the Senate Energy Committee, called the West Coast oil surplus "terrible and outrageous."

"We have only begun to tap the vast energy resources of Alaska," Jackson said. "In no area has public and private indecision and lack of cooperation between the public and private sectors been more prevalent. The time has come to make the decisions on exchange arrangements and transportation systems that will bring new supplies of Alaska's oil and gas to markets..." Jackson also called for a vigorous exploration program on the North Slope and expansion of the pipeline to its full capacity.

Since most of the opposition is expected to come from House members who voted for the trans-Alaska oil pipeline after being assured the oil would be used solely in this country, Representative Don Young's recent endorsement of the swap, although reluctant, may help overcome some opposition in the House. Although he is still "morally and philosophy-wise opposed" to exporting Alaska oil, Young said he would support a swap if the increased revenue to the state goes to the permanent fund. Young had previously opposed any swap arrangement. Hammond praised Young's "statesmanlike decision which will have an important influence in Congress."

LeResche said it now appears the Carter administration will wait until June, when the Export Administration Act amendments expire, before sending the proposal to Congress. "They prefer not to raise it when a one-house veto is possible," LeResche said. "The President will be the one to win or lose in Congress, so it's their strategy, not ours."

The New York Times, citing the need to encourage domestic production on the North Slope, endorsed the royalty oil swap with Mexico and Japan in a January 21 editorial.

Officials of the American embassy in Japan conveyed their tentative approval of the idea to Lt. Governor Terry Miller when he visited Tokyo in December.

At a December 14 meeting, the Western Interstate Energy Board approved a resolution offered by Alaska urging President Carter to approve the royalty oil swap. The resolution also included support for the foreign exchange of California state-owned royalty oil.

MINNESOTA REJECTS NORTHERN TIER PIPELINE

The Minnesota Energy Agency recently denied a certificate of need for the 75-mile Minnesota section of the proposed Northern Tier pipeline, which would carry Alaska and imported oil inland from Port Angeles, Washington.

The agency's director said he denied the certificate based on estimates that Northern Tier would not have a big enough crude oil market to make the project financially feasible. The certificate is required by Minnesota law before major energy facilities can be built.

A spokesman for Northern Tier Pipeline Company called the agency's denial a major setback, but said the company would not abandon the project. The agency's decision can be appealed in state court.

The $1.6 billion, 1,557-mile pipeline had been planned to terminate in Clearbrook, Minnesota.

Agency Director John Millhone said the decision might be reversed if President Carter selects Northern Tier under the new Crude Oil Transportation Systems law, if Northern Tier gets enough commitments from shippers for moving crude through the line, or if another proposed pipeline, the Northern Pipeline, isn't built in Minnesota.

The Northern Pipeline would carry oil from Wood River, Illinois, to the Minneapolis-St. Paul area. Under this proposal, oil from the Gulf Coast, including Alaska oil, would be brought by barge up the Mississippi River to Wood River.

Millhone said Northern Tier needs to ship 540,000 to 600,000 barrels a day to make its proposal economic. However, he said, current estimates suggest a shortage of only 68,000 to 100,000 barrels a day in northern tier states by 1980, rising to 485,000 barrels a day by the year 2000 as Canadian supplies are cut back.

A recent study for the Northern Tier Pipeline Company suggested that only 140,000 barrels a day of North Slope crude can be accommodated in northern tier state refineries.

Despite its problems with the eastern end of the line, Northern Tier may have come up with a way to head off environmental opposition at the western end. The company is considering a routing change that would eliminate tanker traffic in Washington State's Puget Sound, The Oil and Gas Journal reported January 15. The new proposed route, partially on land and partially under water, also would allow the line to serve four refineries on northern Puget Sound.

Most Alaska officials familiar with the surplus issue favor as solutions foreign exchanges of Alaska oil and conversion of West Coast refineries over any of the proposed pipelines.

A study recently conducted by Battelle Northwest gave the following estimated wellhead prices based on current prices and assuming a 62¢ per barrel field cost and a TAPS tariff of $6.16 per barrel:

West Coast via Tanker	Houston via Panama Canal	Houston via PACTEX	Chicago via Northern Tier	Chicago via Foothills
$5.17/B	$3.11/B	$4.96/B	$4.84/B	$4.10/B

STATE ANALYSIS CRITICIZES FOOTHILLS PROPOSAL

The proposal to construct a major oil port at Skagway and oil pipeline into Canada appears to have major environmental drawbacks and little economic advantage for Alaska, a preliminary state study concludes.

The 500,000 barrel per day pipeline was proposed by Foothills Oil Pipe Line Ltd. of Canada and Northwest Energy Company of Salt Lake City as a way to move surplus Prudhoe Bay oil inland to the midwest. The companies in December filed formal application with the Interior Department under Title V of the Public Utility Regulatory Policies Act of 1978, which establishes an expedited federal process for selecting one or more pipelines to alleviate the West Coast oil surplus and an oil shortage in northern tier states.

"From the standpoint of revenue, there seems to be a consensus that none of the pipeline alternatives are particularly attractive if the West Coast oil surplus is alleviated either through changes in refinery capacity or exports of ANS crude oil. The cost figures supplied by Foothills are viewed with skepticism, and if any revision occurs, it will likely increase the transportation costs of the Foothills proposal. There will be a corresponding decrease in wellhead value and revenue to the state," said the preliminary report, which was written by the governor's Division of Policy Development and Planning based on analysis by eight state departments.

"The environmental risks of large tanker traffic in Chatham Strait, Lynn Canal and Taiya Inlet would be considerable. Many resources of great value (commercial salmon catches alone are worth more than $13 million annually) to Southeast Alaskans would be exposed to the threat of major oil spills," the report said.

"Given the uncertainties, there doesn't appear to be any persuasive argument at this time for the State of Alaska to favor construction of a crude oil pipeline from Skagway into Canada. In a way, Alaska's perspective is similar to that of Canada's in weighing the Kitimat pipeline proposal -- we Alaskans are being asked to bear most of the environmental risks while most of the benefits accrue elsewhere," the report concluded.

The cost of moving oil through the Foothills line would be about 4.6¢ per barrel per 100 miles, based on construction costs estimated by Foothills. The state report, noting that the Trans-Alaska Pipeline moves oil at about 77¢ per barrel per hundred miles, said the Foothills construction cost estimates appear unrealistically low.

Skagway, the Southeast Alaska community where most of the construction activity would occur, probably would be polarized by the pipeline, the report said. About 800 to 900 people would be employed in Skagway during construction of the oil port and pipeline and about 300 to 500 after construction, the report estimated. Skagway's general population would increase between 1,100 to 1,300 during construction and between 400 and 700 afterward.

Foothills spokesman Ron Rutherford said he was "surprised and disappointed at their conclusion that our project doesn't do much for the state...I realize there are environmental objections, but any port anywhere on the West Coast will have environmental disadvantages."

Rutherford said the Foothills project does improve wellhead values and state revenues when compared with the current arrangement of shipping Alaska oil through the Panama Canal to the U.S. Gulf. "I understand that exports are better from the state's perspective, that we're secondary to exports," he said.

An analysis by Battelle Northwest indicates that Alaska oil delivered to Chicago via the Foothills pipeline would have a wellhead value of $4.10 a barrel, compared to a wellhead of $3.10 a barrel for oil delivered to Houston through the Panama Canal.

Rutherford said the Foothills proposal should not be compared with the Alyeska experience, since much of the TAPS line had to be built above-ground due to permafrost while the Foothills line would be buried and conventionally constructed.

Leasing

ADMINISTRATION INTENDS TO HOLD LEASE SALES

The Hammond administration says it fully intends to hold every one of the 15 oil and gas lease sales on its new five-year schedule, including the Beaufort Sea sale set for December, if the federal government approves exports of Alaska oil.

Natural Resources Commissioner Robert LeResche told a joint meeting of the House and Senate Resources Committees January 31 that the state's commitment to hold the Beaufort Sea lease sale on schedule will be reconsidered "sometime this summer on the basis of whether they allow exports or not."

If the state receives permission to export or exchange Alaska oil, "we will hold (the sale) in December of '79," LeResche said. But if it's unclear whether export permission will be granted, "we could well delay or cancel it for that reason." He said the state would be "crazy" to hold the sale if export permission is denied, and pointed out that this stance "is causing some consternation in Washington."

When pressed on whether the administration actually would cancel the sale if the situation is not resolved by summer, LeResche said it would be a "difficult judgment call" and not an "easy yes or no."

LeResche also said "unforeseen legal and environmental problems or local objections" might alter the schedule.

In submitting the five-year leasing program as required by the new leasing law (HB 854) passed last session, LeResche said the future rate of leasing will be predictable, constant and moderate. The administration wants to promote orderly development, minimize environmental and social impacts, maximize revenues and establish incentives for the oil industry to remain healthy and stable in Alaska, he said.

Industry reaction to the leasing plan was generally favorable. "I think it's upbeat," one oil lobbyist said. "They're expressing an optimistic tone to which we're unaccustomed."

The statute does not require any legislative action on the five-year program, but LeResche suggested that "the legislature is clearly the perfect vehicle" for public comment on it.

The plan put forth by the administration listed the following areas and dates for sales:

1979 - July	Copper River Basin (exempt acreage sale) 1/
- December	Beaufort Sea (state-federal sale)
1980 - Early	Relinquished tracts on Arctic Slope (exempt acreage sale)
- Mid	Cook Inlet south of Kenai River (exempt acreage sale)
- Late	Upper Cook Inlet onshore and offshore including the Susitna Valley
1981 - Early	Lower Cook Inlet offshore and onshore (coordinated with planned federal sale)
- Mid	Prudhoe Bay uplands
- Late	Norton Basin offshore and onshore (coordinated with planned federal sale)
1982 - Early	Second Beaufort Sea sale (submerged lands)
- Mid	Middle Tanana Basin and Copper River Basin
- Late	Southwest Bristol Bay uplands

1/ Exempt acreage is acreage that can be leased by the commissioner under certain conditions, even though it did not appear on the five-year schedule.

1983 - Early	Upper Cook Inlet onshore and offshore including Susitna Valley (possible drainage sales)
- Mid	Chukchi Sea onshore and offshore (coordinated with planned federal sale)
- Mid	Norton Basin
- Late	Minchumina Basin

LeResche described the governor's new Agency Advisory Committee on Leasing (AACL), which will advise him on the economic, social and environmental impacts of specific proposed lease sales. The committee, to be chaired jointly by the Commissioner of Natural Resources and the Director of Policy Development and Planning, also will include the commissioners of Revenue, Fish and Game, Community and Regional Affairs, Transportation and Public Facilities, Environmental Conservation, Labor, the Attorney General, and an ex officio member from the community or borough where the lease sale is planned.

The committee is to submit a report to the governor at least three months before each major lease sale, Hammond said in a January 5 administrative order creating the committee.

Regulations implementing the new leasing law have been developed by the Department of Natural Resources and will soon be reviewed by other state agencies. The regulations are expected to go to public hearings by late March or early April, and the department hopes to adopt final regulations by mid-May.

Provisions of the New Leasing Law

The most major change in the new law was to expand the commissioner's choice of bidding methods. Formerly the law allowed only one system for leasing state petroleum resources (cash bonus/fixed royalty), but under the new law the commissioner has the following options:

-- A cash bonus bid with a fixed royalty share of not less than 12-1/2 per cent.

-- A cash bonus bid with a fixed royalty share of not less than 12-1/2 per cent and a fixed share of the net profits of not less than 30 per cent.

-- A fixed cash bonus with a share of the net profits as the bid variable.

-- A fixed cash bonus, a fixed royalty share of not less than 12-1/2 per cent and a share of the net profits as the bid variable.

-- A fixed cash bonus with the bid variable a royalty share of not less than 12-1/2 per cent. This method can be used only when the commissioner determines there is evidence that the unleased acreage is subject to drainage by offsetting wells.

Another change in the new law includes a provision requiring companies to give the commissioner "access to all noninterpretive data" obtained from state leases, although the information must be held perpetually confidential at the request of the companies. Previously, companies only had to provide technical information obtained from wells, which was held confidential for two years; the new law does not affect this requirement.

The new law allows, but does not require, the commissioner to establish an "exploration incentive credit" system that would allow companies to earn "credits" for drilling exploratory wells. The credits could be applied against royalties, rental payments and severance taxes. The credit system, modeled on a similar program in Alberta, "has proven to be successful as a way of encouraging high levels of exploratory activity, and in Alberta has been largely responsible for the record-breaking levels of drilling activity in recent years, and subsequent high rates of discoveries since it was introduced in 1974," a Sohio spokesman said in testimony last spring.

The commissioner's authority to reduce royalty payments when a field begins later stages of production decline was restrained by the new law with the adoption of stricter criteria.

The maximum size of any one lease was increased from four square miles to nine square miles in the new law, and the rental rate on state oil and gas leases also was increased.

Philosophical Questions Remain

While the new law outlines goals for the state's leasing policy, it does not resolve several major philosophical questions, including:

-- Should the state share with the oil companies the multi-million dollar risk of oil exploration, as it would do if it deferred a large upfront cash bonus and opted instead for a share of the "net profits" after oil is found and production begins? In what situations might this approach be to the long-run, economic benefit of the state? In what situations might it stimulate industry activity?

-- How quickly does the state need or desire the revenue it will gain from selling its resources? Cash bonus bidding would bring in a large, lump sum payment at the time of sale; net profits bidding would stretch out the payment over a period of years in the future, assuming oil is found and produced.

These questions, as well as technical information on the physical characteristics and resource potential of the area, and analysis of the potential economic payoffs expected, will influence the commissioner's decision on which bidding method to use in any particular sale.

Beaufort Bids Considered

Because the Beaufort Sea is considered a "highly prospective" area, and may be the state's best hope for finding large accumulations of oil and gas, the choice of a bidding method could have long-term economic implications.

Some people believe that a risk-sharing bid, like net profits, should only be used in a low-risk area where resources are proven or expected to exist. Others say a net profits bid should be used to encourage industry exploration in high-risk areas where the resource potential is more speculative.

Tom Cook, director of the Division of Minerals and Energy Management, said he leans toward use of cash bonus bidding for the Beaufort Sea sale. The net profits method "will be a nightmare" and will require a staff of 15 to 20 economists to administer it, Cook told a group of legislators, consultants and staff in Juneau recently.

"My personal preference is that I lean toward something doable, something we can administer and manage," Cook said. "I have a prejudice to simple approaches, but I'm trying to be open minded." Cook also opposes the concept of state risk-sharing on philosophical grounds.

If the state does use cash bonus bidding, Cook said he would suggest that the fixed royalty share be increased from one-eighth to one-sixth or possibly one-fifth. "This is the only state in the union that's still leasing one-eighth (fixed royalty). Most other states and the federal government have gone to a higher fixed royalty," he said.

Ed Phillips, a petroleum economist with the division who has been analyzing the various bidding alternatives, said it is his personal opinion that "there are many areas in the Beaufort Sea where net profits bidding would be good."

"This is a complex problem, and there are three big uncertainties," Phillips said. "You don't know if there's oil there; you don't know the cost of getting it out; and you don't know what price you'll get for it if you do get it out. Different bidding systems will yield different amounts of income to the state." Phillips said he is setting up a computer model that compares the expected income to the state under different bidding methods and under different assumptions about oil potential, costs and prices. The division is cooperating with the federal Bureau of Land Management in making the same analysis on a tract-by-tract basis.

The oil companies are generally negative about the state assuming a portion of the exploration risk and prefer the traditional cash bonus bid. As Exxon stated in testimony to the House Resources Committee last March, "Sharing in net profits would signal the state's entry into the production phase of the oil business. It might be politically and economically difficult for the state not to be deeply involved in decisions about day-to-day operations and thereby become an operating partner."

Others, however, argue that a greater assumption of risk by the state would maximize state revenues, reduce the adversarial nature of the state-industry relationship, give the state greater control in the pace of development, and lessen the need for continual tax increases.

A study currently being conducted by White Weld/Merrill Lynch for the Joint Committee on Gas Pipeline Financing will address the benefits and drawbacks of "alternative institutional frameworks under which oil and gas resource development could take place in Alaska."

A bidding method for leasing the state's offshore Beaufort Sea lands has not yet been determined and probably won't be until late spring or early summer. Cook will make a recommendation to Commissioner LeResche, who will make the final decision on bidding terms for the sale. Cook said that although the law does not require it, there will be an opportunity for public comment before proposed bidding terms are finally adopted.

The Federal Perspective

Although the "Memorandum of Understanding" (MOU) signed last spring by Governor Hammond and Interior Secretary Andrus anticipated that joint terms, conditions and procedures would be applied to all Beaufort Sea lands in the sale area, whether they are state, federal or disputed, it has been difficult for the state and federal agencies to agree on a number of points.

Cook said that state and federal managers have now reached "general agreement" on a management structure and on a number of areas where joint regulations and procedures are feasible, including how disputed lands (where both the state and federal government claim title) will be managed while ownership is settled, the basis for unitization (can units include both state and federal tracts?), and mitigating measures to protect the environment. The state and federal government also have agreed to conduct a joint Environmental Impact Statement.

On other points, however, it now appears the state and federal government will proceed in separate directions. Major areas where joint procedures apparently are not feasible, Cook said, include bidding methods and the imposition of restrictions on joint bidding by the oil companies.

The federal government is leaning toward use of sliding scale royalty (not an option under state law) and net profits as bidding methods, Cook said. Even if the state and federal government were both to select the net profits method, Cook said, he would not agree to use the "convoluted" federal definition of net profits.

With respect to joint bidding by major oil companies, state law allows it and federal law does not, although the Interior Secretary can waive the joint bidding ban if he determines that exploration and development will have an extremely high cost and will not occur unless an exemption is granted. Both the Antitrust Division of the Justice Department and the Federal Trade Commission have urged Interior not to grant Chevron's request to lift the restriction for the Beaufort sale. Cook said that although he does not yet have a formal legal opinion, "it may be that the state doesn't have the power to restrict joint bidding," since a provision giving the commissioner authority to do so was dropped from early versions of the leasing bill and was not included in the version that finally became law.

Some believe it will be difficult for the state and federal government to pull off the sale on schedule this December, considering the administrative problems, legal challenges and general opposition from Natives who live near the proposed sale area, and uncertainty about environmental effects, particularly on the bowhead whale.

Exxon executive Monte Taylor recently visited Juneau to "impress on the governor the importance of keeping it on schedule," or at least letting industry know as soon as possible if it will be delayed.

"We've got 15 to 20 people working on the Beaufort Sea...we're spending a lot of money getting ready," Taylor said in an interview with the public television show, Capital 79.

Although the villages of Nuiqsut, Kaktovik and Barrow have been denied injunctions attempting to halt preparatory drilling near the sale area in both federal and state courts, their cases against the state, the U.S. Army Corps of Engineers and Exxon are still pending. Cook said he thinks it is "very likely" that Exxon will have completed its drilling from a man-made gravel island in the mouth of the Sagavanirktok River before the case comes to trial.

Sohio recently got permits from the state and federal governments to construct a similar gravel island in shallow water on the northern edge of Prudhoe Bay. Alaska Legal Services, which is representing the Natives in the suits against Exxon and the governments, has threatened to challenge Sohio's drilling in court as well.

INTERIOR ISSUES DECISION ON PLO 82

The Department of Interior has issued a legal opinion that affirms the state's ownership of Prudhoe Bay but claims federal ownership of other large sections of offshore Arctic Alaska.

The December 12 opinion by Interior Solicitor Leo Krulitz, which has been approved by Secretary Cecil Andrus, claims federal ownership of offshore lands bordering on the Arctic National Wildlife Range and the National Petroleum Reserve in Alaska (NPRA). This means, in effect, that the state would own only the narrow, three-mile strip of offshore Beaufort Sea lands between the two federal withdrawals.

In addition, the Interior opinion claims federal ownership of inland submerged lands (navigable lakes and rivers) within the large land area withdrawn by the federal government in Public Land Order (PLO) 82.

Both the offshore lands and the inland submerged lands now being claimed by Interior as federal property formerly were thought to have passed into state ownership at statehood.

Assistant Attorney General Tom Koester said the opinion is "unacceptable to the state with respect to ownership of the inland water bodies and ownership of the offshore submerged lands not expressly included in the withdrawals for NPRA and the wildlife range." Koester said the state is now evaluating its legal options for seeking a reversal in those two areas. However, he said, "we are pleased that the solicitor has confirmed the state's ownership of the lands under Prudhoe Bay."

PLO 82 withdrew more than 48 million acres of Alaska lands north of the Brooks Range crest for military purposes in 1943, but the order was revoked in 1960.

"The issue involving coastal submerged lands has been raised in connection with a proposed sale of oil and gas resources in submerged lands in the Beaufort Sea off northern Alaska, which would be a joint sale conducted by the (Interior) Department and the State. The need to clarify the status of ownership in connection with this proposed joint sale has been the catalyst which has prompted this opinion," the solicitor's opinion said.

Current ownership of the lands, Krulitz said, is based on: (1) whether PLO 82 withdrew either offshore submerged lands or inland submerged lands in northern Alaska; (2) if so, whether this withdrawal effectively prevented transfer of federal ownership to the State of Alaska upon statehood; and (3) if so, whether revocation of PLO 82 in 1960 vested ownership of lands in the State.

Krulitz concluded that the coastal submerged lands were not withdrawn by PLO 82 and consequently passed to the state at statehood. However, he said, the offshore lands abutting NPRA were reserved by the federal government in Executive Order 3797-A of February 23, 1923, and did not pass to the state at statehood. The offshore lands abutting the Arctic National Wildlife Range were reserved to the federal government by the Bureau of Sport Fisheries and Wildlife application for a withdrawal dated January 14, 1958, and do not belong to the state, he said.

"I have also determined that, in contrast to the coastal submerged lands, the inland submerged lands were withdrawn by PLO 82, did not pass to the State of Alaska at statehood, and remain in federal ownership despite the revocation of PLO 82 in 1960, except where the State of Alaska has selected the submerged lands in question and the Federal Government has approved these selections," Krulitz said.

Koester said it is impossible to determine how much acreage is affected by Interior's opinion on the lakes and rivers since there is some dispute about how navigability is defined. The state favors the view "that if you can land a float plane on it, it's navigable," Koester said. However, the federal government, which has clear title to the non-navigable water bodies, wants navigability based on proof of historical use in trade and commerce.

ALASKA URGES INTERIOR TO POSTPONE PROPOSED OCS SALES

About a third of 11 federal offshore lease sales proposed in Alaska for 1980-85 should be postponed indefinitely, Governor Jay Hammond recommended recently to Interior Secretary Cecil Andrus.

Interior is in the process of drawing up a new five-year leasing schedule for all Outer Continental Shelf (OCS) areas in the United States. Of 22 areas proposed for sale in the next five years, half are in Alaska. Interior's "draft proposed program," which will name specific dates and areas for leasing, will be submitted to Hammond and other governors by March 2.

Under 1978 amendments to the federal OCS Lands Act, Interior is required to solicit comments on the proposed five-year plan from states, local governments and interested members of the public.

In a December 12 letter to Andrus, Hammond said proven technology for development in the 1980-85 period currently exists in only three of the 11 proposed sale areas -- the nearshore Beaufort Sea, the Gulf of Alaska (Yakutat tracts) and the Lower Cook Inlet/Shelikof Strait.

Proposed sales in four other areas -- Navarin Basin, Norton Basin, Hope Basin and the Kodiak Shelf -- "need to be delayed until proven, safe technology is developed through experience gained in the nearshore Beaufort Sea," Hammond said. The governor recommended "sequential nearshore to offshore progression of development" for these areas. "The nearshore areas of Norton and Navarin Basins may be appropriate areas for leasing by 1983-85, assuming advanced exploratory and development drilling techniques and mitigating measures are developed in the nearshore Beaufort Sea by the early 1980s, and if district coastal management plans are satisfactorily completed," he said.

Sales in five other areas -- Chukchi Sea, Southern Aleutian Shelf, St. George Basin, Bristol Basin and the Beaufort Sea ice shear and offshore pack ice zones -- "need to be postponed indefinitely pending resolution of major renewable resource conflicts, availability of a comprehensive coastal environmental data base for development of strengthened regulatory mechanisms, decisions on marine sanctuary designation or other protective classification, evolution of Arctic technological capability and completion of coastal management plans," the governor said.

Interior's current proposal would mean about two federal OCS lease sales a year for the next five years, Hammond said, and the economic and environmental effects of the separate sales will interact.

"The total impacts associated with these separate activities would likely be cumulative and the total impacts would differ significantly from what one would expect from 11 separate sales," he said. The governor questioned whether the current Environmental Impact Statement process, which will examine each sale separately, would be adequate to assess the cumulative effect of 11 sales in five years.

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Hammond reiterated the state's "grave concern" that environmental assessment research programs be adequately funded, and urged Interior to seek a supplemental appropriation from Congress for the current fiscal year.

Hammond also said he considers resolution of the West Coast surplus "inseparable from federal planning for major oil and gas leasing on Alaska's OCS...

"Clearly the United States government must mesh its accelerated leasing plans with the realities of existing refinery capacity, the existing transportation systems, and the institutional mechanisms which affect the incentives for industry to adjust these facilities and systems," he said.

Until some solution is implemented to alleviate the surplus -- such as retrofitting existing West Coast refineries, constructing one or more of the west-to-east crude oil pipelines, or exporting North Slope oil to Japan in return for other foreign oil delivered to the U.S. Gulf and East Coasts -- "anything that increases the crude oil supply on the West Coast can only serve to exacerbate this problem," the governor said.

INTERIOR CALLS FOR NOMINATIONS IN LOWER COOK INLET

Interior's Bureau of Land Management has invited the oil industry to nominate tracts for possible inclusion in the planned OCS sale in Lower Cook Inlet, now tentatively scheduled for March, 1981.

BLM also asked for comments on geological, environmental, biological, archaeological and socio-economic problems that might affect leasing and development of specific blocks. The call for nominations and comments, due by February 28, is a preliminary step to selection of tracts for further environmental analysis and study.

The area covered in the present call for nominations includes all of Lower Cook Inlet south of Kalgin Island (except tracts leased in the October, 1977, sale), and the Shelikof Strait as far south as Cape Ikolik on Kodiak Island.

Gas Pipeline

SCHLESINGER SUGGESTS FEDERAL LOAN GUARANTEE FOR ALASKA HIGHWAY PIPELINE

Energy Secretary James Schlesinger says a $2 billion to $3 billion federal loan guarantee may be needed to build the Alaska Highway gas pipeline if private financing can't be arranged.

Schlesinger made the remark in testimony before the Joint Economic Committee of Congress in response to questioning by Senator William Proxmire of Wisconsin, the Wall Street Journal reported January 24.

Previously, the administration had maintained that the Alaska pipeline could be privately financed, as required by federal law.

In a mid-January address in New York, Schlesinger labeled the project a "high priority" of the administration and urged the financial community to remain sympathetic until regulatory decisions are resolved. Even in the unlikely event of a 90 per cent cost overrun, Schlesinger said, the Alaska project will be more beneficial to the nation in the long run than other alternative gas supplies whose prices are tied to the world price of oil.

Schlesinger told the Senate Energy Committee that although the long delay over the natural gas pricing bill had caused the Alaska project to lose momentum, the Federal Energy Regulatory Commission (FERC) should have "pulled the regulations in place" within the next 60 days.

Schlesinger's prediction of quick FERC action is considered unreasonably optimistic by most observers. FERC's latest order on one aspect of the Incentive Rate of Return (IROR) outlined a procedure for resolving more than a dozen complex matters, several of which will require separate rulemaking procedures. Considering the length of time it has taken FERC to establish even the basic structure of the IROR (the first notice of rulemaking was issued last May), it is almost certain that regulatory deliberations will drag on for many, many months, or perhaps a year.

Despite Schlesinger's renewed assurances of support, the Alaska Highway gas pipeline project continues to face enormous obstacles and problems.

President Carter still has failed to nominate a Federal Inspector and submit his proposal for reorganizing the federal bureaucracy, long-delayed actions that had been expected by the time Congress convened January 15. The reorganization will affect the departments of Agriculture, Energy, Interior, Labor, Transportation, Treasury, the Environmental Protection Agency, the Army Corps of Engineers and the Federal Communications Commission, and will transfer their enforcement authorities over construction of the Alaska pipeline to the Office of the Federal Inspector.

Alaskan Northwest, sponsor of the Alaska segment of the pipeline, recently told federal officials in Washington it now expects to complete the project in the "winter season" of 1984-85, a year later than the previous estimate.

Although Northwest's ability to secure private financing for the project remains in doubt, the project sponsors appear to have momentum in their favor on the critical issue of who should build and pay for the North Slope conditioning facilities, estimated to cost about $2 billion. FERC has under consideration a proposed rulemaking that would place responsibility for these facilities on the producers, but it has not been formally adopted. If this view ultimately prevails, Northwest will be relieved of one major task. The producers do not like this proposal, however, and it could weaken their interest in producing and selling the gas.

Congress is expected to begin reexamining the necessity for an Alaska gas pipeline in the context of hearings this spring on the overall gas supply situation, with particular attention to Canada and Mexico. While some members of Congress still strongly support the Alaska gas line for national security reasons, some other pro-consumer congressmen, like Senator Edward Kennedy, are questioning why consumers should pay for expensive Arctic gas when cheaper, closer supplies are, or may be, available. At Schlesinger's appearance before the Joint Economic Committee of Congress, Senator Kennedy accused the Energy Secretary of spurning Mexican gas and of tailoring federal policies to raise domestic gas prices enough to justify construction of the Alaska gas line, the Wall Street Journal reported.

Given all the uncertainties and lack of progress at the federal level, it appears increasingly unlikely that either the state administration or the legislature's Joint Gas Pipeline Financing Committee will recommend that state funds be committed to the project during the current legislative session. Governor Hammond, in his State of the State address, said, "It is totally premature for the state to make final decisions regarding what, if any, financial investment we may wish to make."

Northwest, however, reportedly intends to make a strong push for an early state commitment of $500 million in equity, as well as an attempt to convince the state to sell its royalty gas for export through the pipeline.

Some of the issues affecting progress on the project are discussed in more detail below.

Conditioning Costs

A proposal that would require gas producers to pay for the costs of gas conditioning out of the $1.63 per million Btu maximum wellhead ceiling price has been on FERC's agenda since early December, but has not yet been adopted as a formal "proposed rulemaking." If the proposal is adopted, there likely will be an extended period for comment by the various parties before the matter is finally settled by FERC. FERC's decision could be appealed to the courts.

If the conditioning costs are included within the ceiling price, the value of the gas to the producers probably would drop below $1. The producers also object to this proposal because it would require that they, rather than the pipeline sponsors, bear the front-end financial burden of raising about $2 billion to build the facilities.

The proposal under consideration by FERC says this arrangement is "necessary to insure the marketability of the gas."

It is presently unclear what effect this proposal, if adopted, would have on state royalty gas, whether the wellhead value used to calculate royalty and severance tax payments would be the ceiling price, or the ceiling price minus the estimated 75¢ conditioning cost. Natural Resources Deputy Commissioner Fred Boness said the matter might have to be settled in court.

Field Economics

In order for the pipeline to go forward, gas sales contracts will have to be negotiated between the North Slope producers and the pipeline companies. There must be buyers and sellers who agree on an acceptable price for the gas.

It is not known, except perhaps by the producers themselves, at what price it will be economical to produce and sell the gas, considering the amount of investment required for conditioning facilities, pressure maintenance, and the cost of reinjecting the gas if it is not produced.

The Department of Natural Resources and the Legislative Affairs Agency's Research Division are now reviewing proposals for an analysis on the economics of producing gas from the Prudhoe Bay field. This economic analysis will "model" the costs of producing and not producing the gas, as well as predict returns expected under a range of conditions, based on engineering profiles of the reservoir.

Pipeline Pressure

Northwest wants to build a 48-inch diameter pipeline with an operating pressure of 1,260 psi (pounds per square inch), while Atlantic Richfield and the state favor a higher pressure, 1,440 psi system.

Northwest currently is preparing a report on the issue for presentation to FERC, which will make the final decision. Members of the pipeline consortium met with state officials in Juneau recently in an attempt to get the state to change its position.

The higher pressure, 1,440 system would be able to move gas more cheaply at throughput levels above 3.4 billion cubic feet (bcf) a day. Below that throughput level, the 1,260 system can move gas more cheaply per unit, according to figures supplied by Northwest.

Since gas production almost certainly will be limited by reservoir management considerations, throughput from the Prudhoe Bay field probably will not exceed 2 bcf a day.

Therefore, Northwest reasons, the lower pressure system will be more efficient at the throughput level expected. Northwest says the 1,260 system could be expanded to accommodate a throughput of 3.2 bcf a day with additional compressors, and it maintains that this is adequate extra capacity.

The state and others argue, however, that future discoveries likely will increase the amount of gas available for production, and that it would be much cheaper to put in extra capacity during initial construction rather than adding it later. (For a more full explanation of the state's position, see "Energy Background Report #3," December 8, 1978, Page 6.)

In addition to the advantage of improved efficiency at the lower throughput level, Northwest Vice President Darrell MacKay gave a number of other reasons for selecting the 1,260 system.

Northwest maintained that any change in its plans to build the lower pressure system will delay completion of the project at least a year, jeopardize the project's economic viability, frighten off prospective financiers, and render useless many months of predesign and engineering work.

Lenders are not willing to take the technological risks associated with the higher pressure system, MacKay said, noting that no large-diameter gas transmission pipeline has ever been built with a design pressure greater than 1,100 psi.

With respect to the amount of liquids that can be carried at the different pressures, Northwest presented figures showing that the higher pressure, 1,440 system can carry a slightly greater (8,000 barrels a day) amount of butane and heavier liquids. Northwest emphasized, however, that both systems could carry the same amount of ethane and propane.

"We believe and agree with Bonner and Moore that ethane is the best material for petrochemical feedstock," MacKay said. Since the 1,260 line could carry almost double the maximum amount of ethane needed for a world-scale petrochemical plant, MacKay said, "we don't think we've inhibited your flexibility" in developing a petrochemical industry.

The figures presented by Northwest are shown below, and they reflect the amount of liquids that could be carried in the gas stream at the 1,260 and 1,440 pressures.

PRUDHOE BAY FIELD
NATURAL GAS LIQUIDS
GAS PRODUCTION RATE OF 2 BILLION CUBIC FEET
PER DAY

	Natural Gas Liquids (thousand barrels/day) Design Pressure (psig)		
	1260	1440	Increase
Liquids Acceptable in Gas Stream			
Ethane	98	98	-
Propane	53	53	-
Butane	9	15	6
Pentanes and heavier	2	4	2
	162	170	8
Liquids Not Transportable in Gas Stream			
Ethane	0	0	-
Propane	0	0	-
Butane	22	16	(6)
Pentanes and heavier	22	20	(2)
	44	36	(8)

These figures, however, do not represent the actual amount of liquids that will be carried if the producers implement their current plans as set out in the conditioning plant study by the Ralph M. Parsons Co. The producers, at this time, plan to burn a large portion of the liquids as fuel on the North Slope.

Figures developed by Earth Resources Company of Alaska (ERCA) and Northwest forecasting the amount of liquids that actually will be carried at the 1,260 pressure are shown below.

NATURAL GAS LIQUIDS
(Barrels per day)

	ERCA	Northwest
Total Liquids Produced	182,599	226,000
Liquids to be carried in pipeline	75,470	105,000
Ethane	46,500	56,000
Propane	17,970	22,000
Butane	9,000	26,000
Pentanes and heavier	2,000	1,000

Earth Resources of Alaska, which is the parent company of North Pole Refining in Fairbanks, made a presentation at a recent royalty board meeting urging the state to reject the lower pressure, 1,260 system and the current plan to build the conditioning facilities on the North Slope.

ERCA suggested that a high-pressure 1,680 system be constructed from the North Slope to Fairbanks to deliver the entire, unconditioned gas stream, including almost all the liquids. A gas conditioning and separation facility to remove the liquids should be built at Fairbanks, ERCA said. The treatment and separation facility should be financed and operated by the state under an AGSOC concept backed by the permanent fund, they suggested, and the portion of the natural gas pipeline between Prudhoe and Fairbanks also could be partially financed through the AGSOC.

"The proposal submitted by the Ralph M. Parsons Company, and being considered by FERC, considers the burning of a good portion of the gas liquids as fuel at Prudhoe Bay," ERCA said in a "white paper" presented to the royalty board. "Permitting such burning of gas liquids minimizes any opportunity to develop a viable gas liquids separation plant in the Interior and detracts from the viability of developing a petrochemical plant in Alaska."

Incentive Rate of Return

FERC's latest order (No. 17-A of 1/17/79) settled the issue of whether an Allowance for Funds Used During Construction (AFUDC) will be included in the Cost Performance Ratio of the IROR mechanism. AFUDC will be included, despite assertions by Northwest that the arrangement will hinder attempts to arrange private financing.

FERC made some adjustments in its earlier order (No. 17 of 12/1/78) and agreed with Northwest that the pipeline sponsors should not be penalized for delays beyond their control. However, FERC kept the basic structure of its December order intact.

The Incentive Rate of Return mechanism, mandated in the President's Decision selecting the Alaska Highway pipeline route, is supposed to prevent large cost overruns like those experienced during construction of the Trans-Alaska oil pipeline. The IROR will allow the pipeline companies and other equity investors to earn a high rate of return if the project is constructed within or under budget, but it will reduce earnings if the project ultimately costs more than projections.

Despite Order 17-A, many issues with respect to implementing the IROR remain unresolved.

Marketability

Whether Lower 48 consumers will be willing to buy high-cost Alaska gas continues to be an issue of speculation, in spite of the "rolled-in" pricing provisions in the new Natural Gas Policy Act.

Secretary Schlesinger recently told the Senate Energy Committee that the present combined wellhead and delivery price for Alaska gas is about $4.85 per million Btu's (Foster Report of 1/18/79). Schlesinger estimated that this would decrease during the life of the pipeline to $3.50 by 1995 and $3.12 by the year 2000. He said he would oppose any attempt to equalize the cost of pipeline transportation over the life of the line. While this would reduce the burden on today's consumers, it would increase risks and result in higher capital costs, he said.

A recent report by the Congressional Research Service, however, indicated that delivered Alaska gas is likely to cost $5.58 to $6.30 per million Btus in 1985. 1/

Consultants Arlon Tussing and Connie Barlow said in a January report to the legislature: "Gas delivered through the Alaska Highway system would cost Lower 48 consumers more than twice today's prices for fuel oil, and although oil prices are almost certain to keep rising, there is no assurance that Alaska natural gas will be saleable in competition with other fuels over the project's entire economic life." (See next item.)

Actions of Northwest's Corporate Rivals

Midwestern Gas Transmission Co., one of the parties that recently lost the first round of a lawsuit seeking to prevent Northwest from importing

1/ Caution must be exercised in comparing projected costs unless the reference year and other assumptions are specified. The Foster Report quoting Schlesinger's remarks did not name the reference year.

Canadian gas through the pipeline's pre-built Eastern Leg, has now challenged applications of the companies building the pipeline's Western Leg.

Midwestern and others recently asked FERC to hold formal evidentiary hearings on the Western Leg applications, which were filed in November by Northwest Alaskan Pipeline Co., Northwest Pipeline Corp., El Paso Natural Gas Co., Pacific Interstate and Pacific Gas Transmission Co.

Midwestern's arguments center around the legal problems posed by a change in routing for the Western Leg from that accepted in the President's Decision.

This question may prove to be an important test of how closely the applicants will be held to routing and other conditions set forth in the President's Decision approving the Alaska Highway route and its southern sections.

FEDERAL LEADERSHIP NEEDED TO BREAK GAS PIPELINE IMPASSE

The Alaska Highway gas pipeline project will continue to flounder until its sponsors and the federal government face up to the realities that private financing is not possible and an explicit allocation of risks is necessary, legislative consultants say.

Arlon Tussing and Connie Barlow said in a recent report to the legislature that the problems and conflicts now confronting the pipeline project have grown out of three troubling characteristics: (1) its marginal economics, (2) the accompanying uncertainties and risks, and (3) the need for an explicit allocation of those risks.

"What is holding up the project is not the scheduling and resolution of a host of individual events -- incentive rates of return (IROR), conditioning costs, gas sales contracts, etc. -- but a resolution of the basic question of who will bear what risks, and in return for what benefits?"

The risks faced by lenders include the possibilities that the cost of Alaska gas might exceed its market value, that TAPS-like cost overruns might push the project's price tag far above current estimates, that engineering or regulatory problems might prevent completion of the project after actual construction had begun, or that gas production might be interrupted for an extended period.

"Traditionally, large transportation projects have been 'conventionally' financed, that is, in a way that the sponsors are assumed to bear all risks," the report said.

"'Project financing' as proposed for the Alaska gasline, however, is a relatively new technique in which the sponsors risk only their invested equity capital. The sponsors will not be liable for debt service; altogether, their net worth is not large enough to meet this responsibility even if they were willing to do so. Lenders, on the other hand, cannot afford to take any risks when the stakes are so great. They must therefore be assured that some other creditworthy party will assume responsibility for scheduled payments of debt and interest in the event of project non-completion or a shortfall in revenues during some 25 years of operations. The transfer of these risks onto such parties must, therefore, be tight, complete, and explicit," the report said.

"In our view," the authors said, "among all the beneficiaries, only the federal government is large enough, and only the federal government can capture enough of the non-marketable benefits of the project, to be able and motivated to provide the essential financial guarantees."

The report traces some of the history surrounding federal selection and approval of the Alaska Highway project, and points out that the Carter administration and the project's sponsors currently face an almost impossible political dilemma. The Alcan sponsors (now Alaskan Northwest) told Carter the pipeline could be privately financed; the President took those optimistic claims at face value and assured Congress that federal financing assistance would not be necessary.

"Thus the project sponsors and the administration hooked Congress -- and themselves. Their failure to address the financing question openly and realistically from the beginning has sowed seeds of suspicion that could well prove fatal to the project, or at least to its present sponsors, when and if they finally decide to ask for federal help," the report said. "Moreover, the optimism of Northwest and the President that loan guarantees or unconventional tariff designs would not be needed has seemingly been turned into a Congressional dogma that such assistance absolutely shall not be given."

Given these factors, Tussing and Barlow conclude, "on the surface it looks as if the state can avoid for a least another year confronting the difficult policy questions: (1) does the state want to contribute risk capital to assist the project? and (2) what should be done about the royalty gas? After all, until the fundamental risks are explicitly apportioned, it is impossible to make prudent judgments, either on the soundness of financial involvement or on how critical state financing or royalty decisions are to the project's success."

The authors outlined three possible "alternative postures" that the state might take with regard to the project in the coming year:

(1) Defensive -- This approach, which corresponds most closely to the postures taken by both legislative and executive branches in the past year, is grounded on a belief that although it is best for the state to avoid any direct responsibility for progress of the pipeline, it is nonetheless vital for the state to take some action to protect its interests and to stake out bargaining positions. "The driving force to take some action can be either concern that the state might be stuck with the blame of project failure, or recognition of a need to at least keep up with the other parties in asserting its interests and reacting to their proposals."

2. Offensive -- The state could be the first to "lay its cards on the table," hoping that others would then do the same. The state could make a commitment to follow through on a particular action, like equity financing, if certain enumerated conditions were to occur first. While this might be an effective way to jar things off dead center, it might also have a debilitating effect if the state's demands proved to be unrealistic and unachievable.

3. Strategic -- With this posture the state would serve as a behind-the-scenes catalyst in an attempt to get the other parties, particularly the federal government, to turn away from the present adversarial, piecemeal approach. The state would be trying to get each party to understand the financial and political limitations restraining every other party.

John G. McMillian, chairman and chief executive officer of Northwest Alaskan, blasted the Tussing-Barlow report at a recent Fairbanks news conference, according to the All-Alaska Weekly. "We can privately finance this project," he was quoted as saying.

The report, "The Alaska Highway Gas Pipeline: A Look at the Current Impasse," was prepared under a contract between the University of Alaska's Institute of Social and Economic Research and the Legislative Affairs Agency. Copies are available in the agency's Research Division office, or from the Anchorage and Fairbanks public information offices.

Royalty Oil and Gas Development

DEVELOPING AN IN-STATE PETROCHEMICAL INDUSTRY REQUIRES STATE ACTION

Development of an in-state petrochemical industry with Prudhoe Bay gas liquids appears most feasible if the Alaska Highway gas pipeline is scrapped or delayed indefinitely, but the industry is unlikely to develop in any circumstance unless the state exerts stronger leadership, consultants say.

Bonner & Moore Associates, Inc., of Houston, in a January 10 report to the Royalty Oil and Gas Development Advisory Board, recommended the state spend about $300,000 to design and develop a financing plan for a gas liquids pipeline from Prudhoe Bay to tidewater. This pipeline would be "the key...component of a system to use gas liquids in-state," the report said.

The royalty board, meeting in Juneau February 1, voted unanimously to request that the governor seek a supplemental appropriation from the legislature for work on the liquids pipeline as suggested by Bonner & Moore.

The report said the state should consider the possibility of state financing for the project, which could reduce the cost of getting the gas liquids to tidewater by 15 to 20 per cent.

Actively promoting a liquids pipeline "is the only approach we can see that will enable the state to influence events favorably toward petrochemical industry development," the report said.

Consultant Joe Moore said his strategy and recommendations are "predicated on the notion that the gas line is not going to be built, at least not in the near future." If the pipeline is built, it is likely that the value of the gas liquids will be greater if they remain in the gas stream and are exported to the Lower 48.

Private industry is unlikely to pursue development of petrochemical manufacturing in Alaska for several reasons, the report said.

"Regulatory delays, high transportation costs, and a generally negative perception of the business climate in Alaska have resulted in an impasse over the matter of gas production and sale. The prospects of catalyzing industrial leadership in the use of gas liquids in-state are poor for these reasons," the consultants said. "A thoughtful consideration of alternatives has led Bonner & Moore to a reluctant but firm conclusion that only a commitment by the state to lead these activities can significantly enhance the prospects of in-state petrochemical development."

Federal regulations on the pricing of Prudhoe Bay gas will affect the economic viability of the Alaska Highway gas pipeline as well as the feasibility of in-state petrochemical manufacturing. It is uncertain at this time whether the Federal Energy Regulatory Commission ultimately will allow the producers to recover their conditioning costs in addition to the wellhead ceiling price of $1.63 per million Btus, or whether those costs will be included within the price ceiling.

Another big uncertainty is how much Lower 48 gas purchasers are willing to pay for Alaska gas; they may not be willing to pay the ceiling price (plus transportation) regardless of how the conditioning issue is settled.

"At the present time," Bonner & Moore said, "the prospects of selling Prudhoe Bay gas at regulated ceiling prices appear to be dimming. While this is an unwelcome development for Alaska, in that it reduces the royalty value of North Slope gas production, it enhances the prospect that the alternate value of these materials as petrochemical feedstocks will become their most economic disposition and therefore provide the greatest benefit to the state."

Bonner & Moore estimated that the cost of recovering the ethane and heavier liquids at the North Slope and transporting them by pipeline to the Kenai Peninsula would amount to about $1.08 per million Btus. The value of the feedstock to the manufacturer (or the amount he is willing to pay for it), considering petrochemical prices and manufacturing costs, is about $2.10 per million Btus. Therefore, the liquids would have a value of about $1.02 per million Btus at the North Slope. This means a manufacturer may be willing to pay the producers or the state up to $1.02 per million Btus for the liquids at the wellhead. 1/

The consultants outlined three possible outcomes for pricing Prudhoe Bay gas.

Under one scenario, Prudhoe Bay gas is allowed a regulated price of $1.63 per million Btus, plus the cost of gas conditioning, and the gas is sold successfully at that price. In this situation, the prospect for in-state use of the liquids for petrochemicals is zero, the consultants said.

Under the second scenario, Prudhoe Bay gas is allowed a regulated price of $1.63 per million Btus, but no added allowance is made for an estimated 75¢ gas conditioning cost. In this situation, in-state petrochemical manufacturing is "feasible," Bonner & Moore said, since the liquids' "pipeline value" (the amount the producers can get for selling them for export through the pipeline) is about 88¢.

In the third possibility, Prudhoe Bay gas only can be sold at a market clearing price in competition with other gas supplies available to purchasers in the Lower 48. If this were to occur, prospects for petrochemicals are "good," but it is unlikely that the Alaska gas line would be built. Bonner & Moore said that in this situation "the producers could well make a concerted effort to recover and sell gas liquids from Prudhoe Bay, reinjecting only a lean gas stream back into the reservoirs."

"The determination of which scenario will prevail must first await the final regulations on gas pricing to be adopted by FERC. Even these regulations will not completely define the gas pipeline's future because the entire gas project has not met the test of market acceptance. In the view of Bonner & Moore, the gas pipeline project, or at least the Alaskan portion, is not economically sound. Only substantial government subsidization or favorable regulatory bias toward the project will enable its realization."

Moore did not address in the report whether petrochemicals might be feasible if the Alaska Highway gas pipeline ultimately is built and the liquids are transported through it rather than through a separate liquids pipeline.

One problem, however, is that if all the gas liquids are taken out of the gas stream for petrochemical manufacturing and sale as products, the Btu value of the gas stream would be significantly reduced. Although a world-scale petrochemical facility would need no more than 50,000 barrels

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1/ These figures assume that construction costs in Alaska are 40 per cent higher than on the U.S. Gulf Coast. If construction costs were 100 per cent higher, the feedstock value (or the amount the manfacturer can afford to pay) would drop 61 per cent.

a day of liquids out of a total of 150,000 to 180,000 barrels a day of liquids that could be produced, the economies of scale for the extraction plant and products pipeline virtually require extraction of the maximum amount of liquids available. Moore said it might be feasible to remove only 50,000 barrels of liquids a day at Fairbanks, "provided you didn't have to pipeline it somewhere else, if it could be converted into some other product like plastic that could be transported by rail."

Northwest Alaskan Vice President Darrell MacKay told a meeting of state officials in Juneau recently that "if 80 per cent of the ethane and heavier liquids were extracted for petrochemical manufacturing or sale, it would have a very significant effect on our system downstream...Twenty to 25 per cent of the Btu value of the gas stream would be gone. It would affect the economic viability of the whole project."

MacKay said Northwest wants "to help the state accomplish its goal for in-state use of the liquids." However, "we think you'll find that it's more profitable to keep the liquids in the gas stream rather than extract them for export and sale as liquids," he said.

Moore said that if the Northwest pipeline is built, and the liquids are removed for petrochemical manufacturing and sale as products, one solution might be to replace the Btus lost from the Prudhoe Bay stream with Cook Inlet gas transported in a new lateral pipeline.

Royalty Gas Sale Uncertain

It now appears less likely the administration will attempt to conclude a sale of the Prudhoe Bay royalty gas and gas liquids during the current legislative session.

Natural Resources Commissioner Robert LeResche said the administration had been giving serious consideration to selling the royalty gas in a "promotional option" contract "because there's been so much pressure from people, particularly in Fairbanks, who are convinced that the only way to get a petrochemical industry is to give someone a commitment to use the gas."

The Royalty Oil and Gas Advisory Board, which must approve royalty sales proposed by the administration, decided at its last meeting to delay consideration of the sale until mid-March. The board asked LeResche to continue talks with prospective purchasers and to continue work on the draft contract.

The royalty board was divided on whether a Prudhoe Bay royalty gas sale should take place this spring. Revenue Commissioner Sterling Gallagher opposed the promotional contract sale because "it will be detrimental to the (Northwest) gas pipeline." Others suggested the state should wait for the outcome of the liquids pipeline study, expected to take about six months, before a decision is made.

Unlike last year when the legislature considered a royalty oil contract, which already had been awarded to ALPETCO after competition among a number of firms, LeResche had planned this year to initially send down only the structure of an unawarded contract. Bidding among prospective purchasers would take place later, if the legislature approved the contract and endorsed the concept of a sale. It is likely the contract would have to be approved by the legislature a second time after being awarded to the high bidder.

The draft contract prepared by the attorney general's office requires that the gas either be "processed or consumed" in Alaska. The buyer would have to "construct and operate, or cause to be constructed and operated, a facility for the in-state processing of the gas sold under this agreement."

The draft contract would sell 80 per cent of the Prudhoe Bay royalty gas for 20 years. The price for the gas would be at least the amount the state would have received by taking the gas in-value (in cash), and potential purchasers probably would bid a variable number of cents above the in-value floor. The administration is considering inclusion of a "franchise fee" either as a bid variable or as a fixed amount. LeResche said the state also would require an assignment fee if the option were sold to someone else.

In a January 19 letter to 17 prospective purchasers, LeResche said he had decided it was "unwise" to pursue the course detailed in the original solicitation circulated by the department last summer to 500 firms. Rather, LeResche said, he is "considering a more flexible approach to promote entrepreneurial pursuit of in-state use of our royalty gas."

Only 23 firms responded to the original solicitation, which tentatively set the sale for late March. The most recent solicitation was sent only to those firms that indicated an interest in using or processing the gas in Alaska.

"I would solicit your review of this draft (contract) and your comments on its principles, as well as any indication of whether your firm would be interested in pursuing something along these lines," LeResche's letter said.

The Fairbanks North Star Borough, one of the leading proponents of a royalty gas sale this year, said in a letter to LeResche it "strongly supports" the concept of a promotional contract.

"The borough would like to commend you for adopting this generalized contractual approach as a means of preventing the stagnation of interest in the state's royalty gas efforts, as well as insuring that federal decisions in Washington, D. C., not take the disposition of the gas out of the state's hands during the interim," Borough Mayor John Carlson said.

Carlson reiterated the borough's interest in assuring the availability of the gas liquids, and said he feared that the liquids would be used almost exclusively as boiler fuel at Prudhoe Bay to operate the gas conditioning plant. He urged the state to give notice of its intention to take its liquids and to negotiate with Atlantic Richfield, coordinator of the Parsons' study that outlined a design for the conditioning plant, to insure that the plan is redesigned to use less valuable fuel.

Carlson said ARCO is willing to redesign the conditioning plan to use other fuels if there is interest in buying the liquids. "Since the borough has received a proposal from Nissho-Iwai (of Japan), to purchase, in Fairbanks, as much as one million metric tons annually of propane and butane from Prudhoe Bay gas, we believe that there is strong potential interest in purchasing the liquids."

With regard to the price term of the contract, Carlson suggested that the state set the price at not less than the in-value floor, rather than having the price as a bid variable. He also suggested it might be appropriate for the state to accept less than the in-value price, "if it could be shown that the in-state sale of the royalty gas at less than in-value market prices elsewhere could insure increased state revenues and a sounder Alaskan economy through the creation of more diversified employment and business investment. It is not healthy for Alaska as a whole, nor the state government itself, if the state increases its direct revenues while major regions in the state are suffering economic distress."

When asked for his opinion on the advisability of selling the royalty gas to a promotional group this spring, Moore said, "In my judgment, you'll end up with another group like ALPETCO; you won't get a group with demonstrated competence, someone with money and markets. Is there a danger in this? Well, say ALPETCO fails. If it does fail, it will fail two years in the future and by that time, 10 per cent of the productive life of the field will be gone. By the time someone else gets a chance, it may be too late. This is sort of a one-shot approach...I just would not ever go with someone who didn't have significant financial resources and a proven track record in the industry, and that's going to be a major company. A major company won't be attracted unless the state enhances the firmness, the tangibility of its plans."

If the state were to develop a firm design, cost estimates and financial plans for a liquids pipeline, Moore said, it would "triple, quadruple or increase tenfold" the number of companies willing at least to seriously examine the feasibility of in-state development.

"I'm not optimistic that any small, promotional company will be successful in doing something with the liquids. It's a big boys' ballgame, and they keep the little guys out."

Even if the gas were sold this year to a promotional group, Moore said, developing firm plans for a liquids pipeline is still a good idea. "The promoters would have an easier time if you did that. It would make it easier all the way around."

VALDEZ EXPECTED TO WIN APPROVAL AS SITE FOR ALPETCO

Environmental Conservation Commissioner Ernst Mueller says he knows of no "insurmountable environmental problems" that would disqualify Valdez as the site for Alpetco's planned refinery and world-scale petrochemical facility.

Mueller, in a January 17 memorandum to Natural Resources Commissioner Robert LeResche, said that while much work remains to be done to secure approval of air and water discharge permits for the Alpetco facility, the only outstanding question is whether Alpetco can meet requirements of the "Prevention of Significant Deterioration" section of the Clean Air Act.

Mueller said that based on an evaluation of Alpetco's facility design and air monitoring reports, his staff has "concluded that Alpetco should be able to comply with all air quality requirements at the Valdez site provided that they use low-sulfur gas for process heat and power, and will be able to validate air quality models to show compliance with ambient air requirements. There is no reason to assume Alpetco will be unable to meet these provisions."

About 100 Valdez residents turned out for a public hearing January 29 to tell Commissioner LeResche that the town strongly supports the facility. Lennie Boston, a DNR staffer who attended the hearing, said the testimony in favor of Alpetco was "nearly unanimous."

LeResche, who must approve or disapprove Alpetco's selection of a site by March 6 under the contract approved by the legislature last year, has said he would approve Valdez if there were no major environmental problems and the people of the area wanted it.

Revenues

OPEC PRICE INCREASE BOOSTS STATE REVENUES

While the 14.5 per cent oil price hike adopted in December by the Organization of Petroleum Exporting Countries (OPEC) evoked mostly consternation in the rest of the country, the increase is good news for Alaska.

Under the federal pricing and entitlements structure, Alaska oil can be sold for the imported price.

An analysis conducted by Al Latham of the Legislative Affairs Agency Research Division estimates that state petroleum royalty and severance taxes will be $14 million higher in fiscal 1979 due to the increase, and that fiscal 1980 revenues will be $126 million higher.

The Research Division currently is conducting an analysis of revenue projections contained in the governor's budget.

ALASKA OIL PRICES EXPECTED TO RISE ON WEST AND GULF COASTS

North Slope producers, seeking to take advantage of the Iranian oil crisis, are attempting to boost by $1 a barrel the price of relatively heavy Alaska oil sold to West Coast big buyers under long-term contracts, an industry publication reports.

Petroleum Intelligence Weekly reported January 22 that the "walloping" increase is about 40¢ more than the basic OPEC "marker" jump of 63.5¢ and would put new prices for North Slope oil between $13.65 and $13.75 a barrel delivered, compared to between $12.65 and $12.85 previously.

However, West Coast buyers are resisting the big increase and threatening to cut volumes, PIW said, and "a compromise increase of about 80¢ is generally expected to develop--equal to the basic OPEC 63.5¢ marker rise with the extra 40¢ split in half to about 20¢."

Producers originally discounted North Slope oil by 40¢ to 60¢ relative to Arab light crude in efforts to place the maximum volume on the West Coast, PIW said, since their alternative was to ship it through the Panama Canal to the U.S. Gulf at an additional cost of about $2 a barrel.

Producers have run into little resistance on their U.S. Gulf Coast sales, PIW said, despite the same $1 increase there to about $14.30 a barrel delivered.

Battelle Northwest, in an analysis recently conducted for the legislature's interim West Coast Oil Surplus Committee, concluded that "contrary to popular belief, ANS crude oil, on a world average market basis, should be valued substantially on a par with the Saudi Arabian Light marker crude or possibly slightly higher."

Battelle said that the West Coast oil surplus has been depressing the North Slope crude price for refiners not purchasing their own oil by 70¢ to $1.60 a barrel. Battelle's analysis was developed by using multiple regression techniques on 32 crude oils to determine the most likely price the international market would be willing to pay for any particular crude participating in the world market on an unregulated basis.

The consultants concluded that North Slope oil, prior to the recent OPEC price increase, would have been selling for $13.87 ± 50¢ on the West Coast were it not for the surplus. Alaska oil is being discounted in the U.S. Gulf by about 69¢ a barrel, presumably because of competition from Mexican crude, Battelle said.

Gaining the right to export North Slope crude, which is financially the most attractive option for Alaska, "could eliminate all or a large portion of the current price discounting of ANS crude," the consultants said. "Exporting ANS crude via foreign ships would also result in a reduction in the demand for Jones Act (U.S. flag) tankers and a probable reduction in rates, depending upon volumes exported."

Exploration and Development

D-2 OUTCOME WILL AFFECT OIL EXPLORATION

Whether the Arctic Wildlife Range will be opened for oil exploration, or permanently reserved as wilderness, is certain to be a controversial topic as Congress grapples with resolving d-2.

The Arctic Wildlife Range, in the extreme northeast corner of the state, is considered by some one of the most promising oil prospects anywhere in the country.

Other than decontrol of crude oil prices, no other issues have more profound, long-term implications for the oil industry than access to resources and resolution of federal land withdrawals, industry spokesmen say.

Under the d-2 compromise bill that failed to pass Congress last fall, uplands in the Arctic Wildlife Range would have been wilderness, and the coastal plain area would have been opened to limited, carefully controlled exploration under management of the Interior Department. Congressional approval would have been required to develop any oil discovered during exploration.

HR 39 passed by the House last year, and the new version of HR 39 introduced this year, would designate the range as wilderness and preclude all development.

The status of the range, currently managed by Interior essentially as a wildlife refuge, was not changed by President Carter's order under the Antiquities Act that designated 56 million acres of Alaska lands as national monuments. If Congress does not pass a bill this year, it is believed the administration will take steps to insure that the area is managed as wilderness.

CARTER PROPOSES HALT TO EXPLORATION IN NPRA

President Carter wants to conclude the multi-million dollar federal oil exploration program in the National Petroleum Reserve in Alaska (NPRA) this September, a year ahead of schedule.

Carter's fiscal 1980 (October 1, 1979 to September 30, 1980) budget request recently submitted to Congress included only $4.4 million for NPRA exploration, just enough to pay for removal of men and machines. The Interior Department is spending more than $200 million in the current fiscal year under an exploration contract with Husky Oil; about $190 million was spent in fiscal 1978.

Although the federal government has been drilling intermittently in the reserve since 1944, and extensively since the Arab oil embargo of 1973, there have been no discoveries of commerical quantities of oil.

Responsibility for managing the reserve, which was created as a Naval Petroleum Reserve by executive order of President Harding in 1923, passed from the Navy to the Interior Department in 1977.

The federal government spent about $50 million during the decade between 1944 and 1953 drilling in the reserve. Several small oil and gas fields were found during that time, including the South Barrow Gas Field that supplies the village of Barrow and the Naval Arctic Research Laboratory. Carter's budget proposal would postpone further exploration and development of the Barrow area gas field "until a comprehensive study on alternative fuel supply and distribution systems is completed."

During the energy crisis of 1973, Congress launched a seven-year exploration program that was to cost between $600 million and $700 million. The goal of the program is to establish an information base to assist Congress in determining the best use of the 23 million acre area.

An Interior Department spokesman said the decision to end drilling this year stemmed from a legislative mandate to report to Congress on NPRA by January 1980. Therefore, any information gathered in 1980 would be too late for inclusion in the report.

By this September, a total of 19 exploratory wells will have been drilled in NPRA. Seven wells planned for fiscal 1980 will not be drilled if the President's proposal prevails in Congress.

Alaska Senator Ted Stevens criticized the Interior Department "for not living up to its commitment to explore the entire area for oil and gas," according to press reports. Stevens is expected to try to increase funding for exploration when the budget reaches the Senate Appropriations Committee.

An executive of Husky Oil, the prime contractor in the USGS exploration program, said that based on work the firm has done so far, "it would be a disservice to walk away or close the area up as a wilderness and not drill more in the future."

NPRA was once considered a highly prospective area that might contain as much as 33 billion to 100 billion barrels of oil. However, the latest USGS estimate of the reserve's potential is only one to three billion barrels.

KUPARUK FIELD TO BE DEVELOPED

The Atlantic Richfield Company has told state officials it wants to produce 80,000 barrels of oil a day from the Kuparuk field near Prudhoe Bay beginning in 1982.

Although the field is believed to have a total of 3.5 billion barrels of oil in place, the physical characteristics for production are poor and it is not expected that more than 15 per cent of the oil ultimately will be recovered.

The first 20 square mile portion of the field planned for development is owned 100 per cent by ARCO; ARCO and other companies own the remaining 47 square miles of the field, which may be developed in the mid-1980s.

An ARCO spokesman said a formal "go-ahead" has not yet been received from the company's corporate headquarters, but this approval is expected by April 1.

The company declined immediate comment on whether it plans to seek an increase in capacity of the Trans-Alaska oil pipeline to accommodate the additional production, or whether the Kuparuk oil would displace some of ARCO's and other companies' production from the main Sadlerochit reservoir.

COOK INLET GAS DISCOVERY ANNOUNCED

The Simasko Production Company has announced a "significant" new gas find about six miles south of Tyonek, a Native village on the west side of Cook Inlet.

Company President Don Simasko said the formation is thought to be of commercial quantity, although it will be several weeks before its size can be estimated, the Associated Press reported.

Simasko has been conducting exploratory drilling in the area for three and a half years in conjunction with its partner, Pacific Lighting Gas Development Co., of Los Angeles. Pacific Lighting's parent company is one of the major sponsors of the Pacific Alaska LNG project, which would liquify gas from 19 Cook Inlet fields at a Nikiski plant for export to Southern California. The project has not yet received federal approval.

A Pacific Lighting spokesman said Simasko's characterization of the find "may be a bit too optimistic."

Other

MEXICAN OIL AND GAS ARE COMPETITION FOR ALASKA

The new oil and gas finds in Mexico represent major competition for Alaska's resources, a Congressional Research Service study says.

Mexican oil is expected to displace Alaska oil in the U.S. Gulf, and Mexican gas (if Mexico can be persuaded to sell it) probably would be much cheaper for Lower 48 consumers than Alaska gas brought by pipeline from the Arctic, the study said.

To the United States, the new Mexican oil represents an attractive alternative to imported OPEC oil, and the Mexican gas is cheaper than developing other "supplemental" supplies now under consideration, such as SNG, LNG and the Alaska pipeline.

Even though the United States is a natural customer for Mexico, many predict the U.S. will have to redefine its traditionally dominant relationship with the emerging power on its southern border if it wants a secure, long-term supply of Mexican oil and gas. This may include more economic aid to Mexico, lower trade barriers on imports of Mexican textiles and produce, and a reversal of present moves toward stringent immigration controls.

While not all experts agree on the potential size of Mexico's resource base (see The Christian Science Monitor, December 4, for a pessimistic view), the predominant view is that Mexico sits on an enormous, largely unexplored sea of oil and gas. By one account, there may be enough petroleum in Mexico to supply all U.S. energy needs for 40 years at current rates of consumption.

"Intensive exploration in Mexico is turning up oil fields so immense that they could overturn the conventional wisdom about world oil supplies and significantly alter the geopolitics of energy," Science magazine reported December 22.

The numbers of "proved," "probable," and "possible" hydrocarbon reserves -- which have been revised steadily upward by Mexico for several years -- are large indeed. The Mexican government at year-end announced still another increase, setting proved reserves (based on actual drilling and development) at 40.2 billion barrels, with an additional 44.6 billion barrels probable. Total possible reserves were set at 200 billion barrels. (These figures include both oil and gas; about two-thirds are oil, one-third gas.) In contrast, the "super giant" Prudhoe Bay field has proved oil reserves of about 9.7 billion barrels, while Saudi Arabia has proved reserves of about 150 billion barrels.

According to the December 6 Congressional Research Service (CRS) report, "Mexico's Oil and Gas Policy: An Analysis," Mexico appears to have a lot of oil and gas, but "the true yield from discoveries beyond the proven reserve estimates will remain somewhat unknown until more developmental drilling takes place." Current indications, CRS said, "are that a significant hydrocarbon resource is present, perhaps in the 30 to 50 billion barrel range with the possibility of even a large amount."

One result of the large Mexican discoveries may be a reassessment of the fundamental notions underlying U.S. energy policy.

The dual premises of U.S. energy policy, as first articulated by the Nixon-Ford administrations after the 1973-74 embargo and upheaval in oil prices, are that the world is running out of energy and that the nation must curb its ravenous appetite for imported oil.

It was in the context of this widely held belief that Congress and present and past administrations decided the nation needed an expensive pipeline to transport Prudhoe Bay gas to the Lower 48.

The prospect that some of the world's richest oil fields may lie next door in a relatively friendly, non-OPEC country seems likely to further undermine President Carter's vision of an energy crisis so serious and so imminent that it requires a response amounting to the "moral equivalent of war."

The New Republic reported in August that the CIA alerted Ford administration officials to the scale of the Mexican discoveries in 1976, more than a year before they were made public, but that both Ford and Carter ignored them in shaping energy policy because public opinion would have turned even more deaf to energy-crisis rhetoric than it already had.

Now that the administration's energy program finally has passed Congress, most signs indicate that President Carter is about to launch a campaign to secure long-term supplies to Mexican oil and gas, beginning with his visit to Mexico in mid-February.

However, the administration still is maintaining staunch public support for the Alaska gas line project, and it has placed acquisition of Mexican and Canadian supplies below all domestic sources, including Alaska gas, in its list of priorities.

At a January news conference, Carter said that there is "no short-term urgency about acquiring Mexican natural gas" because "we have at this moment a surplus of natural gas in our own country." The President observed that the Mexicans are "very independent regarding their decision on how rapidly to produce their gas and oil," and "we would not try to encroach on this independence, nor try to encourage them to more rapidly produce gas and oil than they themselves desire."

One of the President's first problems during his February visit will be to untangle the embarrassing loose ends from the natural gas sale killed early last year by Energy Secretary Schlesinger. It is widely perceived that the administration badly bungled the proposed sale of Mexican gas to six U.S. distributors at a price of $2.60 per thousand cubic feet (mcf).

Petroleos Mexicanos (PEMEX), the national oil company, had signed a letter of intent to sell the gas and had nearly completed construction on a pipeline that was to stretch from Cactus in southeast Mexico to Reynosa just south of the Texas border.

But the Carter administration refused to approve the sale, arguing the U.S. could not pay Mexico 44¢ per mcf more than it was paying for Canadian imports ($2.16/mcf). The administration also was not eager to point out the fact that its energy bill limited gas prices for U.S. producers to considerably less than Mexico was asking.

"When compared to future supplemental gas supplies available to the U.S. in the 1980's, such as Canadian imports, synthetic natural gas with naptha as a feedstock, Alaskan gas and coal gasification gas, Mexican gas appears to offer the greatest supply potential at a price with which only Canadian imports can compete," the CRS study said. "However, the political consequences surrounding the abrupt termination of natural gas negotiations in early 1978 between PEMEX and six U.S. natural gas pipelines has made future U.S. access to Mexican gas highly uncertain."

Since the gas negotiations ended, Mexico has announced it no longer intends to export its gas to the U.S. but instead will create a nationwide distribution network to use the gas in Mexico. The U.S. refusal to accept the $2.60 price, which was based on the world oil price and calculated in terms of the Btu value of No. 2 heating oil delivered to New York, reportedly was extremely embarrassing to Mexican President Lopez Portillo and created strong political opposition in Mexico toward any hydrocarbon exports to the United States. "The idea that Mexico should tighten its belt and sell off its resources to the United States for less than the world price resulted in nationalistic outrage, particularly in view of the history of petroleum relations between the two countries," Science magazine said.

But if President Carter, who has been taking Spanish lessons for some time, is successful in smoothing relations and reopening the gas negotiations, and if agreement on a sales price ultimately is reached, the Alaska gas pipeline project could become even more uncertain.

The CRS report gives the following "reasonable estimates of supplemental gas source prices" and predicts that Alaska gas will be among the most expensive alternatives:

1985 SUPPLEMENTAL GAS PRICES (1985 dollars)

	PEMEX 1/	CANADIAN GAS 2/	SNG COAL 3/	SNG OIL 4/	ALASKA GAS 3/	LNG 5/
1985	$4.14	$3.56-5.14	$7.32-8.04	$5.00-6.75	$5.58-6.30	$5.15

1/ Assume 6 per cent annual increase in No. 2 fuel oil price.

2/ CRS estimate based on Canadian and U.S. gas pricing policy.

3/ Prices for SNG coal and Alaskan gas from DOE intervention before FERC, ANG Coal Gasification Company proceeding, FERC Docket Nos. CP75-278, et al. June 1, 1978, p.5.

4/ Estimate assumes naptha as the feedstock and is based upon conversation with Bill Norman, J. Makowski, Associates, Boston, Mass.

5/ Tenneco Atlantic Algerian project.

The export of Mexican crude oil on a large scale -- at this point considered more likely than gas exports -- also could have an impact on Alaska.

"Mexican oil will almost certainly displace a large amount of Persian Gulf oil and could displace some Alaskan oil on both the Gulf and Pacific Coasts of the United States," the CRS report said. "This could present a serious problem to Alaskan North Slope producers who have no export option and who need substantial sales in both markets in order to maintain production and pipeline throughput levels. Faced with large sunk costs and no real alternatives other than 'shutting in' capacity, these producers will probably discount Alaskan oil to whatever level is necessary to undersell Mexican oil and to maintain their market shares."

The CRS report also said the prospect of possible sales of Mexican oil on the U.S. West Coast "may aggravate the existing surplus there."

Compared to Mexican crude, North Slope oil is worth 38¢ a barrel less solely because of its lower quality.

Mexican crude is now discounted on the U.S. Gulf in order to displace Saudi light crude, the CRS report said, and this lower cost of Mexican oil already is causing North Slope crude to be further discounted by 29¢ to 58¢ per barrel in the U.S. Gulf (not counting the 38¢ quality discount). By 1985, the report said, the discount on Alaska oil in the Gulf could amount to 64¢ to $1.28 per barrel, even if the proposed Sohio pipeline from Long Beach, California, to Midland, Texas is built.

"Mexico will probably price its oil just low enough to back out Saudi light, but not low enough to displace ANS (Alaska North Slope) crude on a large scale (at the Gulf)," the report said.

By the 1990's, there's going to be a lot of Mexican oil available in the U.S. Gulf, which "will place heavy competitive pressures on all other foreign sour crude oil. If shipments of ANS crude to the Gulf Coast were reduced as a result, then the throughput of the PACTEX Pipeline (Sohio pipeline) could drop below 500,000 b/d by 1985. This could mean consequent increases in PACTEX tariffs or lead to further discounts in the price of ANS crude oil to make it competitive," the CRS report said.

"The net effect, therefore, could be one of either discouraging domestic production, especially in Alaska, or of reducing the profitability of North Slope operations," the CRS report concluded.

HAMMOND REQUESTS SUSITNA APPROPRIATION

Despite the tight state budget and general cash crunch, Governor Hammond has asked the legislature to appropriate $8.1 million to provide guarantees for studies on the Susitna hydroelectric project.

The legislature last session passed a resolution authorizing the Alaska Power Authority to sell bonds to complete a four-year, $25 million "Phase I" study, but the authorization was made contingent on passage of federal legislation that would reimburse the authority with federal funds if the project turned out to be infeasible. This legislation failed to pass Congress.

Although Senator Gravel intends to resubmit the proposal to Congress this year, it is still necessary to consider other interim financing alternatives because federal authorization would come too late to do geological, biological and engineering tests during the 1979 summer season, the governor said in a letter accompanying his proposals, SB 63 and SJR 6.

"The possibility of a one-year delay must be carefully weighed along with the many uncertainties surrounding a project which I believe will prove to meet the three pertinent criteria by which all such projects should be adjudged; is it environmentally acceptable, economically feasible and do the majority of the people desire it," the governor said.

Hammond said positive action on the appropriation is needed by mid-February in order for the Corps of Engineers to mobilize contractors and move equipment to the study sites before breakup.

"Due to the obvious complexity of the situation, including the possibility of complete State financing of the entire $25 million study effort should the Congress fail to adopt Senator Gravel's proposal, I request that you take the earliest opportunity to consider this appropriation and its companion resolution in order to satisfy yourselves that this is the proper way to proceed on this project," the governor said in his January 18 letter.

The Phase I study will address the environmental, economic, social and engineering feasibility of the massive project, which would involve construction of two dams on the Susitna River and 365 miles of transmission line. The project is now estimated to cost about $2.7 billion.

KELSO DESCRIBES PLAN TO BROADEN CAPITAL OWNERSHIP

Louis Kelso, the maverick investment banker who wants to make ordinary people rich, will soon unveil a capital diffusion plan for Alaska that, if adopted, "will be a model for other states and for every developing economy in the world."

Kelso told a group of legislators recently he recommended a similar plan to the Shah of Iran 10 years ago. "If he had followed my advice, he'd still be in power today," he said.

Kelso's recommendations for the economic and operating structure of an Alaska General Stock Ownership Corporation (AGSOC) will be made in a written report to the legislature February 15. Authorization to make the profits of an AGSOC exempt from federal corporate income taxation was granted by Congress last fall at the urging of Senator Mike Gravel.

Kelso, who met with legislators in Juneau January 25 to get "policy guidance" on the AGSOC's structure, outlined restrictions imposed by the federal law and said he thinks the restraints "are ones that the State of Alaska would favor."

The new federal law allows states to establish private corporations for the benefit of their citizens. These corporations, if they meet certain requirements, will not be subject to federal income tax. Instead, the shareholders of the corporation, which must include every qualified resident of the state who chooses to participate, will be taxed on their daily pro rata shares of the corporation's taxable income.

Restraints imposed by federal law include:

-- Shares of the corporation's stock can't be transferred for five years after their original issue unless the owner dies or moves out of the state. Kelso said he would recommend that the stock be held in escrow during the first five years.

-- No one individual can own more than 10 shares of stock.

-- At least 90 percent of the corporation's income not used for corporate operating expenses must be distributed to shareholders each year.

-- All residents of the state are entitled to a stock interest in the corporation, but they must be residents at the time the AGSOC is chartered (a date to be set by the legislature) and must remain residents until stock is issued. Kelso said Attorney General Avrum Gross is attempting to develop a definition of "resident" that will withstand constitutional challenge, but "there is no way to define it so that sooner or later a court suit won't arise."

Kelso also outlined a number of policy questions that the legislature will have to address:

-- At what age should the citizen stockholders be allowed to vote their stock? Should children be allowed to vote, or should their parents be allowed to vote for them? Kelso said he thinks it is most sensible to specify that stock would not be voted until the shareholder reaches 19, Alaska's age of majority.

-- Should an individual be required to sell his stock if he leaves the state, and if so, at what price and under what terms?

-- How should the management of the corporation be structured? Kelso said he would recommend a nine-member Board of Directors, at least five of whom would have to be Alaska residents, to be initially appointed by the governor to staggered one-, two- and three-year terms and elected thereafter by stockholders to three-year terms.

-- How should the transfer of stock be handled? Kelso said he would recommend that the corporation set up its own stock transfer department; the other alternative would be to do it through a bank.

-- How will the corporation get money for the start-up costs of hiring management, getting legal advice, and investigating investment possibilities? Kelso said between \$3 million and \$5 million would be needed for start-up costs, and the money could come from either a state grant or loan or a bank loan guaranteed by the state. Kelso said he prefers loans over grants because "this is intended to be a private enterprise, to pay all its costs, to stand on its own feet."

-- How will the corporation get the billions of dollars needed to invest in large projects? ("The AGSOC is designed for big projects," Kelso said. "If it took on little projects, the income would be of no significance.") Using "project financing" techniques, the AGSOC would be able to borrow from conventional lending sources, although it would have to acquire a sizeable chunk of money in equity first. The equity could be loaned by the state, or the state could guarantee an equity loan. If the loan by the state comes from a state bond issue, or if the guarantee is an unfunded liability (as opposed to appropriation of a reserve), voter approval by referendum would be required.

-- What project or projects should the AGSOC invest in? Kelso said his firm had studied one investment possibility, the Trans-Alaska oil pipeline, which "looked quite feasible." According to press reports, Senator Gravel's staff has calculated that an AGSOC purchase of British Petroleum's 16 percent interest in TAPS would generate enough earnings to pay expenses and debts and send about \$390 to every Alaskan.

Kelso and others point out that even though the federal law allows GSOC's to include only residents of the state and exclude future new residents, the plan may face constitutional challenges.

An analysis conducted by the Washington, D.C., law firm of Wilmer, Cutler & Pickering for the state Department of Revenue concludes: "In light of the history of constitutional challenges to a number of Alaskan laws that have treated residents more favorably than non-residents, an eventual constitutional challenge to the state's creation of a GSOC would not be unexpected." However, the consultants said, the plan can be structured in a way "that will minimize the possibility of success of any constitutional challenge," but a favorable result cannot be guaranteed.

The analysis said the most difficult problem with the GSOC is its "closed class" feature, which limits ownership to residents on a certain date and precludes persons who later qualify as residents from becoming shareholders.

Kelso suggested that one solution might be to allow new residents to purchase AGSOC stock at book value after a two-year waiting period.

Kelso is under contract with the Legislative Finance Division and the legislature's Joint Gas Pipeline Financing Committee.

HAMMOND APPOINTS OIL AND GAS CONSERVATION COMMISSIONERS

Three current state employees were recently appointed by Governor Hammond to serve on the new Alaska Oil and Gas Conservation Commission, which was created by the legislature last session.

Hoyle Hamilton, formerly director of the Division of Oil and Gas in the Department of Natural Resources, was named chairman of the commission. Lonnie Smith, formerly chief petroleum engineer for the division, and Harry Kugler, formerly chief petroleum geologist for the division, were named as the other two commissioners.

The new commission is an independent, quasi judicial body that has assumed the division's responsibility of administering the state conservation statute. Its duties include preventing the waste of oil and gas, protecting the rights of lease holders, and issuing drilling permits on all state lands.

The commission began operation January 1.

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HALLORAN

STATE OF ALASKA
THE LEGISLATURE

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LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

No. 5 April 16, 1979

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-- Compiled by Kay Brown, Policy Analyst --

OIL SWAP PROSPECTS SUFFER SETBACKS

Legislators and Natural Resources Commissioner Robert LeResche have agreed to postpone temporarily a congressional lobbying campaign for the three-way royalty oil swap with Mexico and Japan, saying they will "keep a low profile" while Congress debates a proposed extension of the McKinney amendment.

House and Senate leaders met with administration officials April 10 to discuss recent setbacks in the state's attempt to convince President Carter, the Congress and the country that foreign exchanges of Alaska royalty oil are in the national interest and should be permitted.

Representative Stewart McKinney, a Republican from Connecticut, recently introduced legislation to extend indefinitely the restriction on exporting Alaska oil and reduce the already limited circumstances under which the President could seek congressional approval for the export of domestic oil. McKinney authored the current law severely restricting exports, which will expire June 22.

LeResche and legislative consultant Arlon Tussing said Sohio's tentative abandonment of its west-to-east pipeline and the Iranian revolution have set back the state's efforts by at least six months. October is about the earliest that President Carter might propose the swap to Congress, Tussing said.

"Were it not for two things, we'd be at the point of conducting a massive congressional lobbying campaign. One of those things is the Iranian revolution, which has put the whole world oil market in turmoil and made it practically impossible for us to negotiate a swap with Mexico, because the terms keep changing all the time," Tussing said. "The Mexicans don't know how much they can get in a straight sale to Japan, so how do we structure a swap until these things settle down? Mexico thinks right now it can get $17.10 a barrel in straight sales to the United States. In that context, why would they bother going through the swap?"

If Mexico is able to get $17.10 a barrel in the U.S. Gulf, then the state should be able to get $3 a barrel more for Alaska oil sold in Japan, Tussing said, "and the swap makes the same sense as it did before."

On April 4, Mexico boosted its oil price by $3 a barrel, a 21 percent increase.

Sohio's abandonment of the PACTEX pipeline has had a negative impact on the swap's chances of winning congressional approval, Tussing said, as well as prompting "a flurry of cheap-shot demagoguery" and renewed expressions of patriotic desire for energy self-sufficiency.

"Right now I would judge that this is not the time for us to make waves with a unilateral assault on the sensibilities of Congress by trying to go ahead with a backdoor export, or trying to use some loophole in the law, or going to court," Tussing said.

Randall Moen, an attorney for the legislature's joint gas pipeline committee, urged the state to take more aggressive action by pursuing an exception in federal law that allows exchanges with the "adjacent foreign states" of Canada and Mexico. The state should complete negotiations on a swap with Mexico and Japan, apply to the Department of Commerce for an export license under the "adjacent foreign states" exception, and file suit against the government when it's rejected, Moen said. The Commerce Department interprets an adjacent nation exchange as one with "Mexico or Canada for consumption therein," Moen said, "which would preclude Alaska from any paper transaction with Mexico or Japan."

Nevertheless, Moen said, "it seems to me that if we are to be successful in the oil swap problem we must take the initiative by seeking relief through the courts, through Congress, through the President, through the Department of Commerce and Mexico. There are many ways to go about this, and we should use all means possible."

LeResche said that if the state attempts to take legal action under the "adjacent nation" exception, a restrictive version of the McKinney amendment closing the loophole is likely to become law.

Although the legislators eventually agreed to accept Tussing's low-profile strategy, several expressed concern over whether enough was being done.

"With Alpetco having a call on the oil in July of 1980, aren't we just kidding ouselves?" asked Representative Bill Miles. "Haven't we dropped the ball?"

Tussing responded that the "chances of Alpetco actually being eligible to purchase oil at that time are relatively small." Even if Alpetco does meet the requirements of its contract, he said, "it would be happy to step into the state's shoes on the swap."

Senator Bill Sumner said the state is losing $100,000 a day because of the West Coast surplus, and "I'm getting the feeling that not enough is being done."

Assistant Attorney General Bob Maynard, who has assisted LeResche in negotiations with Mexico, said it is unclear whether the Mexico-Japan swap is still economically attractive for the state. Superior Court

Judge Compton's royalty oil decision means that the market must make up the difference in field charges the state will have to pay if it takes the oil in kind, Maynard said. (See page 9.)

Representative Chat Chatterton suggested the state investigate the possibility of purchasing producer oil for use in the swap to bypass this problem.

Senator Mike Colletta said he was "willing to concede that this is not the right time" to push ahead with an all-out lobbying campaign, "but in three or four months you've got to take positive action."

Tussing said he would investigate "new directions, other options," including the possibilities of swaps involving Israel and Canada, as well as continuing a "soft sell" in Congress on the state's position.

LeResche said the administration would meet with Pemex, the Mexican national oil company, at least one more time to see of the swap could be restructured under the new market conditions.

Although prospects for the swap looked promising when President Carter visited Mexico in February, congressional opposition has recently become more vocal.

Senator Henry Jackson of Washington, chairman of the Senate Energy and Natural Resources Committee and formerly a supporter of the swap, told a press conference in Seattle March 23 that the Alaska-Japan-Mexico oil swap is unlikely to win approval. "It's clear that it's not politically feasible. The Senate would not grant a waiver to the President for a swap," the Seattle Post-Intelligencer quoted Jackson as saying.

The Department of Energy has continued to express support for the swap before Congressional committees, and President Carter urged Congress to let the McKinney amendment expire June 22 in the background paper of his recent energy message, according to press reports.

MCKINNEY MAKES CASE AGAINST EXPORTS

Representative Stewart McKinney says the Prudhoe Bay oil producers have intended all along to export Alaska oil to Japan, and he's determined to stop them.

McKinney urged the Subcommittee on International Economic Policy and Trade of the House Committee on Foreign Affairs March 21 "to move this country farther down the road of self sufficiency by asking that the commitments made to this Congress in 1973 are commitments kept to this country in 1979."

The oil companies "are guilty of a breach of the promise to develop a domestic distribution system for Alaskan oil," he said. McKinney also told the subcommittee that:

- Sohio's decision to cancel the PACTEX pipeline is only further evidence of the long-term intent of the North Slope producers to force exports to Japan.

- The federal government should take action forcing the oil companies to make the necessary investments to convert from processing low sulfur Iranian oil to relatively high sulfur Alaskan oil.

- In the short run, surplus Alaskan oil should be stored in the U.S. Strategic Petroleum Reserve until such refinery capacity becomes available.

- To the extent that treaty commitments exist between the United States and other countries, like Israel, exports of Alaskan oil should be permitted.

- "What would be the attitude of the constituents of the members of this subcommittee if they saw foreign flag tankers carrying Alaskan crude oil to Japan while at the same time gas stations in their communities were closed on Sunday?"

Converse Hettinger, director of the Short Supply Division, Office of Export Administration of the Bureau of Trade Regulation, Department of Commerce, said:

- It is not clear whether short-term Alaska oil exports would discourage construction of the Sohio pipeline.

- The Commerce Department believes a rigid policy banning exports could operate as a long-term disincentive for production and exploration on the North Slope.

Assistant Attorney General Robert Maynard, appearing on behalf of the State of Alaska, told the subcommittee that:

- Of the numerous restrictions on exports in current law, the state has a problem with only one, which is contained in the McKinney amendment. "The exchange we are arranging can meet this standard, but we feel it is unduly restrictive nonetheless. We oppose the requirement that an export will have a positive effect on consumer oil prices by decreasing the average crude oil acquisition costs of refiners."

- Recognizing the political problems of explaining exports to the American people in a time of oil shortage, the state is not suggesting a repeal of all export restrictions, or even a major change in existing export requirements. "We are simply advocating the beginning of a step in a direction that all seem to recognize as being in the real interest of the United States--even though it is one that public perception may not fully comprehend. We are simply asking for a relaxation of export restrictions, and the perfect opportunity is in the scheduled demise of the McKinney amendment."

Alvin Alm, assistant secretary for Policy and Evaluation, Department of Energy, told the subcommittee that the proposed McKinney amendment unnecessarily inhibits the ability of the President to make decisions in response to the energy needs and requirements of the country.

Gerald Rosen, director of the Office of Fuels and Energy, State Department, seconded that view, saying that because of international treaty provisions, such as the Sinai II Agreement with Israel and the International Energy Agency, the administration prefers minimal legislative restrictions on the President's authority to permit the export of domestic oil and consequently opposes the McKinney amendment.

SOHIO PULLS OUT

Standard Oil Co. of Ohio, the only major North Slope producer unable to sell the bulk of its Alaska production on the West Coast, apparently will not build its proposed oil pipeline from California to Texas.

Sohio officials say there is only a slim chance the project will be revived. Sohio Chairman Alton W. Whitehouse, Jr., said a "miracle" would be needed to save it.

President Carter proposed legislation to expedite the project in his national energy address April 5. Representative John Dingell, D-Mich., and Representative Morris Udall, D-Ariz., already had proposed a law that would allow Congress to pre-empt certain state and federal laws delaying the project, upon a recommendation from the president.

Whitehouse said Sohio was willing "to provide constructive assistance" for a few months "to see whether government can finally clear the way for the project to begin." But he said he doubted the Congress would pass legislation overriding California law; even if such a law could be passed, it probably could not be done in time to save PACTEX. The California legislature is unlikely to exempt the project from existing environmental laws, Whitehouse said.

"If somebody works a miracle--if lightning strikes quickly--and answers the difficult problems which remain, Sohio will reexamine the project," Whitehouse told congressional committees April 2. "But time and economics are running against all of us."

Sohio announced March 13 it would abandon PACTEX after spending four and a half years and more than $50 million trying to get approval, because of endless regulatory delays, pending and threatened litigation and erosion of the project's once-attractive economics.

The $1 billion project would have moved Alaska oil more than 1,000 miles inland from Long Beach to Midland, Texas; it was considered the leading contender among all proposals for long-term resolution of the West Coast oil surplus.

Sohio said its principal reasons for abandoning the project were:

Economic--If the pipeline had been operating in 1978, as originally projected, it would have had a cumulative throughput equal to all the surplus Alaska oil on the West Coast. After mid-1982, the remaining surplus to be moved through the line would have decreased to a level insufficient to support the economics of pipeline investment. Additional delays from litigation and obtaining final permits have pushed the startup date back to 1983.

In response to questions from Senator Henry Jackson, D-Wash., Sohio projected its 1982 North Slope wellhead netback at $6.98 for oil shipped to the U.S. Gulf Coast through the Panama Canal, compared to a wellhead netback of $7.48 for oil delivered to the Gulf Coast through PACTEX. The company said it currently has a North Slope wellhead netback of $6.01 for West Coast sales, and a $4.02 wellhead netback for oil shipped through the Panama Canal. (Figures obtained by the Legislative Affairs Agency Research Division show an average February North Slope netback of $4.56 for oil moved through the Panama Canal.)

Inflation in the cost of the pipeline and terminal due to delay also adversely affected the project's economics.

Permitting delays--After more than four years of work, Sohio was unable to obtain all of the more than 700 state and federal permits required. Almost all of the remaining unresolved questions involved environmental reviews and approvals by California state agencies. "The complexity of the issues, the number of agencies involved, and the procedural requirements of law, gave rise to a lurking fear that a final answer could not be achieved, or what is more important, that it would be impossible to predict how long it will take to secure a final answer," the company said.

Litigation--Without pre-emptive California legislation, extensive time-consuming litigation was assured. Three cases already are pending in the California courts. These suits challenge the adequacy of the basic project Environmental Impact Report (required by the California Environmental Quality Act), the approval of the California Public Utilities Commission to convert part of a natural gas pipeline into the oil line, and the validity of the Port of Long Beach lease with Sohio.

Even if expediting legislation proposed by Sohio to the California legislature were passed, litigation challenging the legislation itself or actions of various California agencies pursuant to that legislation had to be expected, Sohio said. "We have been informed a number of times by several different persons of their intent to pursue legal action against this project at every possible juncture," Sohio said.

Gas pipeline availability--PACTEX would use two existing, unneeded natural gas pipelines owned by El Paso Natural Gas Co. and Southern California Gas Co. "We have recently been informed by a gas transmission company that natural gas production in the Southwest United States is not declining at expected rates, that current Canadian natural gas supplies could further increase the availability of natural gas in the Southwest and that additional supplies of natural gas may become available from Mexico. Sohio has no knowledge itself about the correctness of this assessment," Whitehouse said. The possibility the gas pipelines might be needed for gas is yet another issue that might be used to sidetrack resolution of the remaining problems.

Legislative solutions--Pre-emptive legislation overriding California environmental laws is unlikely to pass either the California legislature or Congress, the company said.

INTERIOR EVALUATES ENVIRONMENTAL IMPACTS OF PIPELINE PROPOSALS

The Department of Interior's Bureau of Land Management (BLM) is completing an Environmental Impact Statement on a number of oil pipeline proposals for moving Alaska oil eastward.

The bulk of work on the draft environmental analysis, which was reviewed at a series of public hearings in the Northwest and in Alaska this spring, relates specifically to the Northern Tier Pipeline proposal. The final EIS will be broadened significantly to include an environmental assessment of the Northwest Energy-Foothills Skagway-to-Alberta proposal, the Kitimat proposal, and the Trans Mountain Pipeline reversal, a BLM spokesman said at a public hearing in Juneau March 19.

A new law passed last fall as part of the national energy program established an expedited procedure for presidential selection of one or more of the competing oil pipelines; the law required that Environmental Impact Statements on the proposals be completed by December 1, 1978. BLM was unable to meet that deadline, but it is expediting all oil pipeline applications.

Once the EIS process is completed, the Secretary of the Interior will recommend to the President which of the pipelines should be built. The President will choose. Once a pipeline is selected, the new law provides for expedited action an all federal permits, licenses and approvals for construction and operation of the system.

Most testimony at BLM's Alaska hearings on the Northern Tier draft EIS related to the Northwest Energy-Foothills proposal for a major oil port at Skagway and pipeline to Alberta. The reaction from Juneau residents was mostly negative; fishermen, conservation groups and the U.S. National Park Service questioned whether oil tankers could operate safely in Southeast Alaska waters without harming fisheries. Testimony at a March 20 hearing in Skagway was mostly positive; local residents emphasized the benefits of new jobs from construction and operation of the oil port.

Revenues

OIL REVENUE PROJECTIONS RISE

Projections of Alaska's oil and gas revenue released simultaneously on March 27 by the Department of Revenue and the Legislative Affairs Agency's Research Division both show sharp increases in fiscal year (FY) 1980.

The agency estimates that FY 1980 revenues will be about $190 million dollars more than had been estimated in January by the Department of Revenue. The Department of Revenue's March estimate shows an increase of only $90 million dollars for FY 1980. The increases are attributable principally to expected increases in pipeline throughput (from 1.19 million barrels per day to 1.35 million barrels per day) and to rising oil prices associated with the disruption of Iranian oil production.

In memoranda accompanying the estimates both the agency and the Department of Revenue emphasized the great uncertainties surrounding oil revenue projections. For example, actual FY '80 revenues could be as much as $372 million dollars higher than the January estimates if the state should get favorable rulings on the TAPS tariff and royalty pricing cases currently pending, the agency said. On April 9 the state did receive a favorable ruling on its royalty suit, but state attorneys say the matter almost certainly will be appealed.

Both the agency and the Department of Revenue said unfavorable regulatory actions or natural disasters conceivably could reduce oil revenues to levels below those estimated in January.

"The currently optimistic outlook really represents no fundamental change in the state's long-term financial position. It remains our view and the view of almost all responsible parties who have studied the issue that the 'hard landing' occasioned by the eventual loss of Prudhoe Bay revenues remains a crucial problem for Alaska," the agency said.

Copies of the revenue projections issued March 27 by the Department of Revenue and the agency are available in the Research Division's office.

STATE WINS VICTORY IN ROYALTY SUIT

State Superior Court Judge Allen Compton has ruled that North Slope producers cannot charge the state for treatment and cleaning of royalty oil and gas taken in value.

The decision, issued April 9, will mean $1 billion to $1.3 billion in oil revenues alone to the state over the life of the Prudhoe Bay field if Compton's ruling is upheld on appeal. Field charges amount to $1.11 a barrel. Under an interim agreement pending settlement of the suit, the companies have been charging the state an average of 64 cents per barrel for field expenses.

The state filed the suit in September, 1977, to resolve a dispute between the state oil and gas leasing laws and the actual language of the leases.

The state argued that the Alaska Constitution and state law require that its 12½ percent royalty share be valued as oil enters the Lease Automatic Custody Transfer Meter (LACT) of the TAPS pipeline. The statute says the royalty "shall not be less than 12½ percent in amount or value of the production removed or sold from the lease." The state contended that "production" has not occurred until the oil is in marketable form, which is at the LACT meter.

The oil companies contended that the legislature delegated the authority to determine the method of valuing royalty payments to the Commissioner of Natural Resources, who exercised that authority when the leases were sold. The leases say royalties are to be valued "at the well" if taken "in value," and the companies say that means somewhere in the field before the oil has been treated.

Compton said federal court decisions support the state's contention that oil and gas cannot be deemed "produced" within the meaning of the law until the oil and gas is in marketable form. He also said the Alaska Constitution clearly states that the state's resources should be developed "to provide the maximum benefit to the citizens of the State."

If the state takes its royalty oil "in kind," however, the companies are allowed to charge the state for "cleaning and dehydrating," which is specifically authorized in the leases, Compton said.

"However, pursuant to Constitutional mandate, the State may not take royalty 'in kind' unless, after said deductions, it will be in the best interests of the State to do so, which presumably means that it will be receiving an amount at least as great as it would if the royalty was taken 'in value.' This is the only interpretation which would comport with the Constitutional requirement that the legislature develop the natural resources 'for the maximum benefit of its people,'" Compton said.

The Alpetco contract with the state for the purchase of Prudhoe Bay royalty oil specifically states that Alpetco will pay the "in value" price for oil and will reimburse the state for any costs incurred by the state solely because it took the oil in kind.

Compton's decision also applied to gas royalties, but the effect on the allocation of conditioning costs is not yet clear. Compton held that producers will have to bear all costs incurred prior to the gas entering the functional equivalent of the LACT meter into the Trans-Alaska pipeline.

Compton's decision on field costs affects roughly half the money at stake in the royalty suit. The calculation of tanker charges and other "downstream" issues have not yet been decided.

STATE AUDITS TANKER CHARGES

A study of tanker transportation economics by Martingale, Inc., indicates artificial inflation of the tanker charges claimed by some North Slope oil producers, Petroleum Revenue Director Tom Williams says.

The Petroleum Revenue Division has begun new audits of the oil companies' books as a result of the Martingale study, which was released in March.

"With respect to some of the companies, this will put their feet to the fire because they've claimed substantially higher costs than are indicated in Martingale," Williams said. "The differences are small for some companies, but there are some major differences. This puts the burden on the companies to document their costs and to rebut Martingale. They will in the course of this audit have the opportunity to come forward with evidence and supporting documents, and I don't want to prejudge their arguments."

The tanker charges for moving Prudhoe Bay oil from Valdez to the U.S. West and Gulf coasts affect the wellhead value of the oil, on which state royalties and severance taxes are based. The wellhead value is computed by subtracting the pipeline tariff, field charges and tanker charges from the destination sales price of the oil.

Whether the tanker charges claimed by the companies are too high will eventually be litigated as part of the state's royalty suit against the companies, now pending in state Superior Court.

The Martingale study, prepared for the legislature and the Department of Revenue at a cost of $68,400, examines and estimates the costs for a variety of tanker arrangements used by North Slope producers for moving Prudhoe Bay oil to market.

OIL COMPANIES SUE STATE OVER CORPORATE INCOME TAX HIKE

The major North Slope oil producers, with the notable exception of Exxon, and their pipeline affiliates have filed suit against the state on grounds that the new oil and gas corporate income tax law is unconstitutional and discriminatory.

The suit, filed March 22 in Anchorage Superior Court, asks that the court prevent enforcement of the tax law passed by the 1978 legislature and order a refund of 1978 taxes paid under protest. The suit was filed by Arco Pipe Line Company, Atlantic Richfield Company, BP Alaska Inc., Sohio Natural Resources Company, Sohio Pipe Line Company--all the major North Slope producers except Exxon.

The oil industry met the Department of Revenue's March 15 deadline for payment of 1978 taxes under the new law--collectively paying $162.5 million this year.

The companies charged in the suit that the tax was tailored essentially to cover only companies owning production interests at Prudhoe Bay and is therefore discriminatory. The companies also charged that the tax violates constitutional protection against double taxation. The tax violates the equal protection and due process clauses of the Constitution because the tax bears no "fair relation" to services provided by the state, the companies claimed.

State Attorney General Avrum Gross said state attorneys researched potential constitutional challenges to the tax before the governor signed it into law last year.

"A lot of the questions are close, but it was our belief then that the court would uphold the constitutionality of it, and we believe so now," Gross said.

Petroleum Revenue Director Tom Williams said the suit may be in court one to three years before a final decision is reached.

TAPS TARIFF SETTLEMENT PROPOSED

Federal Energy Regulatory Commission Administrative Law Judge Maxwell Kane has proposed a partial settlement in the Trans-Alaska Pipeline tariff case that would substantially lower the state's cost of moving oil through the pipeline.

If the parties to the tariff case, which has been pending since the summer of 1977, agree to the settlement, the average tariff would be reduced to about $4.78 per barrel at a throughput of 1.35 million barrels a day, down from the current average of $6.21. State attorneys say oil company representatives have expressed little interest in discussing the proposed settlement.

The Legislative Research Division estimated that fiscal 1980 state revenues would be about $123 million higher if the settlement is adopted.

If the parties to the case refuse to accept the settlement, the Administrative Law Judge would make a ruling that could be appealed to the full FERC. FERC's decision could then be appealed to the federal courts.

The proposed settlement affects only "Phase I" general issues of methodology. The main issue to be resolved in "Phase II" involves the costs of constructing the pipeline.

STATE OIL TAX POLICIES DRAW NATIONAL CRITICISM

Two prestigious business publications claimed recently that unreasonable state oil taxes have impeded exploration and development of oil and gas reserves and prevented the nation from achieving energy independence.

"The clearest reason why oil companies are pulling back on further Alaskan development is the state's grab-the-money-and-run tax policies," Business Week said in an editorial February 26. "Alaskan officials...should stop treating the oil companies as the answer to all state financial needs, present and future. Sticking it to them now may look politically appealing, but in the long run it could mean less income for Alaska and less vitally needed oil for the rest of the country."

Business Week's editorial was accompanied by a lengthy cover story, "The Great Alaskan Oil Freeze," which detailed the factors--high transportation and operating costs, environmental problems, state taxes, and lack of exploration opportunities--causing the industry to leave Alaska.

Several weeks later, the Oil and Gas Journal claimed that "Alaska is no longer the plundered state--through runaway taxation it has become the plunderer."

"Alaska has erected as severe a barrier to development as the U.S. Government and the environmentalists," the March 12 Oil and Gas Journal editorial said. "It must not try to emulate OPEC's sharing of resource profits. There is a limit to entrepreneurial patience."

Although oil industry spokesmen have been making the same points for a long time, the articles angered some legislators.

Republican Senator Bill Sumner of Anchorage, who opposed the corporate income tax increase on the oil industry last year, said he was concerned that "continued exploitation of one-sided facts or one-sided conclusions" may discourage some companies from future involvement in Alaska. "If I keep hearing this song sung to the extent that it is counterproductive to Alaska, the industry would have a problem with me...I'm wondering who's promoting (these articles) and I'm going to try to find out...

"I'm prepared to review the oil taxation as it relates to the oil industry in Alaska. But what I'm not willing to do is to see this thing continue, the flames of this issue continue to be fanned to the point that it creates an adverse climate which serves to the detriment of the Alaska people," Sumner said at a March 16 meeting of the Senate Resources Committee.

Oil and gas consultant Milton Lipton agreed. "I felt very distressed about the (Oil and Gas Journal) editorial, not because I think Alaskan taxation in the petroleum field may not warrant legitimate and sensible criticism, but because the conclusions that were drawn from it were so extreme and I believe so wide of the mark and so inappropriate that it rather bothers me that the Oil and Gas Journal would do a piece such as that....I don't believe that the tax regime of Alaska is driving the oil industry away from exploration in Alaska," Lipton said.

Leasing

LEGISLATORS QUESTION TIMING, PREPARATIONS FOR BEAUFORT SEA SALE

Some legislators have raised questions about the Hammond administration's preparations for the December Beaufort Sea oil and gas lease sale, the state's first major lease sale since Kachemak Bay.

At an all-day hearing March 31, the House Resources and Finance committees heard about a dozen witnesses outline environmental, legal, economic and administrative problems that should be resolved if the sale is to proceed on schedule.

Spokesmen for Exxon and Chevron urged that the sale be held in December and that a cash bonus bidding method be used. The committees plan to hold another hearing in mid-April to take additional testimony from the oil industry on its ability to overcome environmental problems associated with drilling in Arctic waters.

Leadoff witnesses from the Legislative Affairs Agency research staff said that, in their view, the Division of Minerals and Energy Management has seriously underestimated the amount of work necessary to implement the new leasing law adopted by the legislature last year and is seriously understaffed for the job at hand.

Research Director Gregg Erickson pointed to recent management changes in the department as a reason for some of the problems in implementing the law. Preleasing regulations under consideration last year were dropped, Erickson said, "because of a perception on the part of the new division director, Mr. (Tom) Cook, that their adoption would even further complicate his already difficult tasks in getting state land under oil and gas lease."

Agency researchers also outlined problems that have developed in attempting to reconcile a large number of conflicting state and federal leasing laws and regulations. Issues not yet resolved include bidding methods, royalty requirements, length of leases, environmental stipulations and mitigating measures, unitization and other post-sale administrative activities, and an interim legal agreement to govern the disposition of bonuses and royalties from disputed acreage.

Spokesmen from the North Slope Borough, the area that will be most directly affected by offshore exploration in the Beaufort, said the sale is premature and should be delayed for environmental reasons. Borough Mayor Eben Hopson, who opposes any leasing beyond the Barrier Islands, said there is widespread opposition to the sale throughout the Borough and "my cooperative attitude is being maintained at increasing political cost."

Alaska Legal Services attorney Don Clocksin, representing the villages of Kaktovik and Nuiqsut and the City of Barrow, said his clients oppose leasing at this time inside as well as outside the Barrier Islands. "The basic position we take is that we do not know enough about the offshore area of the North Slope to proceed with a lease sale in that area at all at this time. We believe it is possible in the reasonably near future to have enough information, and assuming that information is positive...our clients take the position that as long as they can be assured that the activity can be done safely, their position will change and they will not oppose the lease sale," he said.

Clocksin said it is important to resolve environmental problems before leases are issued, because "industry takes the position that once they have leases, they have essentially an unalterable right to proceed with exploration and production. At the point the leases are issued, at least according to the industry point of view, we have lost much of our ability to restrict or prohibit certain types of dangerous activity."

The Department of Natural Resources did only a brief and "hopelessly inadequate" social analysis before deciding to hold the Beaufort sale, he said.

Clocksin and others questioned whether the technology currently exists for the oil industry to operate safely in the ice and permafrost conditions of the Beaufort Sea, particularly in the shear and pack ice zones in the area beyond the Barrier Islands.

Dr. William Sackinger, an associate professor at the University of Alaska's Geophysical Institute, said exploration could proceed in water depths of six to 35 feet, where there is some ice movement, but "I really think that we need a much longer data base to make a proper design for a production operation in that kind of water depth." The sale area encompasses water depths of up to 60 feet.

Some witnesses said industrial activity in the Beaufort Sea may harm the area's fish, wildlife and subsistence resources, particularly the endangered bowhead whale.

Chuck Evans of the Arctic Environmental Information and Data Center said it is going to take "at least two or three years to say definitely that bowheads do not occupy those waters (proposed for leasing) at any time." It is extremely difficult to predict the effect that industrial disturbance will have on wildlife, Evans said.

Much of the testimony at the hearing centered on administrative problems with the sale, in particular whether the Department of Natural Resources had conducted an adequate economic analysis to determine which bidding methods would best maximize the value of the resource. Legislators also wanted to know whether the administration was pursuing the best legal strategy in attempting to resolve an ownership dispute with the federal government over about 19 percent of the lands in the sale area.

Legislators questioned economist-consultant Arlon Tussing on how the unresolved West Coast oil surplus will affect bidding by the companies. "...If we have a cash bonus sale, those bonuses are going to reflect a great deal of uncertainty. The companies are almost certainly going to bid on the basis of what they anticipate the price will be of the marginal barrel on the Gulf and East coasts. They're going to assume that they're not going to be able to export and there will be no pipelines. These will be on top of the discounts with respect to engineering uncertainty, taxes, inflation and so on," Tussing said.

Natural Resources Commissioner Robert LeResche said that although many things remain to be worked out, the department will complete a responsible analysis of the problems in a timely manner.

"I can tell you that if we decide the best way to (lease) the Beaufort is net profits (bidding), we'll be perfectly capable of doing it within the time frame allotted. And despite Tom Cook's earlier unfortunate remark that it would be an administrative nightmare, there are ways we can make it administrable without a lot of problems," LeResche said.

The state will be assisted by 30 or 40 federal USGS employees who already have gathered a great deal of seismic and geologic data, he said. "I personally consider that perfectly adequate preparation and data-gathering for a sale of this magnitude."

DMEM CONSIDERS CASH BONUS BIDDING SYSTEMS FOR BEAUFORT SALE

Although no final decisions have yet been made, state officials involved in planning the Beaufort Sea lease sale currently favor a system of cash bonus bidding. This system might be coupled, however, with a lease that requires the producer to share his profits on a fifty-fifty basis with the state.

The main points of this system now under discussion by personnel of the Division of Minerals and Energy Management (DMEM) in the Department of Natural Resources are:

- The state's nominal share of the net profits would be fixed at between 40 and 50 percent.
- The lease would be awarded to the bidder offering the highest cash bonus.
- Only 20 percent of the cash bonus would be required to be paid immediately, with the balance to be paid over as much as 10 years.
- Net profits payments would not be made to the state until the producer had recovered all investments in developing the tract, plus accrued interest; the bonus payment would not be counted as part of the development investment.
- The lease agreement would also provide for the payment of a minimum (12½%) royalty to the state.

Because of the allowance for capital recovery, little or no net profits would be paid to the state during the early years of production. However, the state would receive annual installments on the deferred bonus, and after production began, would also collect severance tax, the 12½% royalty, and probably income tax payments as well.

An important question not yet resolved, and one that would have significant impact on the amount of time that would elapse before the state started to collect its net profit share, relates to the rate at which the producer would be allowed to accrue interest expenses on his development costs. A relatively high rate of interest (18-20% per annum has been mentioned) would mean that a much longer period of time would elapse before the state would start to collect its net profit share.

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Although the net profits leasing system described above is the one currently being given the most serious consideration by DMEM, and the one that has been embodied in informal draft regulations, three other systems also have been discussed. They are:

1. The so-called "British system," which the federal government currently favors as its system of choice if a net profits arrangement is adopted on any of the federal or disputed tracts leased in the Beaufort Sea. The biggest difference between this system and the one currently preferred by the state is that no interest on development expenditures would be allowed. Instead, the producer would be permitted to recover up to twice the amount invested in development of the tract before he would be required to start paying the nominal net profits share to the government.

2. The net income tax system, under which the existing state corporate oil and gas income tax calculations would be used to determine the net profits base. Under this system payments would be much more evenly distributed over the producing life of the lease. In addition, it would eliminate the need for both the producers and the state to keep separate sets of books for net profits lease accounting.

3. The so-called "annuity system," under which the development investment would be recovered with interest over some arbitrarily selected period of time roughly corresponding with the life of the field.

Even if the formal issuance of draft regulations governing net profits leasing is deferred until mid-July, that may not be sufficient time to thoroughly evaluate the relative merits of the four possible net profits leasing schemes, and the many possible variations among and within them. The actual computer analysis of the revenue impacts of the various systems has begun in earnest, but the system currently preferred by the state is the only one on which any detailed studies have yet been completed. The choice of the net profits leasing systems selected for computer analysis will have a crucial effect on the relative attractiveness of net profits leasing to the traditional cash bonus bid system.

INDUSTRY URGES RAPID OCS DEVELOPMENT; RURAL ALASKANS WANT DELAY

Coastal communities all around Alaska want the federal government to delay oil lease sales in Outer Continental Shelf waters, local government representatives, Native leaders and citizens told state and federal officials March 27.

The subsistence lifestyle of Bush Alaskans must be protected; oil companies should be encouraged or forced to hire local residents; more money for local planning and impact assistance needs to be appropriated; and OCS leasing should proceed slowly in a manner that will not disrupt traditional lifestyles, the officials were told.

"Our area is at a very early stage of planning," said Diane Carpenter, a member of the Bethel City Council. "We realize oil development can't be avoided; our concern is the timing.... Maintaining subsistence resources is the primary concern.... This area needs money to plan for the impacts, and we may need more time."

Governor Jay Hammond scheduled the televised "town meeting of the air" to get comments from Alaskans on the Interior Department's draft proposed five-year OCS leasing schedule.

Thirty-one nationwide OCS sales are scheduled by Interior between now and 1985; 10 of them are in Alaska. Two of the Alaska sales--in the Chukchi Sea and St. George Basin--were included in the proposed plan on a fallback basis in case other planned sales eventually are deleted. (See chart, page 20, for list of proposed federal sales.)

Three areas listed in the earlier OCS plan--Hope Basin, the Southern Aleutian Shelf and Bristol Basin--were deleted from the latest draft plan.

Comments on the draft program are due April 20; Interior will submit a revised "proposed program" to Congress by June 18. After further comment from affected states and the public, a "final" version will be sent to President Carter and Congress late next fall.

While some rural Alaskans said the schedule was too rapid, industry spokesmen complained that it was not rapid enough.

"It is probably safe to say that under the proposed schedule, some of our nation's best prospects could not be brought into production before 1995," said Bill Hopkins, executive director of the Alaska Oil and Gas Association. "It is clear that the schedule does not emphasize the goal of bringing the more promising Alaska areas into play as a hedge against Iranian-scale energy disruptions a few years down the road."

Interior officials characterized the program as an attempt to balance the nation's thirst for oil and the fragile marine environment.

Industry interest in the Alaska areas proposed for leasing, and the U.S. Geological Survey's assessment of their hydrocarbon potential, are summarized in the chart below:

Oil and Gas Potential of Proposed OCS Leasing Areas

	U.S. Geological Survey			Industry Ranking[3]	
	95%[1]	5%[1]	S/Mean[2]	Resource Potential	Interest in Exploration
Beaufort Sea	0 0	7.6 19.3	3.28 BBO 8.2 TCFG	2nd of 22 areas	3rd of 22 areas
Gulf of Alaska	0 0	4.4 13.0	1.3 BBO 3.39 TCFG	17th of 22 areas	16th of 22 areas
Kodiak	0 0	1.1 3.5	0.23 BBO 0.69 TCFG	19th of 22 areas	21st of 22 areas
Cook Inlet	0.5 1.0	2.3 4.5	1.19 BBO 2.39 TCFG	16th of 22 areas	13th of 22 areas
Norton Basin	0 0	2.1 2.8	0.54 BBO 0.86 TCFG	9th of 22 areas	10th of 22 areas
Chukchi Sea	0 0	14.5 38.8	6.4 BBO 19.8 TCFG	10th of 22 areas	17th of 22 areas
Navarin Basin	0 0	1.9 4.8	0.36 BBO 0.93 TCFG	11th of 22 areas	12th of 22 areas
St. George Basin	0 0	5.1 13.1	1.32 BBO 3.37 TCFG	5th of 22 areas	9th of 22 areas

[1] These USGS probability rankings mean that, in the case of the Beaufort Sea, there is at least a 5 percent chance that no oil or gas will be discovered, and there is a 5 percent chance to discover more than 7.6 billion barrels of oil and more than 19.3 trillion cubic feet of gas.

[2] The expectation is that 3.28 billion barrels of oil and 8.2 trillion cubic feet of gas will be discovered in the Beaufort Sea.

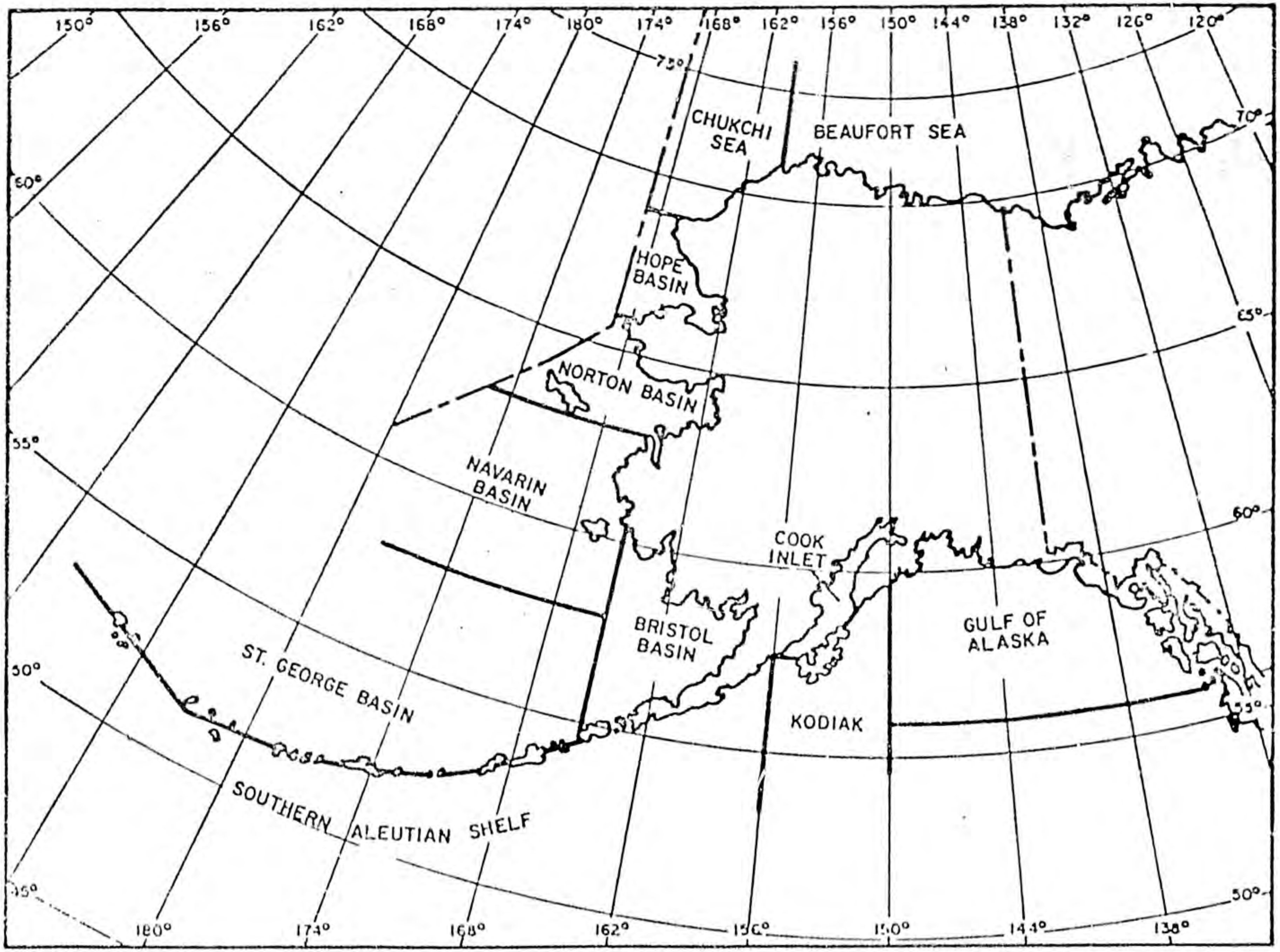
[3] Expressed in relation to the 22 original areas throughout the U.S. (including the Gulf of Mexico, Atlantic and Pacific coasts) proposed by Interior for leasing in 1980-85.

State and Proposed Federal Oil and Gas Leasing Schedules

Year		State	Federal
1979	July	Copper River Basin	
	Dec.	Beaufort Sea*	Beaufort Sea*
1980	Early	Arctic Slope relinquished tracts	
	Mid	Cook Inlet south of Kenai River	Gulf of Alaska (October)
	Late	Upper Cook Inlet (onshore, offshore, Susitna Valley)	Kodiak (December)
1981	Early	Lower Cook Inlet* (offshore and onshore)	
	Mid	Prudhoe Bay Uplands	Cook Inlet (September)
	Late	Norton Basin* (offshore and onshore)	
1982	Early	Beaufort Sea	
	Mid	Middle Tanana Basin Copper River Basin	
	Late	Southwest Bristol Bay uplands	Norton Basin (November)
1983	Early	Upper Cook Inlet (onshore and offshore, Susitna Valley)	Beaufort Sea (February)
	Mid	Chukchi Sea* (onshore and offshore)	
	Mid	Norton Basin	
	Late	Minchumina Basin	
1984			Cook Inlet (April) Chukchi Sea (December)**
1985			Navarin Basin (January) St. George Basin (February)**

* The state plans to coordinate these sales with the federal government.

** Contingency sales.


CHUKCHI SEA
BEAUFORT SEA
HOPE BASIN
NORTON BASIN
NAVARIN BASIN
COOK INLET
BRISTOL BASIN
GULF OF ALASKA
ST. GEORGE BASIN
KODIAK
SOUTHERN ALEUTIAN SHELF
150°
156°
162°
168°
174°
180°
174°
168°
162°
156°
150°
144°
138°
132°
126°
120°
75°
70°
65°
60°
55°
50°
180°
174°
168°
162°
156°
150°
144°
138°

9

GAS PIPELINE DIFFICULTIES CONTINUE

The long list of regulatory roadblocks impeding construction of the Alaska Highway Gas Pipeline is slowly getting shorter, but the lack of a credible financing plan continues to stymie real progress.

Northwest Alaskan Pipeline Company, leader of the six-company consortium designated to build the Alaska segment of the pipeline, still publicly maintains its intent to secure private financing, as required by federal law, although it acknowledges this will be a difficult task.

Energy Secretary James Schlesinger told Congress several months ago that federal financing assistance might be necessary. President Carter, however, has not asked Congress to approve federal backstopping, and he is not expected to do so anytime in the near future.

President Carter reaffirmed his "strong commitment to the pipeline" after a meeting March 3 with Canadian Prime Minister Pierre Elliott Trudeau, but the President failed to mention the Alaska gas pipeline in his national energy message April 5. The President did finally submit to Congress his long-awaited proposal to slightly reorganize the federal bureaucracy and create the Office of Federal Inspector. The Federal Inspector, who has not yet been nominated by Carter, will have sole authority to supervise enforcement of permit regulations during construction of the Alaska pipeline.

Carter's proposal differs from the inspector envisioned in the 1977 President's Decision selecting the Alaska Highway route for the pipeline. The main difference is to strengthen the authority of the inspector by limiting appeals of his decisions.

While the federal government moved closer to getting its chief enforcement officer aboard, State Pipeline Coordinator "Mo" Mathews and more than half his staff resigned rather than move to Fairbanks.

Governor Jay Hammond promised while campaigning last fall that he would move the state inspector's office to Fairbanks to help boost the city's depressed economy. But Mathews said he didn't think the office should move until shortly before construction begins, probably in the early spring of 1982. A spokesman for the Department of Natural Resources said a replacement for Mathews probably will be named by May 1 when his resignation becomes effective.

In apparent response to pressure from the White House and Schlesinger, the Federal Energy Regulatory Commission (FERC) announced in February it would expedite progress on the unresolved tariff and Incentive Rate of

Return (IROR) issues by consolidating them in a single rulemaking proceeding. The State of Alaska objected to this procedure, claiming an evidentiary hearing is needed and an informal rulemaking is inadequate to address state concerns.

"There's been a lot of movement in the last few months. Things at FERC are heating up, and I think there's been a significant change in tone," said Assistant Attorney General Bob Maynard, who handles oil and gas matters for the state. "But it's still unclear whether all this movement means anything."

The announcement that Exxon USA and Pacific Gas & Electric Co. had completed negotiations on an agreement for the sale and purchase of about 225 million cubic feet of gas a day for 20 years was a boost for the project.

Northwest cited FERC's attempt to speed up resolution of the financial and regulatory issues as another encouraging sign of "renewed momentum." However, the regulatory logjam is far from broken.

In January, Northwest submitted a "checklist" enumerating more than 50 of the most critical items requiring immediate government action if the project is to be finished in late 1984. Yet there has been a conspicuous lack of action on most of the items, Northwest said.

"The commitment to expeditious implementation of the President's Decision with regard to the Alaskan gas project by senior administration officials is unquestioned," John G. McMillian, Northwest's chief executive officer, said in a March 20 update to Schlesinger on the project's status. "I respectfully suggest, however, that there is an urgent need to imbue such a determination at the sub-Cabinet and middle management levels."

The most pressing issues that must be resolved before June, Northwest said, include the Limited Reorganization Plan (which establishes the Federal Inspector), the commitment by the Secretary of the Interior to grant a right-of-way on federal lands, approval by FERC of system design specifications, resolution by FERC of the tariff and IROR, and final decisions on the environmental, construction and technical stipulations affecting pipeline route and design.

However, government memoranda on one pending matter--alignment of the gas pipeline in relation to TAPS--indicate that Northwest itself is responsible for a lot of the foot dragging. (See next item.)

In addition to problems on the regulatory front, no one as yet has been willing to put up the $12 billion to $14 billion needed to build the pipeline.

Consultants Arlon Tussing and Connie Barlow told the legislature in a final report, which will be released in mid-April, that the pipeline cannot be financed and built unless the United States government guarantees at least part of the project debt.

This judgment, the consultants said, "is held almost unanimously by the natural gas transmission industry, Alaska gas producers, investment bankers, lending institutions, state and federal regulators, and concerned members of Congress. The only significant dissent we encountered in more than six months of investigation came from a few top officials of the United States Department of Energy and from Northwest...the project's principal sponsor.

"Northwest thereby bears a double handicap in moving ahead on any front. Not only does it have an unworkable financial plan, but because the gas producers, potential shippers (including Northwest's own partners), state officials and important parts of the federal bureaucracy all believe the plan is unworkable, they do not sense any urgency in cooperating with Northwest or with one another in resolving even the nonfinancial issues. Because the project's financing is not credible, in other words, the whole project as presently organized is not credible," Tussing and Barlow said.

"Thus, any entreaties to the other parties by Northwest's chairman, 'jawboning' by the Secretary of Energy, or declarations of faith by the President of the United States come to nothing--they only seem to confirm what many of the parties suspected all along, that Messrs. McMillian, Schlesinger and Carter don't know what they are talking about," the consultants said.

The Alaska legislature and state administration appear firmly convinced that too many unknowns remain for the state to pledge $1.5 billion to the project at present.

Despite an ultimatum from McMillian to Governor Hammond in February, which stated that private financing would be impossible unless the state unconditionally committed $500 million in preferred equity and approved issuance of $1 billion in tax-exempt revenue bonds during the current legislative session, legislation authorizing the state commitment was never introduced for consideration in either body of the legislature.

The possibility remained that the legislature might authorize a fact-finding evaluation team, or a negotiating team, of legislators or administration officials to pursue the possibility of a direct state commitment over the interim, an approach supported by some members of the Senate and the administration.

The state House passed a non-committal resolution of support for the project in early March; House leaders subsequently informed the governor that "no further action" should be expected from the House this session on proposed negotiations with Northwest.

Nevertheless, Northwest in March kicked off a public relations and advertising campaign calculated to win support for its proposed special election on a $500 million general obligation bond issue for the project. Legislative attorneys said it probably was illegal to issue g.o. bonds for the pipeline, and it appeared unlikely the legislature would approve such an election.

Northwest released a statewide poll by the Rowan Group of Anchorage showing that from 50 to 56 percent of the 800 people surveyed approved of state financial participation in the gas pipeline.

However, a survey of Southcentral residents by Representative Randy Phillips found that 81 percent of 487 people responding to his questionnaire opposed the investment of surplus state funds in the gas pipeline.

Northwest hired a team of lobbyists to seek support in the legislature, including the governor's former executive assistant, Kent Dawson, and former state Representative Bob Bradley of Anchorage. A citizens' group headed by Anchorage businessman Les Gunderson and state Republican Party Chairman Yvonne Alford set out to get 100,000 signatures on petitions urging the legislature to negotiate with Northwest.

The issue of federal expectations for financial participation by the state government was addressed in a study by Joseph Chomski and Richard Haggart of the law firm Birch, Horton, Bittner and Monroe. The study concluded that there is not a general expectation in Washington that the state will financially participate in the project.

However, Chomski and Haggart said, the federal government possesses a large arsenal of weapons, ranging from the ability to control state oil and gas production decisions to the ability to prohibit oil exports and swaps, that could be used as leverage to force state participation.

The legislature received a wide range of advice on whether, when and how to pledge state money to the project. Alaska Senator Ted Stevens said state guarantees secured exclusively by revenues derived from the sale of North Slope gas would be a reasonable way to proceed; he said a state commitment would help assure private financing.

The Anchorage Times called McMillian's urgent request for assistance "an unattractive deal" for the state. "If the traditional financial centers of the nation find (investment in the pipeline) a bum deal, why isn't it a bum deal for the state, too?" the Times asked in a February 12 editorial.

Legislative consultant Milton Lipton said the nation's desire to tap Alaska's natural gas resources makes it very likely the pipeline eventually will be built, although "this doesn't necessarily mean that...the partners of the present Northwest consortium will be the ones that will build the pipeline." Lipton said he found it troublesome that the state had been asked to conclude the terms of its participation before seeing how it would rank among other creditors and among other equity participants. He suggested that the state wait to see a complete financial package before making a commitment.

Some of the regulatory matters affecting progress of the pipeline are discussed in more detail below:

Conditioning costs

In early February, FERC issued a proposed rulemaking that would require North Slope producers to bear all costs of processing and conditioning Prudhoe Bay gas. FERC wants the producers to pay for these costs, estimated at 30 to 60 cents per mcf, out of the money they'll receive from selling at the ceiling price established in the new Natural Gas Policy Act. No adjustments for conditioning above the ceiling price would be allowed under FERC's proposal, except in "special hardship" cases.

FERC said this allocation of costs would enhance financeability of the pipeline, improve marketability of the gas, avoid the complications of incremental pricing, and generally be in the public interest.

In formal comments filed in March, Exxon, ARCO and Sohio strongly objected to FERC's proposal, contending, among other things, that it is contrary to Congressional intent, discriminatory and a disincentive both to production of Prudhoe Bay gas and to further exploration and development in Alaska and other frontier areas. The producers argued that conditioning Prudhoe Bay gas is a function related to transportation, not production. They urged FERC to wait for the execution and submission of gas purchase contracts before taking up the issue of gas conditioning.

The State of Alaska, making arguments similar to those advanced by the producers, said the FERC conditioning proposal was premature and was causing unnecessary confrontation and delay. The state said there is nothing in the record to support the assertion that an adjustment for conditioning costs would affect marketability of the gas. Whether the state will have to pay conditioning costs on its royalty share may be determined by the outcome of litigation now pending in state court.

The FERC staff, the New York Public Service Commission and the California Public Utilities Commission all endorsed the commission's proposed policy.

Neither Northwest Alaskan nor the Alaskan Northwest partnership filed comments on FERC's conditioning proposal. One member of the Alaska partnership, Pacific Interstate Transmission Company (which also is involved in construction of the Western Leg), said its ongoing gas sale negotiations with ARCO were suspended after FERC's proposed rule was issued. Since FERC's present position may continue to impede delivery of Prudhoe Bay gas to the Lower 48, Pacific Interstate urged FERC to reexamine its position and "permit the gas producers to collect such allowances for gathering and conditioning costs as are appropriate and justified to reflect the unique and special circumstances that exist for Prudhoe Bay gas."

Subsequently in a round of "reply comments," Exxon said its negotiated gas sales contract with PG&E provided for sale "at or near the inlet to the conditioning facility." This means PG&E could bear all, or almost all, of the conditioning costs, exactly the opposite of the FERC proposal. Observers predicted the matter ultimately will be settled in court, unless FERC reverses its current position.

On March 5, the State of Alaska filed a "freedom of information" request with FERC seeking release of all studies, documents and communications related to the conditioning issue. State attorney Robert Loeffler said he has been informed that FERC will refuse to release about 50 conditioning-related documents, and he said he is considering suing FERC over the issue. "It just doesn't seem right to me that FERC should adopt this important rule without making their documentation and records available for comment and response by the affected parties," Loeffler said.

Observers said FERC might take final action on its proposed conditioning rule by mid-May.

Tariff and IROR

FERC announced February 22 that it intended to consolidate the remaining unresolved IROR and tariff issues into a single rulemaking proceeding. A 90-page "omnibus proposed rulemaking" was issued April 6; comments on the proposal are due May 4.

The Alaskan Northwest partnership filed its proposed tariff structure with FERC March 12. The tariff document sets out the framework for rates and charges for gas transportation through the pipeline.

Alaska told the commission in formal comments and at discussion conferences that some of its concerns might not be adequately addressed in an informal rulemaking, and said it may request formal evidentiary proceedings on some issues. Alaska said it was concerned with, among other things, how tariff charges will be allocated between methane and heavier liquids, how rates will be established for new shippers in the future, how much CO_2 will be permitted in the pipeline, and how the zone tariff will be structured.

Alaskan Northwest had urged FERC to expedite consideration of the complex financial structure. The partnership said it is of "critical importance" that FERC settle the upper and lower limits for the rate of return allowed on the Alaska segment, and other related issues, by May 15 if the 1984 completion date is to be met.

Pressure and design

On March 2, the Alaskan Northwest partnership asked FERC to approve design specifications for the pipeline. These specifications designate a 48-inch pipeline with a maximum working pressure of 1260 psig, and would provide an initial capacity of 2.0 to 2.4 billion cubic feet a day (expandable up to 3.2 Bcf a day with additional compressor stations).

Alaskan Northwest said it had investigated various alternative pressures, but had concluded that its proposal was the best economic selection for delivering volumes up to 3.4 Bcf a day. Alaskan Northwest said it had considered and rejected a higher pressure system suggested by the State of Alaska that would enable movement of a greater volume of liquids for extraction and potential use in developing an in-state petrochemical industry.

Alaskan Northwest asserted that its proposed 1260 system would not impede the petrochemical development plans of the state, since this system could transport all of the ethane and propane in the Prudhoe Bay gas stream. While a higher pressure system could carry greater volumes of heavier hydrocarbons (primarily butane), these liquids would not be useful in a petrochemical plant, nor could they be transported in the Yukon section of the line.

In addition, Alaskan Northwest said, if the conditioning plant were moved to Fairbanks (as proposed by Earth Resources Co. of Alaska) and if most of the ethane and all heavier hydrocarbons were removed at Fairbanks, total deliverable energy through the project would be reduced by 20 to 25 percent. "This substantial reduction would render the project infeasible," the partnership said.

In reply comments, the State of Alaska said no evidence had been presented in the record to substantiate the partnership's claims that all ethane and propane can be carried at 1260 psig. If the partnership's assumptions are accurate, the state said, it does not object to approval of a 1260 system. However, more CO_2 should be allowed in the gas stream, and Fairbanks should not be foreclosed as a location for the conditioning plant, the state said. The project's Environmental Impact Statement will investigate Fairbanks as a location for the conditioning plant; if Fairbanks turns out to be a better place than the North Slope, the system would have to be redesigned from Prudhoe Bay to Fairbanks, the state said.

FERC is expected to approve the 48-inch, 1260-psig system in late April or early May.

Western and Eastern Legs

Canada's National Energy Board (NEB) said in a report released February 28 that the country has 2 trillion cubic feet of surplus gas that can be exported during the next eight years.

This conservative estimate of Canada's gas surplus falls far short of the 8 trillion cubic feet needed to satisfy all the export applications currently on file with the NEB. One of those applications by Pan-Alberta Gas Ltd. of Calgary is linked to prebuilding of the Alaska Highway gas pipeline southern sections.

Alaskan Northwest and U.S. energy officials said the NEB report was favorable to the Alaska Highway gas pipeline project because it clearly demonstrated the limits of Canadian supplies and would add urgency to U.S. efforts to tap North Slope gas.

Alaskan Northwest is counting on prebuilding of the Western and Eastern legs of the system for the early export of surplus Canadian gas, in order to facilitate financing of the entire system.

A Canadian newspaper, The Financial Post, said the NEB report jeopardized the prebuilding scheme. "The (NEB) determined Canada simply didn't have enough surplus gas to warrant exports of the magnitude needed by the Alaska Highway (project)," the newspaper reported March 17.

Canadian officials continued to emphasize their reluctance to approve exports for the Alaska Highway pipeline's southern sections until financing is arranged for the Alaska segment.

"Canada would need to be fully satisfied expeditious construction of the whole project would proceed as planned" before allowing exports for the prebuilt sections, Peter Towe, Canadian ambassador to the U.S., said in a March speech.

TAPS OWNERS QUESTION PROXIMITY OF GAS PIPELINE

Owners of the Trans-Alaska oil pipeline say it may not be possible to build the gas pipeline alongside TAPS, as Northwest Alaskan has planned.

In a February 15 letter to Interior Secretary Andrus, the TAPS owners cited a number of factors--possible damage from blasting and equipment during construction, slope stability and soil liquefaction, erosion control and surface drainage, alternation of the hydraulic regime in rivers and flood plains, effects upon the thermal regime, below ground pipeline soil support, work pad stability, ditching effects, and hindrance to TAPS monitoring and maintenance by Alyeska--that could prevent a close alignment between the two pipelines.

"The TAPS owners are not questioning the technical feasibility of constructing an Alaskan Natural Gas Transportation System. Rather, they are seriously questioning the compatibility of the gas line with TAPS.... It may be that many of the proximity issues can only be resolved on a mile-by-mile basis, i.e., at the time a notice-to-proceed is issued. It may be that the gas line cannot be constructed proximate to TAPS at any point. In any event, additional information must be submitted by Northwest before the issue of gas line proximity to TAPS can be considered," said Alyeska President Frank Turpin.

Northwest has been trying since December to secure "provisional approval" for its proposed alignment of the Alaska gas pipeline in relation to the TAPS oil pipeline; this approval is needed for Northwest to give FERC a reliable estimate on the cost of the project.

Government agencies responsible for approving proposed alignment for the gas pipeline agree with Alyeska that the information submitted by Northwest is inadequate. A joint report by BLM's Alaska Pipeline Office, the State Pipeline Coordinator's Office, the Corps of Engineers, the U.S. Fish and Wildlife Service, the Environmental Protection Agency and the U.S. Geological Survey stated: "Proposed alignment sheets and narrative description of the proposed route submitted by Northwest Alaskan Pipeline Company are inadequate to review for provisional alignment approval. Criteria for route selection was not a part of the submittal, therefore making a thorough review impossible."

LEGISLATURE CHANGES APPROVAL PROCEDURE FOR GAS PIPELINE FINANCING AUTHORITY

The Alaska House and Senate have adopted legislation that will make it more difficult for the Gas Pipeline Financing Authority to gain legislative approval to issue $1 billion in tax-exempt revenue bonds for the Alaska Highway gas pipeline.

Under the 1978 law that established the financing authority, a financial plan submitted by the authority would have been approved in 30 days unless disapproved by one house or conditionally approved by both houses.

But under an amendment sponsored by Representative Russ Meekins of Anchorage and adopted in the House April 9 by a vote of 35 to 3, the authority's financing plan would be disapproved unless approved or conditionally approved by both houses within 60 days after presentation to the legislature.

"I think we made a real mistake last year and I'm trying to remedy that mistake," Meekins said. "We reversed the normal process of this legislature.... This (amendment) puts the burden of proof on the people who want the billion dollars, and not on those who are opposed to it."

The House also adopted an amendment to existing law that moved the date for submitting a financial plan back to the first day of the next legislative session.

The Gas Pipeline Financing Authority, in compliance with current state law, submitted a "financial and Alaska impact plan" to the legislature on March 14. But because of delays and other problems, the authority said a complete plan is impossible at this time and recommended that the plan be "conditionally approved."

The House adopted a resolution conditionally approving the plan; the resolution said no bonds can be issued until the plan is amended and again approved by the legislature.

No matter what the state legislature does, the authority cannot issue the tax-exempt revenue bonds unless and until Congress amends Section 103 of the Internal Revenue Code, an action many observers consider unlikely.

"A year ago when we wrote the enabling legislation, we thought that by now we would have some concise, clear answers to the question of financing the gas line, especially so far as those questions relate to the bonding authority," said Representative Bill Miles of Anchorage. "Our position is that we don't have the answers...they haven't been forthcoming, the federal government has been slow in responding and we just can't make a decision at this time. It would be absolutely irresponsible for us to do so."

But Representative Brian Rogers of Fairbanks, arguing against HB 438 that makes changes in the financing authority's procedures, said the bill "puts the House on record as favoring delaying any financing of the project, regardless of merit, for at least a year.... This bill puts roadblocks in the financing authority, and I think will delay the time when people in my district, and a lot of other districts, will be going back to work."

On April 12, the Senate adopted the amended House version of HB 438 by a vote of 13 to 5; the Senate adopted the resolution conditionally approving the financing plan by a vote of 12-7. Without action by both houses conditionally approving the plan, or action by one house to disapprove, the plan would have taken effect April 14. Some legislators wanted to prevent the plan from taking effect in its current form in order to foreclose any possibility that bonds could be issued without further legislative action.

AGO 532649

WILDERNESS VS. OIL DEBATE ACCELERATES IN CONGRESS

The coastal plain of the Arctic National Wildlife Range (ANWR) may soon play host to seismic teams and drilling rigs as well as migrating snow geese and Porcupine caribou.

The ANWR, a nine million-acre area in the state's extreme northeast corner, was established by President Eisenhower in 1960. The range is part of a larger potential oil and gas basin encompassing most land north of the Brooks Range from the Canadian border to the Chukchi Sea.

Environmentalists and the Carter administration consider ANWR highly sensitive to industrial disruption, extroadinarily pristine, and "the last place in the world" that oil development should take place.

The oil industry, pro-development interests and the State of Alaska say the area should be explored and thoroughly assessed before it is permanently designated as wilderness, where all development is prohibited.

Although proposed wilderness status for ANWR is one of the most controversial provisions of the environmentalist-backed d-2 proposals, the oil industry has other problems with them as well. Industry spokesmen argue that even though most of the state land now considered to have a "high potential" for oil and gas accumulations is outside proposed withdrawals, exploration activities generally are at a very early stage and much of the land proposed for withdrawal has not been properly evaluated. Lack of access across the withdrawals will make it very difficult to build onshore support facilities, roads and pipelines necessary to develop remote deposits, they say.

The oil industry also claims that its activity at Prudhoe Bay has had very little negative impact on delicate ecological systems and wildlife.

An orderly assessment of Alaska's resource potential, including exploration of ANWR, is a necessary and prudent step in light of the national energy crunch, the urgent need to increase domestic production and the decline of nuclear power since the near-disaster at Three Mile Island, development forces have argued.

Although not addressed specifically in the state's d-2 "consensus points," lawyer-lobbyist John Katz said the state is supporting an orderly, environmentally sensitive approach to exploration on ANWR's coastal plain. Katz said the state has not taken the lead in advocating any particular plan but "basically has been supporting what (the oil companies) have been arguing for."

These arguments apparently are winning new support in the U.S. House of Representatives. The House Committee on Interior and Insular Affairs, chaired by Morris Udall of Arizona, on March 1 reported out a less restrictive bill than Udall's new version of H.R. 39. The Huckaby substitute, as it is called, would allow limited exploration of the coastal plain of ANWR.

The House Merchant Marine and Fisheries Committee on April 9 adopted a bill industry may like even better, the Breaux substitute. The measure was approved earlier by a Merchant Marine subcommittee on fish and wildlife, chaired by John Breaux, D-La. It mandates a seven-year resource assessment study of the range's coastal plain, which would include oil and gas exploration and biological wildlife studies.

Katz said the House is most likely to vote on d-2 sometime between April 30 and mid-May. Senate energy Chairman Henry Jackson, D-Wash., has said he won't begin markup in the Senate until the House has acted.

The major provisions of the pending bills as they affect ANWR are summarized below:

Udall bill (HR 39)--Sponsored by Udall and 139 other members of the House. The new HR 39 is considered by industry to be decidedly more antidevelopment than the version the House approved last session by a vote of 277 to 31. The new HR 39 would designate 84.5 million acres of wilderness, including the ANWR and some of the National Petroleum Reserve in Alaska. The bill would expand the size of ANWR by 9.9 million acres.

Durkin bill (S 222)--Sponsored in the Senate by John Durkin, D-N.H., and 17 other senators. This bill is nearly identical to the new version of HR 39.

Huckaby bill (HR 2199)--Sponsored by Representative Jerry Huckaby, D-La., and adopted by the House interior committee. This is essentially the same "compromise" bill nearly adopted last year but killed by Alaska Senator Mike Gravel at the last minute. Provisions in the bill affecting oil and gas development include:

- ANWR is not wilderness. A six-year study of ANWR's oil and gas potential would be conducted; no drilling could occur without congressional approval. ANWR would be expanded by 8.4 million acres.
- The Interior Secretary would have to make prompt decisions on whether to approve or reject lease applications in "refuge" withdrawals, which are open to oil and gas leasing under current law.
- The federal government would study the entire North Slope to ascertain oil and gas potential.

- The Interior Secretary would be directed to facilitate oil and gas leasing for non-North Slope, on-shore federal lands not included in conservation units.

Breaux amendments to HR 39--Sponsored by Breaux and adopted by the House Merchant Marine and Fisheries Committee. Provisions affecting ANWR include:

- The Interior Secretary is directed to conduct a two-year study of fish and wildlife of the coastal plain, and to assess the impacts of human activities.

- The Interior Secretary has two years to adopt regulations governing exploration activity on the coastal plain; the regulations must be accompanied by an environmental impact statement on exploratory activities.

- After regulations are adopted, "any person" may submit one or more plans for exploratory activity to the secretary for approval. "Exploratory activity" means surface geological exploration or seismic exploration. The secretary must approve the plan if it is consistent with the regulations.

- Five years after the bill is enacted, any person may apply for a permit authorizing the drilling of off-structure stratographic test wells in the coastal plain. The secretary has to hold at least one public hearing in Alaska before deciding whether to issue a permit.

- Not later than seven years after the bill is enacted, the secretary would recommend to Congress whether further exploration, and development and production, should be permitted, considering the area's petroleum potential and possible adverse effects on wildlife.

Jackson bill (S 9)--Sponsored by Jackson, and essentially the same bill the Senate Energy Committee reported out last fall. This bill would direct the Interior Department to conduct an eight-year study of ANWR, including some oil and gas exploration, to determine if the area should be permanently set aside as wilderness. Congress would have 60 days to approve or disapprove a recommendation from the Interior Secretary on whether the government should conduct exploratory drilling in ANWR. At the end of the eight-year study, the president would recommend to Congress whether the area should become wilderness.

The bill would expand the size of ANWR by 5.6 million acres.

PACIFIC ALASKA LNG PROJECT GETS FAVORABLE RULING FROM FERC

The Federal Energy Regulatory Commission has refused to consolidate the application of a new proposed California LNG terminal with pending proceedings of the Pacific Alaska LNG project.

Supporters of the Pacific Alaska LNG project had strongly opposed consolidation, saying that the resulting delays might be enough to kill their project.

FERC decided April 5 to deny the request of the Southern California LNG Terminal Company for consolidation of its application for a terminal at Deer Canyon, California, with that of Western LNG Terminal Associates, which has proposed a terminal at Point Conception, California.

Western's LNG terminal would receive Cook Inlet gas liquefied at Nikiski and shipped to southern California, as well as liquefied natural gas from Indonesia.

The Western LNG terminal, the Pacific Alaska LNG project, and the Pacific Indonesia LNG project are sponsored jointly by subsidiaries of Pacific Lighting Corp. and Pacific Gas & Electric Co.

The State of Alaska, the State of California and the California Public Utilities Commission supported the Pacific Alaska project sponsors in fighting the proposed consolidation. California said in comments to FERC that the majority owner of Southern California LNG (SCLNG) Terminal Company is also an owner of the Deer Canyon property proposed as a terminal site. When it became clear that Western LNG would not purchase Deer Canyon as the site for its terminal, SCLNG was formed as an allegedly competitive LNG application, California said.

California said that Deer Canyon already has been considered and rejected as a possible LNG terminal site by agencies and staffs of the State of California and the federal government.

The Pacific Alaska LNG project has been pending before federal regulators since 1974. (See Energy Background Report #3, December 8, 1978, for background on the Pacific Alaska project.)

GAO REPORT CRITICIZES GOVERNMENT EXPLORATION PROGRAM IN NPRA; CONGRESS DEBATES FURTHER FUNDING

A report by the U.S. General Accounting Office says the Interior Department's multi-million dollar North Slope exploration program has been needlessly rushed and hampered by a lack of clear objectives and definitive plans.

The federal government has spent more than $600 million drilling 19 exploratory wells (all dry holes) in the National Petroleum Reserve in Alaska (NPRA) since 1974.

"We believe the exploration program is not being directed to either maximize chances for discovering hydrocarbons or provide for an overall assessment of the hydrocarbon potential of NPRA," the GAO report said. Because the program has attempted both to test major structures for commercially producible oil and gas and to obtain stratigraphic data for the entire 37,000 square miles of the reserve, neither goal has been accomplished.

The program has been rushed by Congressional deadlines of April, 1979, and January, 1980, for completion of studies on the reserve's oil potential and future uses. The GAO recommended in its December report that Interior develop an explicit plan for further exploration, seek an extension of the study deadlines, and consider allowing private industry to conduct any additional exploration and development as a way to cut costs.

The Carter administration apparently ignored the report in recommending to Congress that drilling be halted this September, a year ahead of schedule. "My personal recommendation is that we put it on the shelf and wait to see if it is needed," Interior Secretary Cecil Andrus told a congressional committee.

But the administration's proposed cutback has met stiff resistance in Congress, and it appears likely money will be added to the fiscal 1980 budget for the exploration and assessment program.

Representative Morris Udall of Arizona joined the Alaska congressional delegation and others in support of continued drilling. "In my attempts to prevent oil development of the Arctic Wildlife Range, I point out there are plenty of other sites in Alaska for oil exploration and production," Udall said. "One of those sites is the NPRA."

Alaska Senator Ted Stevens called the administration's plan to end exploration "one of the worst decisions I've ever seen in my years in government" and threatened to use it against President Carter in the 1980 presidential campaign.

Royalty Oil and Gas Development

ALPETCO OUTLINES PRODUCT SLATE

ALPETCO, which has a contract to purchase Prudhoe Bay royalty oil for use in its planned refinery and petrochemical facility, says gasoline and jet fuel will be its principal products in the early years of operation.

AGO 532654

ALPETCO President Gordon Cain appeared before the Senate Resources Committee March 8 to brief legislators on the company's progress since last June. ALPETCO is moving ahead with the design and configuration of a facility that will meet environmental and marketing considerations, he said.

Cain said the company's preliminary product slate includes principally no lead gasoline, regular gasoline and jet fuel. The facility also will make enough diesel fuel for the Alaska market, a small amount of heavy fuel oil for sale in the Alaska market three aromatics (benzene, toluene and xylenes), naptha (which eventually will be used as a feedstock for ethylene production), some carbon black and sulfur.

The plant configuration and product output were determined by considerations of (1) the North Slope crude, which is heavy and high in sulfur content, and (2) the West Coast market, which has a surplus of residual fuel oil and little demand for home heating oil, Cain said. Cain stated that the presently proposed plant design and output would help solve critical problems, because (1) ALPETCO will produce no lead gasoline, which is in short supply; (2) ALPETCO will not contribute to the West Coast residual fuel oil surplus; and (3) ALPETCO will use 150,000 barrels a day of crude which otherwise would have been surplus on the West Coast and would have to be shipped to the East Coast at considerable cost.

When questioned, Cain said he anticipated that downstream petrochemicals, such as styrene, phenol and ethylene products, would come on stream two years after the refinery/petrochemical complex had been in operation.

Cain indicated that the fuels products would be marketed on the West Coast, and the petrochemicals would be sold in Japan, South Korea and Taiwan, as would be the naptha, provided an export permit could be obtained.

ALPETCO and its environmental consultant are continuing to work closely with the Department of Environmental Conservation and the Environmental Protection Agency in the preparation of the draft Environmental Impact Statement, which is due in October of this year.

Cain said ALPETCO expects financing arrangements for the facility to be completed in the near future. ALPETCO believes it will have long-term contracts for 90 percent of the product output signed by mid-summer, he said.

As expected, Natural Resources Commissioner Robert LeResche approved Valdez as the site for the proposed facility on March 5.

GAS LIQUIDS AND ROYALTY GAS PIPELINE STUDIES PROPOSED

Appropriations for engineering feasibility studies of gas liquids and royalty gas pipelines from Prudhoe Bay to tidewater appear likely to be approved by the legislature this session.

The Senate unanimously approved a $275,000 appropriation (CS SB 128) March 19. The Senate bill would give the Legislative Council $200,000 to be used by the Senate Resources Committee in studying the engineering feasibility of a gas liquids pipeline, and $75,000 to be used by the Legislative Council Interim Committee on Rural Energy Policy in evaluating the benefits of in-state use of royalty gas.

A similar House measure (CS HB 239) appropriating $450,000 for gas liquids and royalty gas pipeline studies has been approved by the Resources and Finance committees, and is pending in the Rules Committee. The House bill is sponsored by 33 members.

Consultant Joe Moore of Bonner & Moore Associates, Inc., earlier recommended an engineering feasibility study of a gas liquids pipeline as a way to help the state promote development of a petrochemical industry. (See Energy Background Report #4, Feb. 1, for details.)

Other

LEGISLATURE CONSIDERS HYDROELECTRIC FUNDING

An $8.1 million appropriation to fund feasibility studies for the Susitna hydroelectric project, and a $7.3 million appropriation for four other hydroelectric projects, are pending in the legislature.

The Senate in February approved an $8.1 million special appropriation to the Alaska Power Authority to be used as a reserve to guarantee tax-free revenue bonds for Susitna Phase I feasibility studies, which will cost at least $25 million.

The Internal Revenue Service said in March it would not approve the authority's financing scheme; the authority then began examining other approaches in an attempt to keep the four-year Phase I studies on schedule. One suggested approach was to ask voters to approve a $25 million general obligation bond issue for the studies, but questions were raised about the legality of issuing g.o. bonds for studies.

The authority decided April 9, based on recommendations from the governor's Devil Canyon Task Force and interested legislators, to seek an $8 million direct appropriation from the legislature. Expenditure of the money would be contingent on one of two things happening:

1. Senator Mike Gravel is successful in achieving passage of federal legislation to guarantee federal reimbursement for state money spent on the Phase I studies if the project is determined not feasible; or

2. If Senator Gravel fails to get such legislation passed, a reasonable alternative program has been developed to construct the project without federal participation.

"Absent some completely unforeseen event occurring, the general fund would be the only source of funds available to finance either approach, but might be paid back if Gravel's plan is approved," the governor's task force said in a memo. "In either proposal, the money required could become part of the project financing if the project is constructed."

The authority will develop alternate approaches, considering construction by both the Army Corps of Engineers and private firms, between now and the end of the 1979 congressional session, said Terry McGuire, a financial adviser to the authority.

McGuire said the problems in designing a workable and legal financing plan have put the project substantially behind schedule. The authority earlier had requested prompt legislative action so the corps could proceed with field engineering studies this spring and summer. Some of the lost year can still be salvaged if the appropriation is approved quickly enough to get biological studies underway by summer, McGuire said.

The Susitna appropriations bill and a companion resolution are pending in the House Resources Committee.

The House already has approved $7.3 million for the Alaska Power Authority's revolving fund for hydro projects in Ketchikan ($3.1 million), Kodiak ($2 million), Cordova ($250,000) and Wrangell-Petersburg ($2 million). Those appropriations are pending in the Senate Finance Committee.

RURAL ENERGY COMMITTEE PLANS CONFERENCE

The Legislative Council's Rural Energy Committee is planning a conference on state energy policy alternatives May 16 and 17 in Anchorage.

The committee, chaired by Senator Frank Ferguson of Kotzebue, has retained Alaska Native Foundation President Roger Lang under a $48,000 contract to organize the conference, which will bring together consumers, planners, regulators, producers, utility companies and others concerned about developing a long-range state energy policy.

"There's no plan now," Lang said. "Our plan seems to be to move our oil and gas resources out of the state as quickly as possible. Is that what people want? ...Citizens ought to be getting some benefit from these resources besides money into the state treasury."

Lang said he expects that issues such as the high cost of home heating, the lack of in-state oil and gas delivery systems, and the role of coal and hydroelectric power will be discussed at the conference.

The committee plans a second meeting in September or October to develop recommendations for the governor and the legislature based on the findings of the May conference, Lang said.

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

AN OVERVIEW OF NATURAL GAS AND GASLINE ISSUES

By Kay Brown, Assistant to Senate President John L. Rader

and

Connie Barlow, Assistant to Natural Resources Commissioner
Robert LeResche

April 20, 1978

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CHAPTER

I. INTRODUCTION

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

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

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

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

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

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

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

II. WHO IS INVOLVED?

The principal actors in the gasline debate are:

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

GAS PRODUCERS AND OWNERS

A. Gas Producers

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

OIL & GAS PRODUCERS

Company	%Gas Cap Gas1	%Solution Gas2	%Total Gas3	%Total Oil
SOHIO	15%	53%	27%	53%
ARCO	42%	20%	36%	20%
EXXON	42%	20%	36%	20%

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

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

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

B. Gas Owners

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

GAS & CRUDE OWNERS

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

GAS PURCHASERS

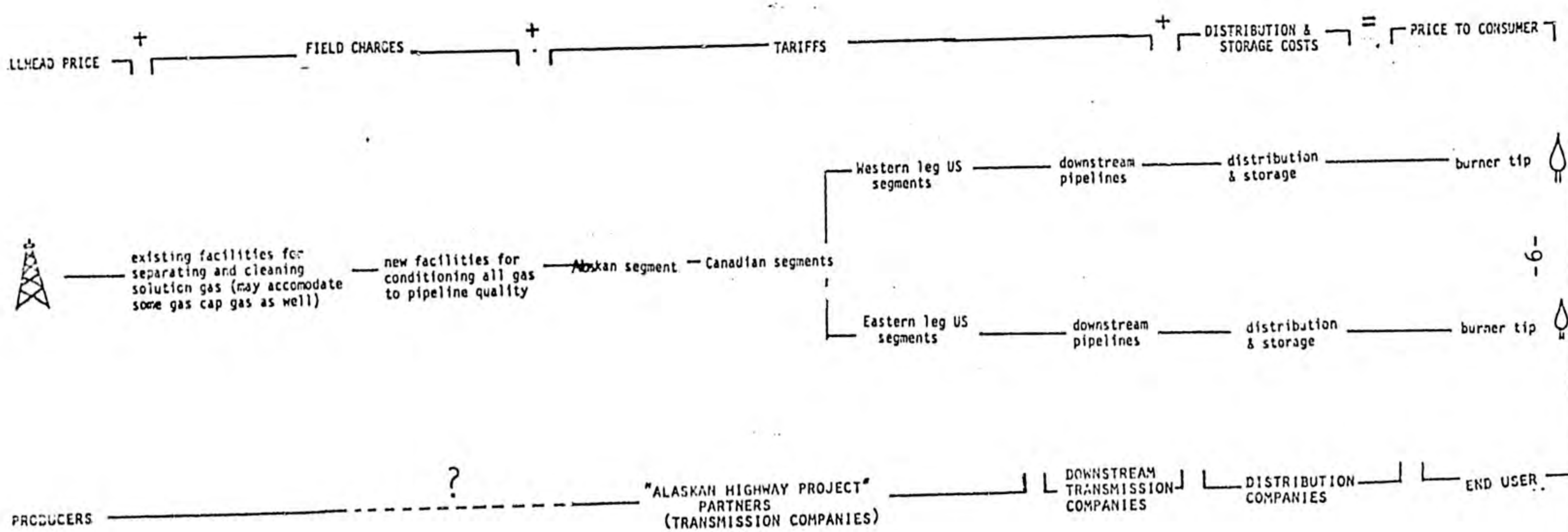
A. Potential Purchasers

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

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

TRACKING THE FLOW OF GAS FROM THE WELLHEAD

TO THE CONSUMER BURNER TIP



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

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

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

POTENTIAL PURCHASERS

Interstate Gas Transmission Companies

Gas Distribution Companies

Petrochemical, Fertilizer and Methanol Companies

State of Alaska

B. Conditions Affecting Sales to Purchasers

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

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

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

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

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

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

CONDITIONS AFFECTING SALES TO PURCHASERS:

Economic/Marketing

State Policy for sale of its royalty gas

Federal regulation:

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

TRANSPORTATION COMPANIES (Pipelines)

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

A. Gas Purchasers' Involvement in Pipeline Ownership

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

B. Gas Owners' Involvement

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

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

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

C. Federal Government Involvement in Pipeline Ownership

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

POTENTIAL PIPELINE OWNERS

Gas Purchasers (Pipeline and distribution companies)

State of Alaska

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

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

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

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

*

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

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

ORGANIZATION OF THE "ALASKA HIGHWAY PIPELINE PROJECT"

(1) Alaskan Northwest Natural Gas Transportation Company

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

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

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

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

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

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

(2) Pacific Gas and Electric (existing company)

(3) Pacific Gas Transmission Company (existing company)

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

(5) Foothills Pipeline (S. Yukon) Ltd

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

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

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

Westcoast Transmission (49%)

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

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

Alberta Gas Trunkline (49%)

(8) Foothills Pipeline (Alberta) Ltd.

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

Alberta Gas Trunkline (49%)

(9) Foothills Pipeline (Saskatchewan) Ltd.

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

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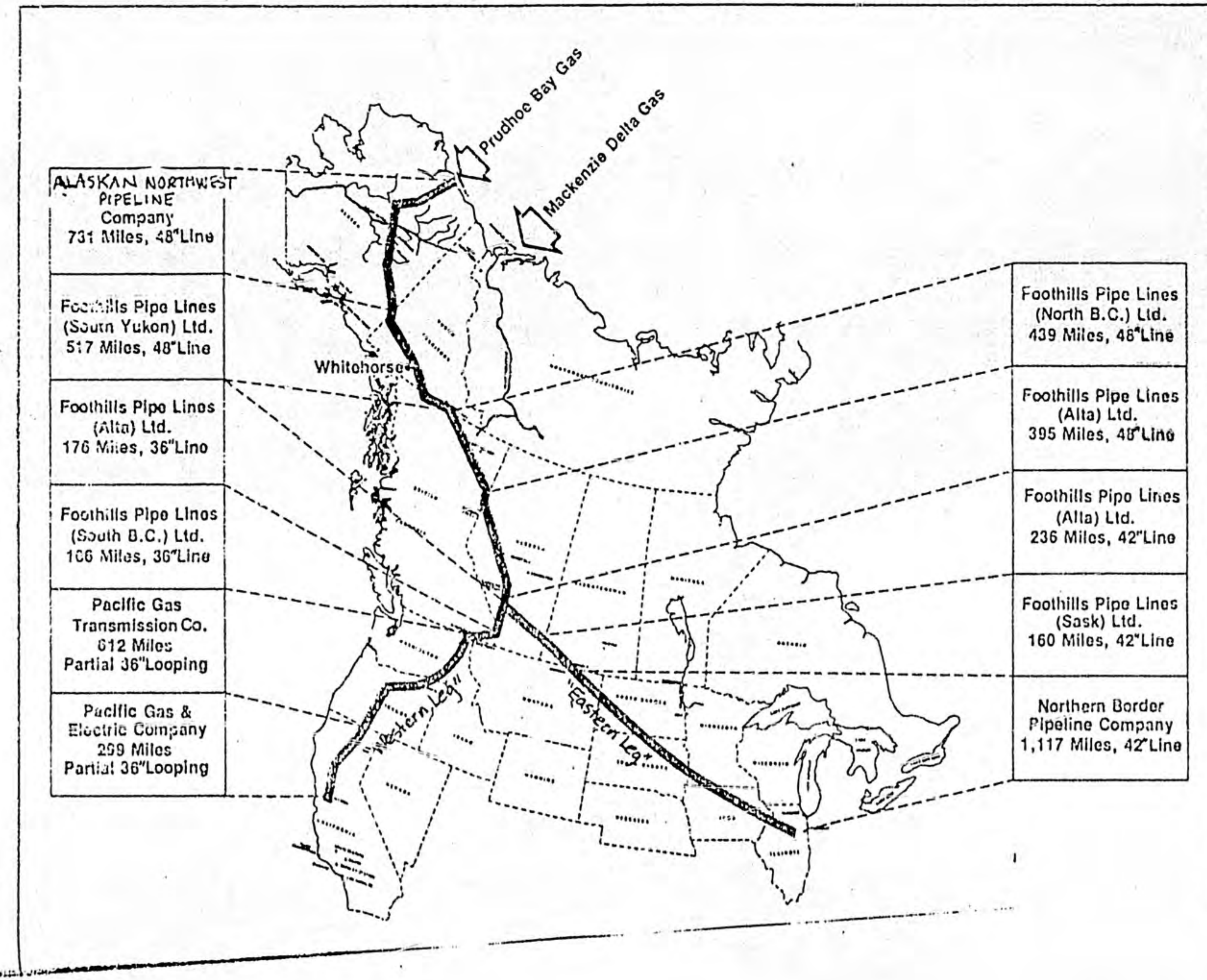
[1] Foothills Pipeline (Yukon) Ltd. maintains at least a 51% interest in each of the 5 "Foothills" pipeline consortiums. It is composed of 50% Alberta Gas Trunkline and 50% Westcoast Transmission.

COMPONENTS OF THE "ALASKA HIGHWAY PIPELINE PROJECT"



LENDERS

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

A. Investors in Production Facilities

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

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

B. Investors in Transportation (pipeline) Facilities

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

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

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

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

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

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

POTENTIAL INVESTORS IN FIELD PRODUCTION FACILITIES

Equity:	Producers
Debt:	Private State

POTENTIAL INVESTORS IN TRANSPORTATION (PIPELINE) FACILITIES

Equity: Pipeline Companies
State

Debt: Private
State
Producers (highly unlikely)

LANDOWNERS

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

GOVERNMENT REGULATORS

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

The United States

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

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

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

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

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

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

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

Economic Regulatory Authority: The Economic Regulatory

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

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

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

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

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

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

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

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

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

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

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

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

What about ECONOMIC WASTE?

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

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

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

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

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

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

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

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

Canada

Parliament: An Agreement between the United States of

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

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

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

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

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

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

BACKGROUND

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

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

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

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

A. Gas Quality

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

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

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

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

1. Transport of Gas Liquids in TAPS

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

a. Physical Constraints for Transport of Liquids in TAPS

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

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

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

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

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

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

*

b. Economic Constraints for Transport of Liquids in TAPS

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

2. Transport of Gas Liquids in the Gasline

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

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

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

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

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

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

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

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

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

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

WHAT ARE WE TO DO WITH HALF THE BUTANES? ALL THE PENTANES?

3. Other Quality Considerations for the Gasline

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

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

Reasons to remove the CO2:

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

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

Reasons to not remove CO_2:

methanol
ethanol

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

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

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

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

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

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

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

B. Volume of Gas

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

1. Production Rate

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

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

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

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

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

2. Gas Sales

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

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

PIPELINE DESIGN

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

A. Volume Capacity

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

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

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

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

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

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

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

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

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

B. Quality Specifications

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

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

(2) impurities - specifying the maximum amount of CO2 and H20 that may remain after conditioning of the raw gas.

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

(4) pressure - specifying the required compression necessary.

C. Placement Above or Below Ground

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

FIELD ACTIVITIES

(including gathering, conditioning, and water injection)

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

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

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

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

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

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

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

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

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

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

IV ECONOMIC CONSIDERATIONS:

PIPELINE FINANCING, GAS PRICING, AND TARIFFS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The President's Decision

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

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

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

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

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

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

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

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

Marketability and Economics

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attitude of North Slope producers concerning financial participation:

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

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

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

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

Pricing Methods

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

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

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

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

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

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

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

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

thus further impeding marketability.

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

20-Year Average Alcan Delivered Cost
(1975 dollars)

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

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

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

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

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

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

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

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

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

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

price.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

V. TIMING AND RELATIONSHIPS OF GASLINE EVENTS

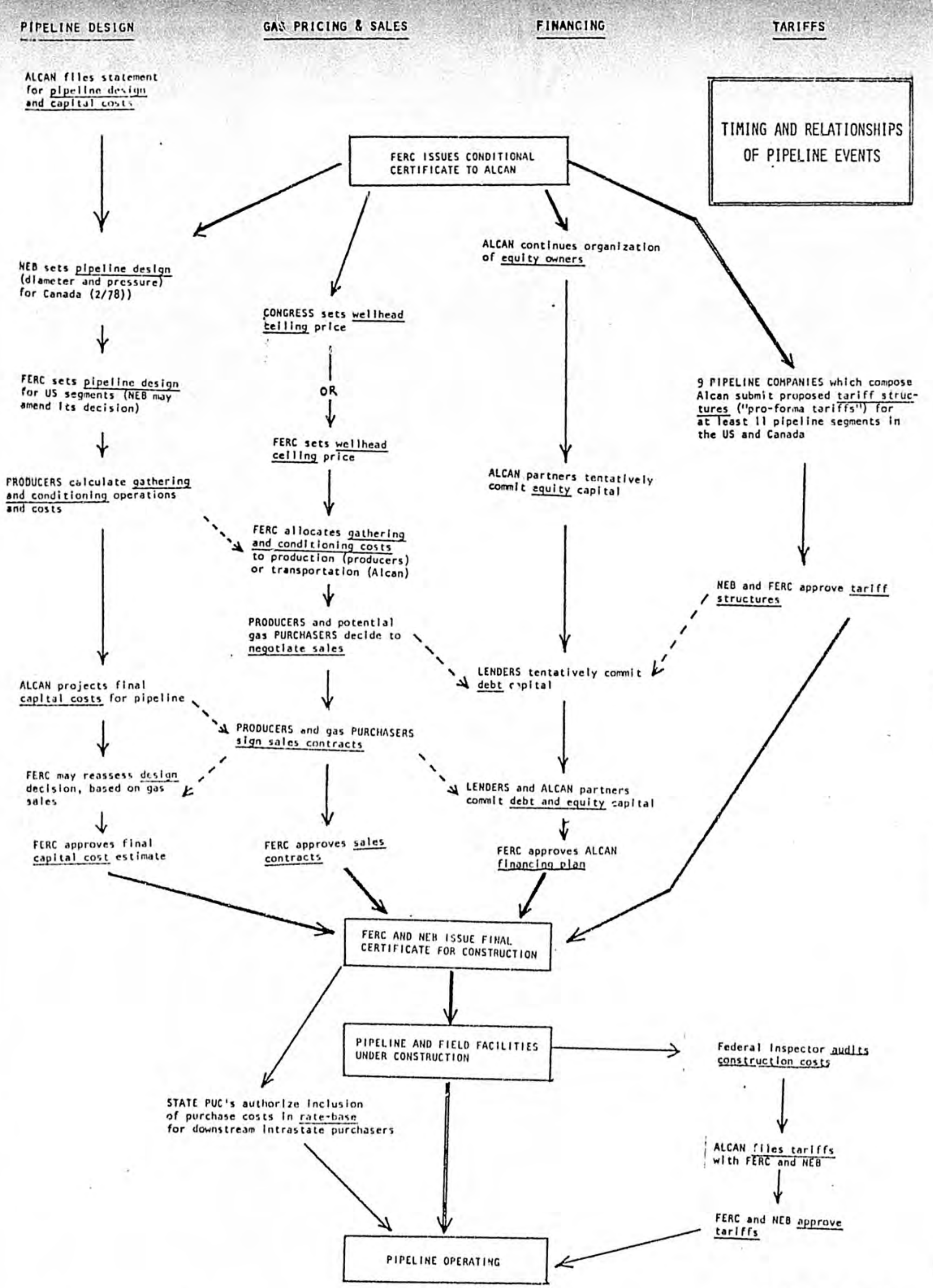
An understanding of the sequence and cause-and-effect relationships of the various gasline events provides the perspective for dealing with any particular issue. The attached diagram attempts to portray these events and relationships. While it demonstrates that their progression is by no means a single,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

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

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

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

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


PIPELINE DESIGN
GAS PRICING & SALES
FINANCING
TARIFFS
TIMING AND RELATIONSHIPS OF PIPELINE EVENTS
ALCAN files statement for pipeline design and capital costs
FERC ISSUES CONDITIONAL CERTIFICATE TO ALCAN
NEB sets pipeline design (diameter and pressure) for Canada (2/78))
CONGRESS sets wellhead ceiling price
OR
FERC sets wellhead ceiling price
ALCAN continues organization of equity owners
9 PIPELINE COMPANIES which compose Alcan submit proposed tariff structures ("pro-forma tariffs") for at least 11 pipeline segments in the US and Canada
FERC sets pipeline design for US segments (NEB may amend its decision)
PRODUCERS calculate gathering and conditioning operations and costs
FERC allocates gathering and conditioning costs to production (producers) or transportation (Alcan)
ALCAN partners tentatively commit equity capital
NEB and FERC approve tariff structures
PRODUCERS and potential gas PURCHASERS decide to negotiate sales
LENDERS tentatively commit debt capital
ALCAN projects final capital costs for pipeline
PRODUCERS and gas PURCHASERS sign sales contracts
FERC may reassess design decision, based on gas sales
LENDERS and ALCAN partners commit debt and equity capital
FERC approves final capital cost estimate
FERC approves sales contracts
FERC approves ALCAN financing plan
FERC AND NEB ISSUE FINAL CERTIFICATE FOR CONSTRUCTION
PIPELINE AND FIELD FACILITIES UNDER CONSTRUCTION
Federal Inspector audits construction costs
STATE PUC's authorize inclusion of purchase costs in rate-base for downstream intrastate purchasers
ALCAN files tariffs with FERC and NEB
FERC and NEB approve tariffs
PIPELINE OPERATING

AGO 532728

VI. IMMEDIATE STATE CONCERNS

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

A. Timing of Royalty Sales

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

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

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

There are several approaches to this dilemma:

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

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

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

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

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

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

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

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

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

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

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

* * * * * *

Timing of Royalty Sales - Putting it in Perspective:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Reasons to act now:

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

being financed will diminish significantly.

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

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

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

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

Reasons not to act now:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SELECTED REFERENCES

Unless otherwise noted, the following reference materials are located in the Commissioner's Office, Department of Natural Resources, Office of the Senate President or Legislative Research.

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Natural Gas Act of 1938

Alaska Natural Gas Transportation Act of 1976

"Approving the Presidential Decision on an Alaskan Natural Gas Transportation System" (SJ Res. 82; HJ Res. 621) (Senate Report 95-567; House Report 95-739) 1977

"Agreement Between the United States and Canada on Principles Applicable to a Northern Natural Gas Pipeline" 1977

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Decision and Report to Congress on the Alaska Natural Gas Transportation System; Executive Office of the President; 9/77, 271 pp.

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Analysis of Transportation Proposals for North Slope Natural Gas; Arlon Tussing; 3/75; 45 pp.

Report of the Attorney General; July 1977; 100 pp (antitrust).

PIPELINE DESIGN/ENGINEERING

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

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

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

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

ROYALTY GAS

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

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

MISCELLANEOUS

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

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

(1) Unit Agreement

(2) Operating Plan (2 volumes)

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