

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 86 / 2

460 SCOMM13: JOINT COMM. ON GAS PIPELINE IMPACT 1974-76

A: No, I don't. I don't have anything useful to give you at all. If I were pursuing this, I would be sure to talk to some people who would be getting the gas out of your all-Alaskan line. I would assume that would affect states like Arizona, California, New Mexico, and all the states, and maybe Texas, that would benefit from deliveries of gas to the West coast of the U.S. I don't know if you are doing this, but this is the most successful thing we've been able to do is go find states that have an interest in what we're trying to do.

Q: In that regard, you may have heard of the two proposals of displacement of gas that now moves to California, El Paso particularly, would move it to the Mid-west and the East. What dangers would you see in that? You talked earlier about the possibility of curtailment.

A: What dangers that I would see if your gas was moved to the East coast?

Q: We don't care once we sell it, but do you think that is practical? Do you think the people back East would buy it?

A: Yes, I'm sure all of you have seen this map. It is a map of major natural gas pipelines--you will see that you can move gas anywhere in the populated areas. If your gas comes in the West coast, you have existing lines, where the flow would have to be reversed. I know El Paso stated in one of the exhibits I read, that this was no problem.

Ok, once you get this gas down into this area, into Texas or Louisiana, you've got a spaghetti bowl of pipelines that will permit that to go anywhere. So my answer is, I think would be all over the United States.

Q: In meeting with the California coastal Commission people, they were talking about converting that line to an oil line going the other way in order to get additional refining...with that in mind is there sufficient passage to California, Texas, Oklahoma, Louisiana to handle the gas?

A: I don't have the technical knowledge to answer that. My impression is that if you reversed the direction you can do this. I know Texas, Arizona, New Mexico gas is going to California. If they're getting your gas and don't need your gas...judging from the position by El Paso, you could reverse the flow of that gas....I think you have a tremendous number of allies in the U.S. that you might not be using. If you send a delegation to meet with a Commissioner or somebody else or congressman. Here, I can't over emphasize, here is a mass of people out here you're not communicating with. And they are the guys that are going to make all the decisions.

Q: (garbled)

A: I would think that first of all your Legislature could possibly pass some very restrictive legislation--part of which

may be unconstitutional. You're entitled to try and build your own pipeline. You've got a long hard way ahead of you with many different battles and you're going to have to face each one as you go along. Each time you take a position to make it more practical or more feasible or easier to leave the gas here and more difficult for people to absorb your gas in the lower 48, you've got the best hope of success.

Q: Could you go into some detail some of the legislation whereby Louisiana taxes gas and then gives the rebate to those who use it.

A: It does not do that any more. WE had a law for that purpose but really we got short of gas, and we saw no reason for the rebate because we don't have any gas for anyone to use, But for the period when the law was effective, it provided that if you had an industry in Louisiana using natural gas, you got a refund against your other taxes. If you put a tax on all gas--but if an industry used gas in Louisiana, he got some special tax concessions of a significant amount.

Q: (garbled)

A: No, Louisiana has a severance tax on all gas produced.

Q: You talked about the gas from the North Slope already being Committed, from your experience from a producers standpoint, then he has some escape in his contract if he can't deliver? If he has his gas committed to a utility or another gas company in the East coast--if he can't deliver, he's not going to be penalized if he couldn't go ahead and fulfill it--it's a continued sale, isn't it?

A: No, I can't say that. If you passed a law that directly interfered with Interstate commerce, I think you would lose.

Q: I'm not talking about that--but rather our continued sale. I'm questioning the emphasis we're placing on the fact that people would say, we've already sold that gas.

A: I'd like to comment on that. Could anyone tell me if the Alaskan Regulatory Commission regulates the drilling and operation on your leases(?) I include in that question a reference to how the wells should be drilled, the whole bit.

Down in Louisiana, we find that if we can create as much muscle as possible, we hardly have to use it. In fact when handed all these things to the Governor, I was asking the Legislature how we were going to apply. I said I hope we never have to use it. I think it's so restrictive that I really don't think we have to use it. But, if someone won't play ball, we will use it--and we had almost no opportunities to use it, because everybody plays ball. You're sitting

there with one board pointed by the governor that's regulating how many wells you should drill--and another agency appointed by the governor that gives you well permits and really regulates the physical drilling of the well. If you have those two things under firm control, you've got an awful lot of muscle. If you don't have as much as you like, maybe you ought to pass some laws and create some more. We're pretty reasonable people..... Let me give you an illustration of what we did last week. At the Southern Governor's Conference, I think it was Gov. Edwards, ...he needed 20 million cubic feet of desert(?), nothing; they had some glass manufacturing plants, and textile mills, and some thousands of people would be out of work this winter if they couldn't get some gas. Gov. Edwards said, we'll get you some gas. The political realities in Louisiana is that we need North Carolina's votes bad. You heard the figures, we're short of gas. But, our best hope of getting gas, is to get people like North Carolina going with us. The Governor said, you get them some gas. We invited about 30 companies to come in. We explained our problem and at least six people stood up and said they'd be delighted to help. We didn't make anyone do anything. In fact, one guy said, I understand the political realities of what you are trying to do--you want some votes from these people.
(end of tape)

MEMO: Members of the Gas Pipeline Impact Committee
FROM: Eric Eckholm
RE: Discussion of Gas Pipeline with Department of
Interior officials.
DATE: 10/31/75

PLAYERS: John Latz, DOI
Burke Riley, DOI
Clark Gruening
Pat Rodey
Staff

Riley apologized for short notification stressing informal and not official briefing. Latz did all the talking. He is an engineer for DOI, and seemed very knowledgeable. He said:

1. Gas pipeline by either route is financially desirable.
2. Neither route has financing capability at this time
 - a) Arctic route would need federal subsidy or guarantee.
 - b) El Paso is not at all credible unless they get financially sound partners.

This lack of sound financing is partially the reason why the Federal Power Commission is not rushing to make a decision.

The industry will probably make some readjustments in gas ownership to insure financing capability for a pipeline.

- a) At present, North Slope gas is optioned out to 8 gas companies who are behind the Gas Arctic proposal.
- b) Cost of the pipeline will be shared in proportion to ownership of gas. Principal present owners of gas cannot finance pipeline.
- c) Tenneco Gas is the largest gas company in the world, and probably only company able to come up with financing necessary for construction of the pipeline.
- d) Whichever line is able to come up with sound financing will probably swing rest of owners behind it, thus taking competitive bids for line.
- e) Exxon wants to build Canadian line because of McKenzie Delta gas, which they own most of.

Latz indicated the State's royalty gas is critical at this point in time. The Canadian line is not feasible for at least two years according to DOI. Each 1 year delay means 10% loss of economic desirability for either line.

His suggestion for state posture, if we decide we want an Alaskan line--commit royalty gas with qualifications:

1. Gas available only to the extent that the State doesn't need it for in-state use.

2. Committed only if purchaser insures pipeline is built through Alaska. He also indicated industry assurance that we would not do the same thing we did to the oil industry; reserves tax, was necessary.

He stressed he did not advocate committing to Tenneco, that if the state committed to anybody (i.e. El Paso), that they would then cut a deal with Tenneco to insure financing.

He also indicated that time was critical to maintaining favorable state position.

Latz"s general comments:

- 1) Keeping our gas in the ground is not a possibility. It uses up gas, we do not own the resevoir, and need to come up with a lot of financing for the equipment.
- 2) The lower 48 market will accept any \$3 per million cubic feet gas it can get according to Arctic's marketing people.
- 3) Anything over 50¢ wellhead price is profitable enough for the line.
- 4) 400 million barrel loss of oil by 2000 A.D. will accrue due to gas production, but this is insignificant compared to gas revenues.
- 5) Nobody in the industry or government has ever done this before...nobody's sure what is going to happen...

Mr. Latz stressed that these are only his opinions, not DOI policy, these are rough notes from his qualified opinions.

11/7/75

Memo: To the file
From: Eric
Re: Meeting with Pat Dobey, Div. of Oil and Gas

Main Points

- A) State should not commit royalty gas at this time
- B) Keeping the gas in the ground is an option
- C) Industrial development in Alaska is a very real possibility
- D) The country is running out of gas and oil, prices will only rise.

Explanation

- A) The state should not commit royalty gas at this time.

Past history has shown that if we commit our gas to go out of state, we may not be able to use it in-state if we later want to (FPC ruling in Louisiana). To commit our gas now might preclude later development in state.

- B) Keeping the gas in the ground is an option.

As the gas is produced, we can count 12.5% as credit, not taking any of the gas. At a point when the reserves are estimated to be down to only our share, we could cut off production.

This has not been done before. We run the risk of 1) accepting reservoir estimates, and possibly not getting the amount of gas we are entitled to, or 2) having the US nationalize the gas and taking it away. It would not involve reinjection, if we just did not produce it.

- C) Industrial development in Alaska is a very real possibility.

The cost of gas is spiraling. Gas in California is spiraling. present costs are in the neighborhood of 50¢ Mcf in Alaska, and \$2.00 Mcf in California. If industry can purchase guaranteed quantities of gas at 1/2 or 1/4 the rate, immense savings can result (in the neighborhood of \$30M a year for a petrochemical plant). This savings will probably more than offset the cost of transportation, and added labor and construction costs, which are escalating at a much slower rate than gas.

- D) The country is running out of gas and oil, prices will only rise.

It is a fact that the reserves in this country, and around the world are running out. Some countries are talking more often about significantly cutting production to maintain reserves. 40 years is the number Dobey mentioned more than once for supply of major reserves. California is going to be faced with critical shortages in 2 years. The country is hungry for natural gas. If Alaska uses it's gas to sell outside the state, our resources will be depleted in 15--25 years. According to Dobey, around 199- the state will begin to face shortages. Due to nationwide shortages, and geography, Alaska will probably be unable to purchase gas elsewhere--"We'd better hang on to what we've got."

Memo: To the file

From: Eric

11/11/75

Re: Arlon Tussing seminar/Alaska Industrial Development Council

A brief history on Alaska Oil and Gas use, and possible direction;

"The era of cheap energy is over"

Main Points regarding North Slope Gas;

- 1) It is not economical to produce North Slope gas.
- 2) De-regulation of gas in lower 48 would make production of North Slope gas less feasible.
- 3) Either line will probably need some federal subsidy to be completed.

Explanation:

- 1) Neither line is economical.

Tussing said he studied ~~all~~ major construction projects in the past, and they run approximately twice as expensive as anticipated. This would mean a price of \$16 to \$20 billion for the Gas line, either route. Here is his projected scenario;

The FPC gives a go ahead to either route, and allows companies to charge interest on their construction loans to current consumers--A portion of the line is funded, \$3 or \$4 billion in loans from private industry with projected cost of \$8 to \$10 total.

--By about 1979 the preliminary work is done, the main financing is needed, but the cost has risen to \$14+ billion--financing companies want proof that gas can be sold with solid contracts at a price to cover the cost of the line. The price is too high to guarantee sales.

--The constructors of the line go to congress to get bailed out and obtain financing for the rest of the line.

--Congress provides a subsidy, but the wellhead value is negative. the state receives minimal price for taxes or royalty gas.

--In this case, the Alaskan line is economically beneficial to Alaska, considering revenue from building the line, and possible industry attracted by cheap gas at tidewater, before liquifaction.

- 2) De-regulation of Natural Gas would adversely affect North Slope production.

Effects of De-regulation

- a) supply will increase.

--price will rise to intra-state level (FPC inter-state price is 52¢ Mcf. Intra-state price is about \$2.00 Mcf)

--Horded gas will be sold

--more gas will be tapped

b) Existing lines interstate will be able to compete with intra-state prices, and the non-producing states will have their shortages eased.

- c) Demand will go down.

--As price rises, some consumers will switch to other fuels--at present, 50% of natural gas is used as boiler fuel, this would be cut down as price rises.

All other things equal, the demand for Alaskan gas would go down. --Alaskan gas is going to be expensive. With regulated price, expensive Alaskan gas can be used to supplement cheaper, regulated southern gas. The price can be "rolled-in" to maintain a competitive price with other forms of energy, especially coal. If gas is de-regulated, there will be no "cheap" gas to average the price with, and the High cost of North Slope gas would keep it out of the market.

3) Either line will probably require a federal subsidy --see scenario for 1). Line costs will be prohibitive for private financing, and not be worthwhile to produce unless congress provides subsidy.

Memo: To Committee members

From: Eric

Re: Suggestions for gas use, speaker didn't want his name used.

11/12

- 1) Severance tax increase incrementally according to revenue lost if Canadian Line is OK'd by FPC
- 2) Severance tax tied to price index
- 3) equity ownership of Pipeline rather than cash contract.

1) If the FPC goes with Canadian line, raise Alaskan Severance tax to cover economic opportunity lost to the state;
If we determine the Alaskan Line will produce 15 times the revenue the Canadian line will, then raise the severance tax 15X to cover our losses.

2) Structure the severance tax so that we are insured some return. Set a % and a base price, and tie it to a price index to compensate for increasing market value.

--The FPC might set an unreasonably low wellhead price on the gas, from Alaska's viewpoint. If Alaska makes the tax something like 10% per X, or 5¢, whichever is greater--we are assured of some return.

--Prices are skyrocketing for gas. If we make a deal today, we may get shafted tomorrow. severance tax should be tied to at least one or possibly several price index--gas price intra-state, inter-state, or wholesale price index--insure we maximize returns.

3) equity ownership of a pipeline. (watch out, hot topic)

The state of Alaska assume joint venture with industry for construction of pipeline. Serves several purposes;

--Once we make a cash deal for our royalty gas, there is a very strong possibility that it might be deemed inter-state commerce, and we would be giving up any chance of future in-state use, no matter where the line goes.

--We make a deal for partial cash payment, and say 25% equity of line, and 25% equity of ~~new~~ LNG tankers. We get;

a) A cancellable contract if the line does not go through Alaska, which we might not have with a cash contract.

b) Increased financial backing for an Alaskan line--the financing is minimal now, with state support the financing is ~~may be~~ enhanced, we recover whatever we invest with taxes very quickly, without cash outlay.

c) A continuing revenue source ~~at~~ at a rate of return that is attractive--12%--14% on line, and LNG tankers are not regulated, so their return will be probably higher. This money cannot be squandered, and would provide steady, bankable revenue for the state.

Problems

--Obviously political dynamite--state participation in private industry

--possible mismanagement due to political partisanship rather than corporate profit seeking

But--this would be controlled by private industry, with the state as only a minor stockholder--would give state leverage and \$\$

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

Memo: Committee members
From: Eric
Re: Tenneco meeting
11/13/75

Tenneco has proposed to buy the state's royalty gas.
They offer; \$100,000,000 front end money

- they will pay the interest
- Alaska will pay by future oil or gas income
- They will support Alaska route

--\$100,000,000 front end money.

They will give us the money even without FPC allowance to pass on the cost of the money to their present consumers. El Paso's offer is contingent on FPC allowance to pass on costs.

They say we can back out if Alaskan route is not given FPC Go-ahead. There is some question if this is possible with the FPC once a contract has been signed..i.e. if we commit our gas contingent on obtaining an Alaskan route, and we accept some cash for it, if the line goes Canadian, we might not be able to then back out of the contract.

-- We would pay back the principal, not the interest out of our future oil or gas revenues.

--They want a commitment of at least 90% of the royalty gas before they will sign a contract. They say that supporting the Alaskan route will cost considerable money, and that they need at least 90% of the gas before their company will consider backing an Alaskan route. They say that there are undoubtedly other gas reserves in Alaska that will be able to take care of our in-state future needs as they arise.

--Tenneco sees the next 4--6 month period as critical in obtaining a go-ahead on the pipeline. With the stalemate of an energy policy in Washington, the only way the country can further "Project Independence" is to push for quick availability of Alaskan Gas. With the country facing a gas shortage this winter, and an election coming up, the decision can be made soon, possibly with congressional override of FPC's right to determine route. After this period, the variables are too great to determine what might happen. Tenneco is willing to push for Alaskan route if they get commitment soon.

--El Paso is so far into the project they will continue to be involved even if we commit gas to Tenneco. Tenneco did not specify what involvement El Paso would have, or their plan for building the line, or their strategy for getting the decision for an Alaskan route. They are the largest gas company in America, and are financially as viable as all the major Gas Arctic people combined.

--personal observation Tenneco is gambling. They seem to think the Alaska route is possible. They have not put very much into their proposal or their discussions with Alaska. They are asking the state to commit 90% of our royalty gas, but they have yet to show strategy plan for getting Alaskan line, or construction plan for the line, if approved. We need more information...

Tennessee Gas Transmission
A Tenneco Company



Robert C. Thomas
Vice President

Chamber of Commerce Building
P. O. Box 2511
Houston, Texas 77031
(713) 223-2275

August 23, 1975

Mr. Guy R. Martin, Commissioner
Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99901

Dear Mr. Martin:

In response to communications with Alaskan officials, Tennessee Gas Transmission, a Tenneco Company, has been developing a method for contracting the royalty reserves owned by the State of Alaska in the Prudhoe Bay Field. We have designed a method which provides the necessary benefits to Tennessee Gas and we request your evaluation of the benefits which can be derived by the State. We are attaching a memorandum which outlines the framework of our approach in some detail.

In our opinion the key issue involved in the sale of the right to contract this gas is the routing of the gas pipeline from Prudhoe Bay. If the State desires the pipeline to cross Alaska, the royalty gas should be contracted to an interstate organization which can supply additional support for this route. We feel the State, with this new support and combined with existing backing, can successfully influence the routing of this market outlet. This could protect the future of Alaska through creation of jobs and insure that progress is achieved in a manner consistent with the Alaskan way of life.

In summary, our proposal would allow the State to receive:

1. Support for a trans-Alaskan system.
2. An initial cash payment to be repaid at a later date.
3. A portion of the gas for use in Alaska.
4. Maximum permissible wellhead price.

The company would receive:

1. The right to contract for the purchase of the State's Prudhoe Bay royalty gas.

Mr. Guy R. Martin, Commissioner

August 28, 1975

Page 2

2. Recovery of their initial payment to the State at a later date.

With the publication of the Department of Interior study concerning the relative merits of the alternate market systems, time becomes more critical. Decisions will be made in the near future which will affect the pipeline routing. We do not feel that rumor of a U. S. - Canadian agreement dictates a Canadian routing because the basic problems confronting this route have not yet been solved. Our analysis of the facts now indicate a trans-Alaskan route can be completed at an earlier date thereby creating economic benefits for our company, the State and the consumer.

We suggest the State consider a negotiated contract covering all their Prudhoe Bay royalty reserves. A competitive bid sale cannot obtain comparable benefits.

We are prepared to immediately enter into negotiations with the State concerning these royalty reserves. We request a meeting with you after your review of these recommendations. We will be prepared to meet on any acceptable date.



Robert C. Thomas

cc

Attachment

MEMORANDUM

CONTRACTING OF PRUDHOE BAY GAS

STATE OF ALASKA

In late May, 1975, Tennessee Gas Transmission Company received a letter from the Commissioner of Natural Resources for the State of Alaska requesting proposals for the purchase of the State's royalty gas from leases in the Prudhoe Bay Field. We have communicated with Alaskan officials and discussed the needs of the State to be met in contracting the gas and the ability of Tennessee Gas Transmission or the industry to structure a mutually advantageous proposal.

We have reviewed carefully the ramifications of contracting or securing the rights to contract these gas reserves from the State. Our procedure in reviewing this situation was to determine the benefits necessary to us before we could offer to contract the gas and the benefits to be obtained by the State before they could justify the selling of the right to contract their royalty reserves. The benefits listed below represent what is in our best interests and what we assume to be in the best interests of the State.

1. Benefits Which Must Accrue to the State

In order to justify selling the right to contract the royalty natural gas reserves, certain benefits should accrue to the State. The more significant ones considered are:

- a. The company purchasing the right to contract the reserves should be capable of giving maximum support to a market outlet across the State of Alaska.
- b. The State should receive substantial front-end money.

- c. Some of the gas should be available for use in Alaska.
- d. The maximum possible wellhead price should be paid at the wellhead for the reserves when produced.

2. Benefits Which Must Accrue to the Purchaser

There are still unknown timing factors and substantial risks associated with purchasing the right to contract Prudhoe Bay gas. To compensate for these risks, certain benefits must accrue to the purchaser. These are:

- a. The front-end payment must be financeable eliminating the necessity for the company to make a large capital advance in a single year.
- b. The front-end payment must be recoverable at a particular point in time, perhaps out of a percentage of natural gas revenue or other guaranteed type arrangement.
- c. The right to contract all of the State's royalty gas in Prudhoe Bay must be secured. A minor percentage may be reserved by the State for use within Alaska, but if not used will be included with the gas marketed by the purchaser of the rights.

We have worked toward an approach that would meet these requirements.

In the consideration of various methods of financing, three limiting factors immediately surface. They are (1) the constitutional or statutory limitation on State debt for longer than one year, (2) FPC regulations controlling advance payments and their anticipated expiration at year end, and (3) the capital and

debt position of most pipeline companies. The State does not qualify under current FPC regulations for receiving advance payments.

There are several other factors which must be considered in this decision. Plans are now being made for pipeline routing which will drastically affect the future of the State of Alaska. We see the contracting of royalty gas as leverage supporting the routing of the pipeline across Alaska. This leverage will diminish rapidly with time and will completely disappear if not used. Despite the rumors of a U. S. - Canadian agreement covering a Canadian pipeline route being initialled by the two governments, we now feel a trans-Alaska project can be completed at an earlier date thereby creating economic benefits for our company, the State of Alaska and the natural gas consumer. We base this analysis partially on the fact that the Canadian problems related to natives claims and the rights of the Provinces have not been resolved. We question these can be resolved in a reasonable length of time. It is also possible that some type of U. S. Federal assistance in the form of financial guarantees or new legislation will be required for the successful completion of a pipeline. This would be difficult to obtain for a Canadian route.

We feel there are substantial volumes of additional gas to be discovered in Northern Alaska in the future. This future gas will go to market through the route selected at this time. These volumes could be the energy source for future industrial growth within Alaska if the market outlet is now established through the State.

There has been much speculation about the economics of a market outlet for Prudhoe Bay gas and the effect it will have on the future wellhead price of this gas. This speculation is due to the substantial cost overruns being experienced by major engineering projects throughout the world. A recent study by Tenneco indicates the capital cost of the trans-Alaska pipeline

the liquefaction plant, LNG ships, and receiving facilities, when escalated to the year of expenditure, to be \$3.8 billion, or 57% greater than the recently published U. S. Department of Interior study. After adding a \$.50/Mcf wellhead price, this capital cost would yield regasified LNG at the Los Angeles city gate at a cost of \$2.58/Mcf in 1982. If Tenneco's projection of capital costs should be low by a factor of 50%, which is highly unlikely, the Los Angeles city gate price will increase to \$3.54/Mcf. According to our market analysis, however, this gas will be saleable in the interstate market. We do not wish to minimize the problems of financing that relate to the escalating project cost, but the escalation certainly does not render this gas valueless at the wellhead.

A negotiated sale of the right to contract these reserves is the most advantageous method. A competitive bid sale is not appropriate and it cannot accomplish the many objectives nor provide the benefits envisioned. This is supported by the following:

1. A competitive bid sale should be made on a standard basis for all bidders. This is preferable only when all bidders have equal capabilities and price is the only variable.
2. All bidders could not supply the same degree of effectiveness in the support of the Alaskan route.
3. The unknown risk factors such as date of delivery, routing, natural gas regulation in the U. S. and many other factors which must be taken into consideration will result in lower cash bids on a competitive sale. Provision for some of these uncertainties can be made in a negotiated sale.
4. Competitive bidding would suggest the breaking up of the royalty reserves into smaller packages for sale. These smaller reserves would attract neither the cash bids nor the substantial support for the routing that will be required.

We would propose the following approach as one meeting our requirements and interests and accomplishing the objectives we have assumed for the State. We have divided it into four parts for the purpose of review.

1. Pipeline Route Support

As of this date, Tenneco has not actively supported either of the projects designed to deliver North Slope gas. With the securing of the right to contract the State royalty gas and with the current facts now indicating a trans-Alaska system will offer the quickest and most assured method of getting this gas to market in the lower 48 states, we would be prepared to support the Alaskan route.

2. Capital Contribution

- a. Tenneco will make available to the State an amount in excess of \$100 million for the right to contract all of the royalty natural gas reserves in the Prudhoe Bay Field.
- b. These funds will be made available to the State over a three year period according to its needs. The amount of the funds advanced will be dependent upon the drawdown schedule which will be agreed upon by the parties prior to the execution of the agreement.
- c. All financing will be arranged by Tenneco.
- d. There will be no recovery of the advanced funds for a period of three years following the date of the advance.
- e. We will consider that each drawdown will constitute a separate advance, and that such advances will be recovered out of a percentage of revenue from the

royalty gas production beginning three years after the drawdown and continuing over a recovery period of five years. In the event gas sales have not begun by the beginning of the recovery period, the recovery will be made initially from revenue derived from a percentage of royalty oil production until natural gas production begins. According to our interpretation, this advance would not be classified as debt on the books of the State since repayment is to be made solely from a percentage of revenues to be generated by the sale of the State's natural gas and/or oil.

3. Gas Available for Alaskan Use

Tenneco recognizes that some of the State's royalty gas may be required for use within the State. However, the major source of gas for future use within the State will be available from new reserves found and transported through the system now considered for Prudhoe Bay. We are confident this new gas will become available as the natural gas demand grows in Alaska.

Tenneco would consider a reservation by the State of up to 10% of the royalty gas production for use within Alaska so long as the pipeline, plant and shipping design would accommodate it. The State would own this gas and pay the applicable transportation tariff. In the event this gas was not used within the State, it would be sold to Tenneco under the contemplated contract.

4. Pricing

The gas produced at Prudhoe Bay will flow into interstate commerce and under current regulations would be subjected to control by the U. S. Federal Power Commission. Tennessee Gas is also a company regulated by the FPC. For this reason, we are unable to guarantee a specific wellhead price.

We feel the best assurance for maximum possible price lay in the requirements and market potential of the purchaser. Tenneco's interstate pipeline systems have average current requirements for supplying existing customers of 3.8 Bcf per day making us one of the largest interstate systems in the U. S. The majority of our current market consists of the higher premium residential and commercial market.

We can contract to pay the maximum price permitted by the FPC and are willing to do so. Our market analysis indicates that the wellhead price will be at least \$.50/Mcf in the early 1980's, and that it will increase on an annual basis as the project matures. In addition, we do not expect that deregulation, in whatever form it could be established, would have the effect of reducing the wellhead price below this figure.

We propose that Tenneco (through Tennessee Gas Transmission Company or a subsidiary) and the State immediately enter into negotiations for the purpose of purchasing the right to contract the State royalty gas in Prudhoe Bay and securing support for a trans-Alaska market outlet.

SUMMARY

I represent Tennessee Gas Transmission, the natural gas pipeline subsidiary of Tenneco Inc. By letter dated May 22, 1975, the Commissioner of Natural Resources of the State of Alaska requested Tennessee Gas Transmission to submit a proposal for the disposition of the State's royalty gas in the Prudhoe Bay Field. Our memorandum dated August 28, 1975, was in response to this request.

The suggested approach discussed in the memorandum resulted from our assessment of critical factors to be considered by both the State and our company. The approach outlined is acceptable to our company and we have submitted it for review by this Board.

The main thrust of the approach we suggest is contained in the overall benefits to be obtained by each party. The significant benefits we feel should accrue to the State compared to what we have suggested in our memorandum are as follows:

Benefit 1: The company acquiring the right to contract the royalty reserves should be capable of giving maximum support to obtaining a trans-Alaska pipeline route.

Approach: As of this date, Tenneco has not actively supported a project designed to market North Slope gas. With the securing of the right to contract the State royalty gas we would be prepared to give maximum support to the securing of a trans-Alaskan route. This support would be in the form of time, money and people. This support would be fully coordinated with the State to insure maximum impact.

Benefit 2: The State should receive substantial front-end money.

Approach: Tenneco will make available to the State an amount in excess of \$100 million for the right to contract all of the royalty natural gas reserves in the Prudhoe Bay field. The exact amount contributed will be subject to negotiations between the parties and will reflect the needs of the State, the drawdown schedule and other factors. These funds will be made available to the State over a three-year period according to a mutually acceptable schedule. There will be no recovery of the contributed funds for a period of three years following the date of the advance. The contributions will be recovered out of a percentage of the royalty gas or oil production beginning three years after the drawdown and continuing over a recovery period of five years. These funds made available to the State would be interest free.

Benefit 3: Some of the gas must be available for use in Alaska.

Approach: Tenneco would consider a reservation by the State for up to 10% of the royalty gas production for use within Alaska.

We do not intend to imply that this 10% represents the maximum anticipated future growth of the State's natural gas needs. We feel the primary goal at this time is to insure a Trans-Alaskan system. The major source of gas for long-term growth will be available from future reserves found and transported through this system.

Benefit 4: The maximum possible wellhead price should be paid at the wellhead for the reserves when produced.

Approach: The gas produced at Prudhoe Bay will flow into interstate commerce and under current regulations would be subjected to control by the U.S. Federal Power Commission. Tennessee Gas is also a company regulated by the FPC. For this reason, we are unable to guarantee a specific wellhead price.

We feel the best assurance for maximum possible pricing lay in the requirements and market potential of the purchaser. Tenneco's interstate pipeline systems have average current requirements for supplying existing customers of 3.8 Bcf per day making us one of the largest interstate systems in the U.S. The majority of our current market consists of the higher premium residential and commercial market.

We can contract to pay the maximum price permitted by the FPC and are willing to do so. Our market analysis indicates that the wellhead price will be at least \$.50/Mcf in the early 1980's, and that it will increase on an annual basis as the project matures.

These are the major benefits accruing to the State of which the most important is the support of the pipeline route across Alaska.

The purchaser is subject to unknown timing factors and substantial risks associated with purchasing the right to contract Prudhoe Bay gas. To compensate for these risks, certain benefits must accrue to the purchaser. These are as follows:

- a. The front-end payment must be financeable eliminating the necessity for the company to make a large capital advance in a single year.
- b. The front-end payment must be recoverable at a particular point in time. We have structured an eight-year recovery period in this approach. This recovery will be from a percentage of royalty natural gas or oil revenue.
- c. The right to contract all of the State's royalty gas in Prudhoe Bay would be secured subject only to the 10% reservation by the State for use within Alaska.

We feel the most important consideration by the State at this time is the securing of a Trans-Alaska routing for the Prudhoe Bay reserves. This is the one single factor that will have the greatest impact on the State throughout its future. This must be considered in relation to the other benefits which can be obtained either through the proposal we submitted or the approach recommended by any other company.

- a. Front-end Capital Contribution - Strictly a short-term benefit and will be available regardless of the route selected.

- b. Wellhead Price - You will be assured of getting the maximum permissible price regardless of the pipeline routing.
- c. Retention of Gas for Use in Alaska - This has little if any value if the market outlet does not cross Alaska.
- d. Routing - This is a mutually exclusive, either-or decision. The market outlet will either cross Alaska or it will not. Once a route is selected, it will influence exploration because companies understand that reserves from future discoveries in the North will be transported to market through the first system constructed or by an expansion of that system. Resulting economic and industrial benefits will accrue to that system and to industry and people able to be served by it.
- e. To insure there is no question about our intentions to support the routing of this project, we are willing to give the State the option to terminate our right to contract should the trans-Alaska route not be approved. This termination would be conditioned only upon the State refunding our capital contributions plus interest and assuring us we would not be prejudiced in any future attempts to contract the royalty gas.

We understand the difficulties you face in deciding in the near term a question as important as how to dispose of the State's royalty gas. We have heard arguments that the State's interest can be best served by leaving the gas in the ground as bargaining leverage to assure that gas is available in the State for future development and expansion and to assure that what gas is sold returns the highest possible price.

However, we do not think it feasible to keep part of the gas in the ground. Either the gas will flow to market or it won't; it's all or nothing. Another factor which must be considered is the natural gas shortage in the lower 48. Headlines yesterday in the Seattle newspaper said "500,000 Americans jobless this winter due to natural gas shortage." Future prospects are not encouraging.

This State's policies have always responded to such overriding national interests and we not believe the State will now alter that basic approach.

Moreover, as this Board is well aware, a decision now to agree to contract the royalty gas does not commit the State to a specific price. As mentioned, we will agree to pay the maximum permissible price.

We are not aware of all the proposals that have been presented to the State for the contracting of their royalty natural gas reserves. I'm sure there have been many. I'm confident, however, that no other company can offer the State the additional support for a trans-Alaska route that our approach insures. It is in this additional support that our proposal will differ from any other proposal which the State receives.

We see the contracting of royalty gas as leverage supporting the routing of the pipeline across Alaska. This leverage is very strong now but will weaken rapidly with time and will disappear completely if not used. In our opinion critical decisions concerning the routing will be made in the next 6 - 12 months.

We have recommended to you that a negotiated sale of the right to contract the royalty natural gas is the most advantageous method. We recognize the political problems inherent in a government entity negotiating a sale, but the objectives we envision cannot be achieved through a competitive bid sale. As an example, how many bidders could supply the same degree of effectiveness in providing additional support for the trans-Alaska route?

My company is prepared to enter into negotiations with the State or this Board for the purpose of securing the right to contract the State's royalty gas in Prudhoe Bay and to provide support for a trans-Alaska pipeline route.

Tennessee Gas Transmission
A Tenneco Company



Robert C. Thomas
Vice President

Chamber of Commerce Building
P. O. Box 2511
Houston, Texas 77001
(713) 229-2275

November 3, 1975

Mr. Guy R. Martin
Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99801

Dear Mr. Martin:

In accordance with your request, we have prepared a comparison of the offers submitted to the State of Alaska by Tennessee Gas Transmission Company and El Paso Natural Gas Company for the purchase of royalty gas from Prudhoe Bay Field. The comparison is summarized on the attached tabulation.

In our opinion, the primary consideration to be given by the State is the securing of the pipeline route across Alaska. The most significant difference between the two offers is Tenneco's ability and commitment to give additional support to this route selection. To insure there is no question concerning this support, Tenneco has agreed to allow the State to terminate the right to purchase the gas should the pipeline route not cross Alaska.

We will look forward to working with the State in the furthering of this project.

Robert C. Thomas

cm

Attachment

bcc: Jared Carter w/attachment

COMPARISON OF OFFERS SUBMITTED TO THE
STATE OF ALASKA BY TENNECO AND EL PASO
FOR THE PURCHASE OF PRUDHOE BAY ROYALTY GAS

	<u>TENNECO</u>	<u>EL PASO</u>
1. Gas Volume	All royalty gas but State can reserve up to 10% for their needs.	All royalty gas or any part surplus to State's needs.
2. Advance Payment	In excess of \$100 million subject to negotiation.	10¢/MCF of gas dedicated which equates to \$300 million for all of the royalty gas.
3. Conditions precedent for making advance payment	None	Requisite governmental authorizations in satisfactory form and the conclusion of all necessary financial arrangements (rate base treatment of the advance).
4. Recovery of advance payment	In 5 years starting 3 years after drawdown or a total of 8 years.	Within 7 years of commencement of oil or gas production or 7 years after date of advance, whichever is later.
5. Offer to pay share of field gathering and processing facilities if assessed to State of Alaska by producers in order to take in kind	No	Yes
NOTE: Government is not normally required to invest in field facilities to take in kind, but to pay a fee for gathering and processing royalty gas. Lease agreements provide for government taking delivery in kind at a mutually agreed upon point and for the producer to charge a fee for any processing.		
6. Give additional support to the Alaskan pipeline route	Yes	No
7. Interest charged on advance payment to the State	No	No
8. Relinquish right to purchase gas if pipeline goes across Canada	Yes	No

HISTORICAL NET PRODUCTION OF NATURAL GAS IN TEXAS
(BILLIONS OF CUBIC FEET)
1962-1973

	<u>Intrastate</u>	<u>Interstate</u>	<u>Total</u>
1962	3250	2960	6210
1963	3359	2979	6338
1964	3442	3165	6607
1965	3538	3201	6739
1966	3787	3276	7063
1967	3984	3334	7318
1968	4159	3461	7620
1969	4345	3620	7965
1970	4614	3844	8458
1971	4900	3721	8621
1972	4930	3788	8718
1973	5123	3427	8550

FINANCIAL STATISTICS - MAJOR GAS TRANSMISSION COMPANIES

\$ - Millions

	<u>12-31-74 Assets</u>	<u>Gross Revenue 1974</u>	<u>Net Income 1974</u>
Arkansas Louisiana Gas Company	\$ 616	\$ 280	\$ 59
Cities Service Gas Company	2,898	2,806	204
*Colorado Interstate Gas Company	454	354	38
*Columbia Gas Transmission Corporation	2,838	1,278	110
Consolidated Natural Gas Company	1,636	861	63
El Paso Natural Gas Company	2,122	1,251	74
Florida Gas Transmission Company	273	104	13
*Michigan-Wisconsin Pipe Line Company	1,161	531	50
Mississippi River Transmission Corp.	176	142	12
*Natural Gas Pipeline Company of America	1,269	564	99
*Northern Natural Gas Company	1,704	1,013	120
Northwest Pipeline Corporation	406	276	15
*Panhandle Eastern Pipeline Company	951	564	69
Southern Natural Gas Company	1,066	539	59
Tennessee Gas Pipeline Company	6,402	5,001	321
*Texas Eastern Gas Transmission Corp.	2,438	1,065	192
Texas Gas Transmission Corporation	864	692	45
Transcontinental Pipe Line Corp.	1,532	520	12
United Gas Pipe Line Company	565	608	20

*Participants in Gas Arctic

Tennessee Gas Transmission
A Tenneco Company



Robert C. Thomas
Vice President

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P. O. Box 2511
Houston, Texas 77001
(713) 229-2275

October 31, 1975

Mr. Guy Martin, Commissioner
Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99801

Dear Mr. Martin:

During my presentation to the Alaskan Royalty Oil and Gas Advisory Board earlier this month, it was requested that we provide additional information concerning the effect of FPC regulation on the ability of the State to utilize a portion of their royalty gas within the State. The attached memorandum is submitted in response to that request. It is still our belief that the State is free from the direct jurisdiction of the FPC, but the FPC will be able to exercise some indirect control. Freedom from this indirect control could be obtained by securing the proper authorizations in the initial certificate or by securing appropriate federal legislation. Either of these alternatives are considered feasible if the proper actions are taken by the State in the very near future.

There are some that support a state-owned pipeline to insure freedom from FPC jurisdiction. Our memorandum mentions this point. In legal theory this may have merit, but in reality there is little basis for support for at least two reasons:

1. A pipeline from the North Slope is tremendously expensive regardless of its planned capacity. Based upon current events, investor confidence in municipal and State financings may not be sufficient to support such a venture.
2. If financing were available, the State would be obligating itself for all of the capital required for the pipeline in order to secure assurance of access to their royalty gas which is no more than 12 1/2% of the gas transported.

The benefits do not appear to justify the risk involved in the State's financing of a pipeline. Future decontrol of natural gas could eliminate the indirect control by the FPC without the necessity of the financial involvement.

Tennessee Gas Transmission

Mr. Guy Martin, Commissioner

-2-

October 31, 1975

We trust this information will be of benefit to you and the Board. Our legal representatives would be prepared to discuss this problem in greater detail with your legal counsel if you consider it worthwhile.

Robert C. Thomas

cm

Attachments

bcc: Jared Carter w/o attachments

The following is written in an effort to summarize recent discussions concerning the relationship of regulation by the Federal Power Commission (FPC) and the sale by the State of Alaska of its royalty interest in Prudhoe Bay gas.

I

It is conceivable under an appropriate fact situation that the FPC would have no jurisdiction over the production, sale and use of any Prudhoe Bay gas. This situation would exist if all the gas were produced within the State of Alaska (none from offshore Federal leases) and all gas were consumed in Alaska without ever having left Alaska. In this fact situation the State of Alaska and all producer sellers could sell gas and be subject only to those restrictions contained within their sales contracts. However, because of the lack of market and the cost of facilities needed to get the gas from Prudhoe Bay to whatever Alaskan market there is, such a totally intrastate project is not presently feasible.

II

Proceeding then on the assumption that most of the gas produced from Prudhoe Bay will necessarily leave Alaska and must in some manner be transported to and consumed in the lower 48 states, it must be recognized that any such project cannot become a reality without FPC approval of some particular facet of its operation. It must also be recognized that the necessity of FPC approval for portions of such project, coupled with the FPC's right to consider all factors bearing on the public interest and convenience, gives the FPC a position in determining what type of project is ultimately built. This does not, however, mean that the State of Alaska cannot endeavor to structure a project that gives the State of Alaska the best opportunity possible to utilize its royalty gas as Alaska sees fit.

The FPC generally has jurisdiction over the sale for resale of natural gas in interstate commerce, the transportation of gas in interstate commerce, and the construction and operation of facilities to be used for such sales and transportation. However, it appears that (1) the FPC would have no direct certificate jurisdiction over the sale of royalty gas by the State of Alaska and (2) that the FPC would have no jurisdiction to fix the rates at which Alaska could sell its royalty gas whether by direct sale or by sale in interstate commerce for resale. Such conclusion is reached on the basis that Alaska is neither a "person" nor a "natural gas company" within the meaning of the Natural Gas Act. The FPC's regulatory authority covers only those entities which are "persons" or "natural gas companies" as defined in Section 2 of the Act.

Section 2 of the Act defines "natural gas company" to mean a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale. That same section defines "person" to include an individual or a corporation. A corporation is defined to exclude municipalities. "Municipality" is defined as a city, county, or other political subdivision of a State. Inasmuch as the State of Alaska would probably sell the royalty gas through some agency of the State, the FPC would have no direct jurisdiction over such transaction.

There is authority to support the conclusion that the State of Alaska is beyond the jurisdiction of the FPC. In *Tennessee Gas Pipeline Company, Docket Nos. CP66-269, et al.*, by order issued June 29, 1967 (37 FPC 1195) the FPC made the following statement concerning the State of Louisiana as a royalty owner (37 FPC 1197):

"We note that in addition to the aforementioned, the State of Louisiana and one of its local subdivisions (the Buras Levee District) are among the royalty owners of the acreage at issue. But Section 2(5) of the Natural Gas Act would seem to exclude such political entities from the definition of "natural-gas company" and thus exempt them from the necessity of obtaining this Commission's authorization prior to effectuating an interstate sale. However, in view of the fact that this Commission already has made clear its concern with the cost to Tennessee of the Bastian Bay reserves we would expect that both the State of Louisiana and the Buras Levee District will be most interested in the course of these proceedings and we would welcome their participation as interveners."

Since the State of Alaska is not a "natural gas company" under the Natural Gas Act, the FPC would also be precluded from regulating other activities performed by the State of Alaska which, if done by some other entity, would be subject to FPC regulation. Therefore, if the State of Alaska were to construct and operate a natural gas pipeline from Prudhoe Bay to the southern coast of Alaska, the construction and operation of that pipeline and the transportation of gas by that pipeline would not be subject to direct FPC regulation, even though all or some portion of the gas ultimately entered the interstate market. Under this arrangement, all of the gas produced in Prudhoe Bay could be transported to the southern end of the pipeline with no direct certificate regulation by the FPC and the rates to be charged by such pipeline for transporting gas from Prudhoe Bay to the terminus would not be subject to direct FPC regulation.

While sales of Alaska's royalty gas made from such line would not be subject to direct FPC control, the sale of gas attributable to the working interests of Prudhoe Bay leases would, of course, be subject to FPC regulation, whether made at the wellhead or at the southern terminal of the line, if such sales were made to a "natural gas company". The resale in interstate commerce of Alaskan royalty gas, facilities necessary at the terminus of the line for the liquefaction of the gas and loading of LNG, the facilities necessary to receive and transport such gas, and the resale of such gas in the United States would be subject to direct regulation by the FPC. Through its regulation of these aspects the FPC might affect the viability of any contractual arrangements made for Alaska's royalty gas.

III

In view of the existing provisions of the Natural Gas Act, the State of Alaska is exempt from direct FPC regulation. However, under certain

circumstances, it will be subject to indirect regulation. If we assume that the pipeline from Prudhoe Bay to the southern coast of Alaska will be constructed and operated by a "natural gas company", the State of Alaska will be subject to indirect regulation if any part of its royalty gas enters such a pipeline.

To the extent royalty gas is so transported, even if transported only within Alaska and consumed in Alaska, the transporting pipeline will be required to obtain a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act. The rate charged by the jurisdictional pipeline for such transportation will be subject to FPC regulation under Section 4 of the Act. This is the situation that must be anticipated under either the present Gas Arctic route or the present Trans-Alaska route. While Alaska might sell its royalty gas at an unregulated price, the FPC will have direct control over the transportation rates charged by jurisdictional pipelines that carry the gas to the ultimate market. In addition, to the extent any buyer of Alaska's royalty gas resells such gas in interstate commerce, that rate will be subject to FPC regulation. Thus, through its regulation of the rates allowed for resale or the rates allowed for transportation, the FPC might affect the viability of any contractual arrangements made for Alaska's royalty gas.

The Commission, in exercising its authority to regulate the transportation of gas by interstate pipelines, has refused to grant such authorization due, in part, to the inferior end use for which the transported gas was destined. See F.P.C. v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1, (1961) and Arizona Public Service Company v. F.P.C., 483 F.2d 1275 (1973). In those two cases certificates were denied, and the Courts upheld such denial, because, among other things, the consumer intended to use the gas for boiler fuel -- an inferior use. Thus, in processing an application for authorization to transport gas in interstate commerce, the Commission will consider the end use of the gas. It might be possible for a pipeline to distinguish the Transco and APS cases and to show that the present and future public convenience and necessity requires certification of a particular transportation agreement.

IV

As indicated above, it appears that the FPC, under the Natural Gas Act, has no direct jurisdiction over Alaskan royalty gas committed to the Alaska pipeline project. The State of Alaska would, therefore, be free to sell all or part of its royalty gas at whatever price it can negotiate and to withdraw such gas from the course of such sales in accordance with the terms of its sales contracts without governance by the FPC.

Despite the latitude afforded an entity exempt from FPC regulation, there is a degree of indirect regulation due the jurisdiction of the FPC over the natural gas company operating the pipeline across Alaska. Such indirect regulation would arise each time the State of Alaska effected a change which required the natural gas company to amend its certificate.

Thus, at the time the State of Alaska desired to enforce that contractual provision permitting a portion of the royalty gas to be used within the State, the natural gas company would have to obtain a certificate authorizing such modification in service. However, it would appear that, in view of the State's exempt status, the holding of Granite Cities Steel Company v. Federal Power Commission, 320 F.2d 711 (D.C. Cir. 1963) would have no bearing on the State of Alaska's authority to divert a portion of its royalty gas to users within the State.

V

In order to completely circumvent the indirect regulation of Alaska adverted to above, it is conceivable that the legislative branch of the U.S. Government could propose legislation that the executive would sign which specifically (a) removed the issue of the transportation of Alaskan gas to the lower 48 states from the jurisdiction of the FPC and (b) provide procedural guidelines for the resolution of all legal issues associated with such transportation. Under such a statute, it is probable that the Natural Gas Act would be suspended as it applied to the Alaskan gas, thus mooted all of the legal principles enunciated herein. In view of the various approaches such legislation could take, a detailed discussion at this time would constitute mere speculation.

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

Memo: To Committee members
From: Eric
Re: ISEGR briefing
11/19

The meeting was open to all legislators and staff.
Attending;

John Huber	Ted Smith
Joe Orsini	Susan Sullivan
Ed Willis	Kathryn Ostrosky
Jim Rhodes	Bill McGuire
Anne Carbonetti--Leg. Affairs	
Mike Scott	ISEGR
Dave Kresge	ISEGR
Eric Eckholm	

The briefing dealt with the ISEGR study prepared for Dept. of Interior. Enclosed is a recent study they prepared, the last portion is a summary of the ISEGR report. Also, I mailed out a very brief summary prior to the meeting.

The map details 10 proposed routes that ISEGR is running through their "Man in the Arctic" computer model for the BLM. They should have results on economic impact by early January.

They reiterated their main points from the study;

1) per capita income does not rise more than 2% from either proposal, due to population migration.

2) They assume the state is going to save 50% of their petroleum revenue in an investment fund. This will mitigate the "boom/bust" cycle by providing long term state revenue not tied to the initial resource. (see report inclosed)
This investment fund is assumed to provide a 7% return on investment.

Other comments

- 1) If El Paso goes, there will be a significant detrimental effect on pricing of goods in Alaska. It follows on the heels of the oil line, and another boom will probably cycle inflationary pricing higher than normal inflationary process'.
- 2) Petrochemical Industry is high capital-intensive. In other words, it does not provide much employment, and the revenue generated will be minor compared to the North Slope tax base. Kresge suggested a tax break for industry producing in-state consumable items such as cement/food processing.
- 3) little can be done about boom/bust economics, but by state saving revenue, the end can be tapered off the "bust" stage.
- 4) If "Project Independence" suggestions are followed, Alaska will have a well everywhere there is the smell of oil or gas. Kresge feels this is not feasible, but they do assume OCS development in creating their state growth model.

Memo: Members of the Gas Pipeline Impact Committee
From: Eric Eckholm
Re: Cook Inlet Royalty Gas
11/25/75

Problem: Anchorage Natural Gas (ANG) has asked for the right to purchase the state royalty gas from the North Cook Inlet field. This gas is presently being sold to Phillip's Petroleum for use in their Liquefied Natural Gas (LNG) operation, which is then shipped to Japan. The Royalty Board, with the concurrence of the legislature determines use of royalty gas.

ANG's Proposal:

1) ANG wants to purchase all of the state's royalty gas now being purchased by Phillips, at a price equal to that being paid to Phillips.

--This could be done as a "paper trade" in that gas from the North Cook Inlet is equal to gas from Swanson River areas where ANG is currently receiving gas. ANG could purchase royalty gas in equivalent amounts from Swanson River, and credit the North Cook Inlet producer.

2) ANG says their reserves are running low, and purchase of State royalty gas will allow them to continue to fill their contracts with state users that might have to be switched to costlier oil fuel (i.e. Bernice Lake power plant) if gas was not available. This would increase electrical costs to consumers.

Also, the amount of gas available to ANG is limited (550 Billion Cubic Feet until 1992), and they are seeking to build up their reserves to assure continued financing.

Phillip's response:

1) ANG doesn't really need the gas. They are building a case without real needs because they want cheap gas in the future. At present, ANG is only utilizing 72 Million Cubic Feet/day when their contract allows as much as 160 MMcf/day.

2) Phillips has created a market for LNG that didn't exist, at considerable risk and expense to Phillips. They sunk \$125 million developing the market, and their partners pulled out, leaving Phillips with all the risk. They generated income for the state that would not have been there without Phillips. By taking the state royalty gas, the economics of Phillips operation would be impacted.

3) There is a possibility of allowing Phillips to come under APUC regulation if the gas is sold to ANG. Phillips does not want to become regulated as a public utility, and the small percent of royalty gas should not warrant them being regulated by the APUC.

11/25/75

Page 2, Royalty proposal

Staff comment:

This proposal could be an important precedent for future use of the State's royalty gas.

--It signals the intention of the state to use gas "in-kind" and within the state, if possible. Previously, royalty gas was assumed to be paid on a 1/8th of revenue basis, not as possible real gas for state use. All of the projections by industry of gas development include the royalty gas, with the assumption that the state would take 1/8th share of \$\$, not gas. This is true with North Slope transportation system plans.

Staff recommendation:

Sell the gas to ANG, with the following conditions;

--ANG demonstrates a real need for the gas.

--ANG pays a price equivalent to that being paid by Phillips, and it continues to rise on a equitable market price.

(The state would not be "subsidizing" Anchorage users)

--Phillip's Petroleum is not subject to critical economic burden.

(Phillips has wells drilled on their present platform that are not being used. They have a contract with the Japanese for 15 years--1970-1985, 140 MMcf/day delivered to Japan. They would have to confirm their reserves and ability to meet their contract.) This would also probably increase development of the Cook Inlet field.

[Staff note--I toured the Phillip's plant in Kenai. I was impressed by the efficiency of the operations, and the environmental concern. Phillip's also had an Alaskan hire policy, 10 out of 46 employees were Alaskan natives, and they trained employees in all phases of the operation. They are a highly capital-intensive industry that appear to me to be a positive asset in terms of natural gas resource use in Alaska. Although I recommend taking the royalty gas, I believe that the state should be concerned in maintaining a good business relationship with Phillips.]

The Royalty Board is meeting December 9 and 10. They will be giving a presentation to this Committee on December 11. If they take action relative to the royalty gas, the legislature would be asked for a concurrent resolution during the session.

Phillips has not signed a contract with the state, they pay the state essentially on a day to day basis. By selling the gas to ANG, we would not be cancelling any contracts.

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



Alaska State Legislature
JOINT GAS PIPELINE IMPACT COMMITTEE

November 17, 1975

QUESTIONS CONCERNING
THE PRUDHOE BAY NATURAL GAS RESERVOIR
AND RELATED MATERIALS

In the following questions, "Aerospace" refers to the two volume draft study entitled Alaska Natural Gas Transportation Systems, prepared by the Aerospace Corporation under contract to the Department of the Interior, and published by the latter in June, 1975. Unhyphenated page numbers (i.e., Aerospace, p. 19) refer to Volume I, containing the executive summary. Hyphenated page references (Aerospace, p. 3-13) refer to the backup material contained in Volume II. "Gruy" refers to the two volume analysis prepared by H. J. Gruy and Associates, Inc., of Dallas, Texas under subcontract to the Aerospace Corporation. The analysis is entitled Gas Supply Study, Alaska Natural Gas Transportation System, Sadlerochit Reservoir, Pruhoe Bay Field, Alaska. Copies of selected pages from these studies are attached. However, all four volumes are available for review and copying in the committee's Anchorage office.

1. (A) What discount rate does your firm use in evaluating field development investment of the sort envisaged in the Prudhoe Bay area?

(B) If more than one rate is used, indicate the reasons, and the circumstances appropriate to each rate.
2. (A) Are there any circumstance under which a requirement to reinject all gas produced could lead to a reduction in the rate of oil recovery, or in the ultimate recovery?

(B) If so, explain those conditions and estimate the amount of reduction.

(C) Are there any circumstances under which the reinjection of gas could be more costly than production of gas for sale?

3. (A) The Aerospace study states (p. 3-30) that gas compression for reinjection will require five percent of the gas as fuel. Is this a reasonable estimate?
- (B) How does this compare with the field consumption of gas to be expected under the assumption of maximum production for sale?
- (C) Neglecting the gas used as compression fuel, is there any reason why all the re-injected gas could not eventually be recovered?
- (D) Assuming that all gas was reinjected, at what point do you estimate the total quantity of gas reinjected would equal the total recoverable gas reserves contained in the reservoir?
- (E) Would this quantity (less that consumed in reinjection) actually be recoverable at that point? If more or less, why?
4. (A) Are the cost figures used in the H. J. Gruy model (Aerospace, p. 3-23 and Gruy, p. 10) reasonable?
- (B) Aerospace (p. 3-22) indicates that the quantity dependent costs are in addition to the costs of water treatment plants, but no cost figures are provided for such plants. Apparently, there are similar additional capital costs associated with gas processing, to control the water and hydrocarbon dewpoints, and to remove carbon dioxide (Aerospace Report, p. 3-8). Please explain the relative costs of these activities, and any other related activity necessary to prepare the gas for sale, so that the committee can have a general idea of why the costs of producing the gas for sale are higher than the costs of production for reinjection.

5. (A) Have you entered into any agreements for the sale of your share of the Prudhoe Bay gas which would require you to produce the gas even if the price obtainable for it was very low?
(B) What minimum price, if any, is mentioned in any gas sale or option agreement covering North Slope gas to which your firm is a party?
6. (A) What will become of the heavier hydrocarbons contained in the gas stream (ethane and heavier) if the gas is reinjected?
(B) If it is sold?
(C) To what extent, if any, has your firm committed itself to the sale of these heavier hydrocarbons?
7. (A) Will the proceeds of the production of gas and oil be shared by the producers on the basis of original oil and gas in place?
(B) If not, then how?
(C) If, as is indicated in Gruy, the production of gas for sale results in a loss of oil, what principal will govern the apportionment of this loss among the field's several owners?
8. (A) The Aerospace study indicates that the future field development costs of gas production for sale exceed the costs of field development under a 100% reinjection assumption by a substantial amount. (Aerospace, p. 19 indicates a difference of \$3.8 billion). Does your firm generally believe this to be a realistic prediction?
(B) If so, please explain the reasons for this \$3.8 billion difference; if not, why?

9. (A) Pages 3-37 of the Aerospace report indicate that the total costs of producing the gas, considering the lost oil production (at \$9/barrel) and the actual field development costs, under maximum pressure maintenance, would be \$7.251 billion. Is this a reasonable figure? If not, what would be a reasonable estimate?
- (B) The Aerospace report indicates that, assuming a \$9/barrel price for oil and a 10% discount rate, the cost of gas production will be \$47/MCF (Aerospace, p. 3-38, 3-39). Is this a reasonable figure? If not, what would be a reasonable figure?
10. (A) Would your firm be willing to develop the field for gas production (for sale) if the expected revenue from the gas sales were less than the costs of its production? (In other words, are there any circumstances under which your firm would go ahead with development for gas sales even if the present net worth of the field (or your part of it) were to be reduced thereby?)
- (B) Are there any circumstances under which the production of natural gas could be subsidized by the production of oil?
- (C) Are there circumstances under which a firm could be compelled to produce the gas even though such production did not make economic sense?
11. (A) The Aerospace study seems to indicate that the maximum gas production from the Prudhoe Bay Reservoir sustainable for any substantial period of time, without undue loss or oil recovery, is about 2.5 BCF/day. Some pipeline feasibility calculations

seem to be predicated on a higher rate of production. Is the Aerospace estimate realistic?

(B) If not, what is a realistic estimate?

SIGNIFICANT FINDINGS

From the sensitivity indications it was clear that pressure maintenance with peripheral water injection yields higher discounted future net revenue (DFNR) values than those obtained from depletion cases. The pressure maintenance cases become more attractive as the prices for oil and gas increase. Oil production rates of 2.0 million bopd appeared difficult to maintain for many years as did gas deliveries above 2.5 bcfd. For the range of oil and gas prices considered, drilling at 160-acre spacing does yield maximum DFNR, but involves a large capital expenditure at a time when reservoir parameters are not very well defined. A prudent choice of 320-acre spacing for preliminary drilling spacing obtains a reasonable DFNR at a moderate risk on capital expenditure. Infill drilling to 160 or even 80-acre spacing could then be deferred until the reservoir is defined and the wells are needed. Gas-oil ratio limits were not critical although DFNR showed unexpected sensitivity to such limits as the gas price increased. Ratios above 15,000 cubic feet per barrel seem to penalize oil production without corresponding economic gains.

Five cases assuming some restrictions on the sale of gas and moderate to maximum usage of injected water for pressure maintenance emerged as being of greatest interest. They are the following:

Case 19 (42126) - This case tests the capability to sustain a 2.0 million barrel per day oil recovery rate, by pressure maintenance with water injection and by reinjection of 95 percent of the produced gas. The gas compression for reinjection requires five percent of the gas as fuel. The oil rate is held to 1.2 million barrels per day for the first four years of production, the gas-oil ratio limit is set at 4,000 cubic feet per barrel, and the minimum well spacing is 320 acres. The total oil produced through year 25 is 7.84 billion barrels with no gas sales.

Case 20 (22326) - This case considers partial pressure maintenance by water injection with the same oil production rate limits of 1.2 million barrels per day for four years increasing to 2.0 million barrels per day thereafter. Gas sales begin after the fourth year of production and are held to 2.5 billion cubic feet per day. With the production of gas cap gas and some increase in water injection, this rate is observed to hold for six years and then to commence a steady decrease. Well spacing and gas-oil ratio limit are the same as for the previous case. Oil production amounts to 6.75 billion barrels with gas sales of 14.448 trillion cubic feet.

Case 21 (22322) - This case modifies Case 20 to reach gas sales of 3.5 billion cubic feet per day and increase the gas-oil ratio limit to 10,500 cubic feet per barrel. Calculated oil production totals 6.26 billion barrels and gas sales are 15.320 trillion cubic feet.

Development and Operating Costs

SADLEROCHIT RESERVOIR

	<u>ESTIMATED COST</u>
DRILL AND COMPLETE TYPICAL WELL	\$3,000,000
FIRST WORKOVER	220,000
SECOND WORKOVER	310,000
ABANDONMENT	210,000
FIELD OPERATIONS, MONTHLY	\$9,020,000
QUANTITY-DEPENDENT COSTS	
PIPELINE GAS PROCESSING	\$0.07/MCF
GAS LIFT COMPRESSION	0.03/MCF
INJECTION GAS	0.05/MCF
INJECTION WATER	0.09/BBL
LIFTED OIL TREATMENT	0.023/BBL

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A two-dimensional three-phase simulator model was used for this study. The vertical equilibrium concept is incorporated in the two-dimensional model to simulate the flow behavior of an oil reservoir overlain by a gas cap and underlain by water.¹ The physics of the reservoir behavior is simulated by a set of differential equations that result from combining Darcy's law and the law of mass conservation for each phase in the system. The equations include the effects of gravity, viscosity, capillarity and fluid and rock compressibilities. The drive mechanism resulting from solution gas is also included in the differential equations. The differential equations are approximated by finite difference equations based on a Taylor's series expansion. The finite difference equations are simultaneously solved for each time increment for oil phase pressures and oil and water saturations by a modified version of the Strongly Implicit Procedure (SIP)². Fluid formation volume factors, solution gas-oil ratio and capillary pressure relationships are updated at each iteration by the Newton-Raphson method. Relative permeabilities and viscosities are explicitly calculated at the beginning of each time step. Calculation of relative permeabilities and capillary pressure relationships are based on the vertical equilibrium concept. A provision is provided to perform workovers on wells depending on assigned water-oil and gas-oil ratio limits.

B. Description of Economics Program (M-3)

The output from the D-2 Model provides data from which annual oil and gas production, gas and water injection, oil, gas or injection wells drilled, workovers performed and wells abandoned can be calculated.

The costs for all field operations are either supplied by card or have been incorporated in the economics program. The principal of these costs are listed on Table 4 for each case. The range of other costs considered but not shown on Table 4 are:

	<u>Minimum Cases 1-21</u>	<u>Maximum Cases 19-23</u>
Well drilling costs (includes contingency for dry holes)	\$1,650,000	\$3,000,000
First workover cost	75,000	220,000
Second workover cost	100,000	310,000
Well abandonment cost	75,000	210,000

PRUDHOE BAY COST DATA

Cost data were developed from published information, contacts with industry sources and subsequent discussions with Prudhoe Bay Field operators. Field development expenditures for facilities completed prior to January 1, 1975 have been included in the category of sunk costs, a lump sum figure estimated to be approximately \$1.2 billion. All costs are based on 1975 prices with no consideration for inflation.

The economics program applies these costs to the output of the D-2 Model which itemizes field activity, such as, the annual volumes of oil and gas produced; of oil produced by means of gas lift; of gas and water injected into the reservoir for pressure maintenance, etc. The monthly costs for field operations are incremented by the costs for drilling and completion of additional wells required for production or injection. Finally, wells are worked over accordingly to a set of prespecified rules, such as the following set for the occurrence of a gas-oil ratio above the limit specified for the simulation.

1. First workover, perforations are moved down one-half of original perforation interval and total perforated interval remains the same.
2. Second workover, perforations are reduced to the lower one-half of the previous thickness.
3. The third time the gas-oil ratio is exceeded, the well is abandoned.

The quantity-dependent costs are in addition to the capital expenditures provided for associated facilities, e.g., the injected water cost per barrel is added to the cost of water treatment plans and water injection wells.

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GAS PRODUCTION AND SALE

With the further development of the field made possible by completion of the Alyeska oil pipeline, oil and associated gas will be produced. While facilities will exist to reinject this gas for pressure maintenance, it is expected that substantial quantities of gas will be available for sale.

In this schematic, a typical production site is shown in relation to the subsurface reservoir in the Sadlerochit Formation. For illustrative purposes, the three wells are, from left to right, a gas injection well, a gas producer (reversible for injection), and an oil well. All have been drilled directionally from a common pad or drill site which will eventually accommodate 6 to 20 wells.

Production from three or four such sites will be processed at flow stations where the initial separation of gas, oil, and water occurs. The gas gathering system collects all of the produced gas at a central processing facility for further treatment to remove condensable liquids and for two-stage recompression to required injection pressures.

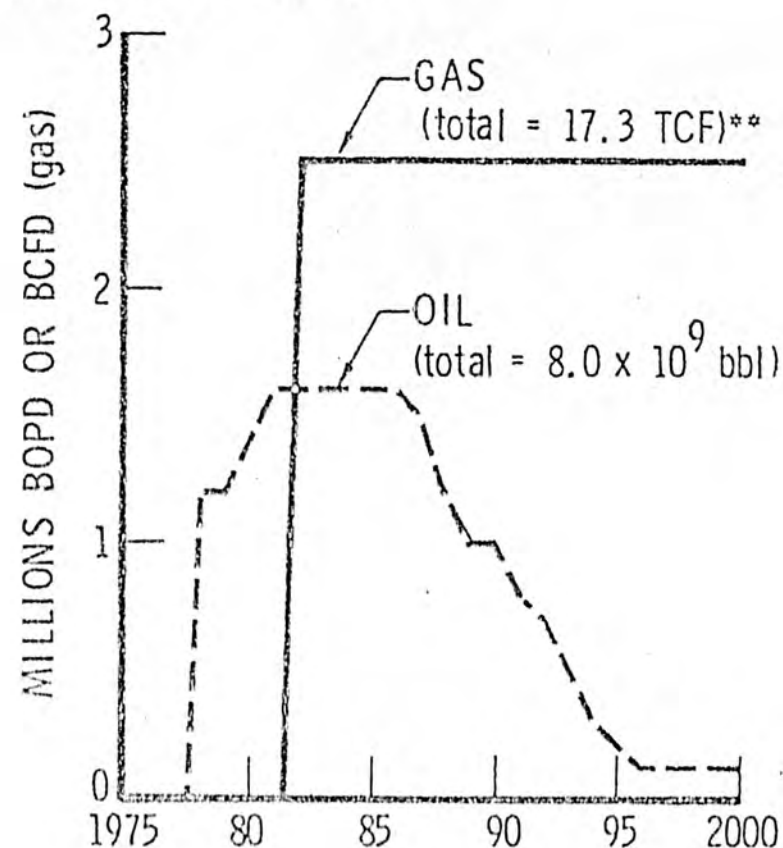
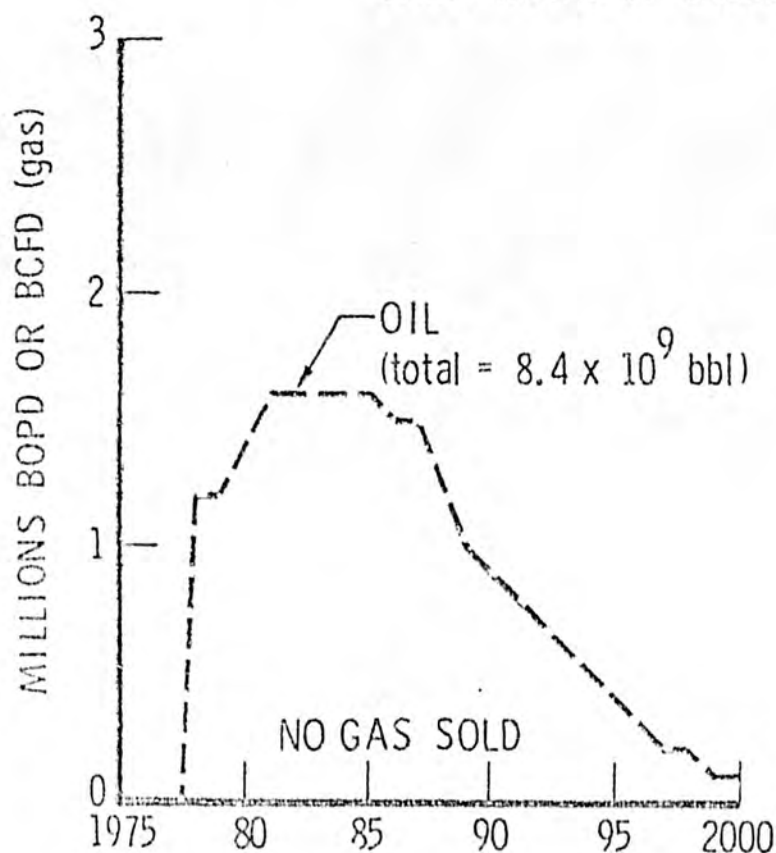
Gas not required for reinjection or other use will be processed for carbon dioxide removal and control of the water and hydrocarbon dew points before being routed through the first stage compressors for delivery to the pipeline point of sale.

Reservoir pressure, depleted by the withdrawal of oil and gas, can be maintained by the injection of water separated from the production stream at the flow station or obtained from other sources. Although the introduction of water increases the ultimate recovery of hydrocarbons, the collection, processing, and injection of water involves both plant and operating expenditures which add significantly to the field development costs.

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Prudhoe Bay Gas Supply

MAXIMUM PRESSURE MAINTENANCE IN SADLEROGHIT RESERVOIR
DAILY RATES OF SADLEROGHIT GAS AND OIL SALES



GAS SALES	NONE	2.5 BCFD
FIELD DEVELOPMENT COST*	\$8.2 billion	\$12.0 billion
COST PER MCF (Base Case)	--	\$ 0.47

* Estimated Future Expenditures Only

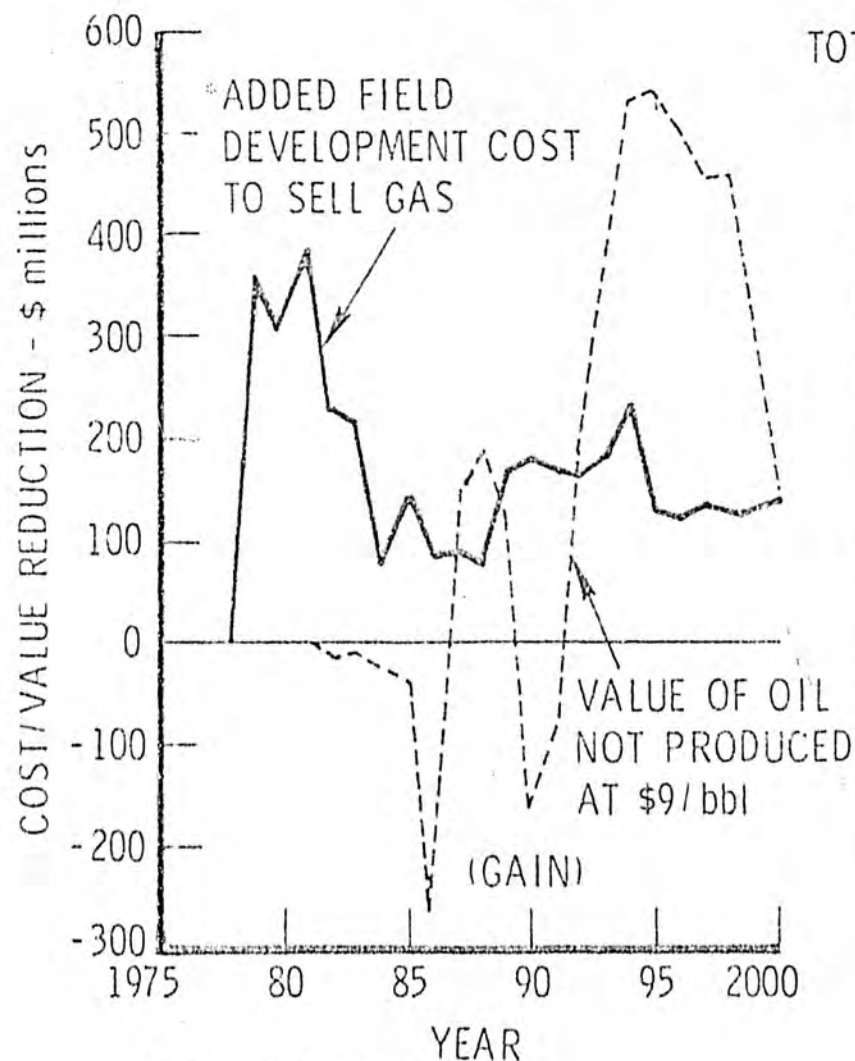
** 17.8 tcf Through Year 2000

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Resource Cost of Gas

MAXIMUM PRESSURE MAINTENANCE IN SADLEROGHIT RESERVOIR
2.5 BCFD GAS SALES vs NO GAS SOLD - 44402/44102



Estimated future expenditures only

TOTAL** RESOURCE COSTS TO SELL GAS - \$ millions

DISCOUNT RATE	OIL PRICE		
	\$5 / bbl	\$9 / bbl	\$12 / bbl
0%	5,727	7,251	8,394
5.0%	2,907	3,463	3,880
7.5%	2,183	2,523	2,778
10.0%	1,695	1,907	2,066
12.5%	1,349	1,477	1,573
15.0%	1,109	1,193	1,256
20.0%	785	817	841
25.0%	586	594	600

** Sum of field development cost to sell gas and gross value of oil not produced if gas is sold

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PRODUCERS COST OF GAS

As a practical measure of merit in comparing field development patterns, discounted future net revenue (DFNR) from the production and sale of both oil and gas has been calculated from the viewpoint of the field operators who must pay all production costs out of net (working interest) revenues after deducting production (state severance) taxes.

The fundamental concept described for establishing a resource cost of gas from any pair of field development options which are alike, except for the sale of gas, can also be used to arrive at an incremental unit cost to the operator for producing and selling the gas.

Regarded as a minimum wellhead price, it is that dollar amount per mcf of gas that would make the present discounted value of profits for the oil producing companies when no gas was produced just equal to the present discounted value of profits when gas was produced.

The generalized equation shown on the opposite page serves to calculate such an incremental average cost per mcf from the future field development costs and the forecast quantities of net oil and gas sold for the account of the working interests. The terms used are the same as those defined in the earlier explanation of Price-Discount Arrays. The discount rate and its relation to rate of return required by the producer of oil and gas to attract capital is discussed elsewhere in this report.

Using cost and net production figures from the comparative cases 44402 and 44102, previously discussed for maximum pressure maintenance in the Sadlerochit reservoir, and assuming a wellhead price of \$9 per barrel for oil, yields the curve at the right for a unit cost of selling gas which just equals the sum of added field cost, reduced oil revenues, and severance taxes. At 10%, the value is approximately \$0.47/mcf. For other prices of oil (P_o) at the same discount rate, the price of gas (P_g) needed to cover operators costs for this pair of cases is:

$$P_g(44102, 44402) = \$0.377 + 0.0108 P_o$$

The constant term (\$0.377) is the amount per mcf which can be attributed to the development and operating cost of selling the gas over reinjecting it and the determinant of the second term is literally the fraction of a barrel of oil which would not be sold for each mcf of gas which was sold. In these cases, an effort was made to minimize the effect of the variable term by planning the field development for like volumes of oil production when gas was produced as when it was not. The difference of 1% of a barrel per mcf is probably nearing practical limits of such achievements.

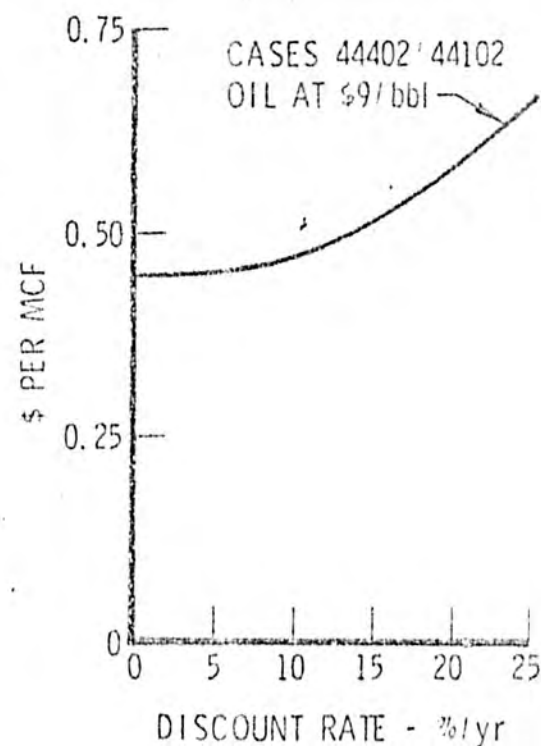
Producers Incremental Unit Cost of Gas

MAXIMUM PRESSURE MAINTENANCE IN SADLEROGHIT RESERVOIR

2.5 BCFD GAS SALES vs NO GAS SOLD

$$P_G = \frac{\sum \frac{P_O(1-T_O)\bar{Q}_O^t - \bar{C}^t}{(1+R)^t} - \sum \frac{P_O(1-T_O)Q_O^t - C^t}{(1+R)^t}}{(1-T_G) \sum \frac{Q_G^t}{(1+R)^t}}$$

- P_G = INCREMENTAL UNIT COST OF GAS (\$per MCF)
 P_O = WELLHEAD PRICE FOR OIL (\$per barrel)
 T_G = SEVERANCE TAX ON GAS
 T_O = SEVERANCE TAX ON OIL
 Q_G = NET VOLUME OF GAS SOLD (MCF)
 Q_O = NET BARRELS OF OIL SOLD IN CONJUNCTION WITH Q_G
 $\bar{Q}_O$ = NET BARRELS OF OIL SOLD IF GAS WERE NOT SOLD
 $\bar{C}$ = DEVELOPMENT COSTS IF GAS WERE NOT SOLD
 C = DEVELOPMENT COSTS IF BOTH GAS AND OIL WERE SOLD
 R = DISCOUNT RATE
 t = YEARS



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Replies to Questions
from
Alaska State Legislature - Joint Gas Pipeline Impact Committee
Concerning
"The Prudhoe Bay Natural Gas Reservoir and Related Materials"

1. A and B

We do not have a single discount rate that we apply to all oil field projects. We use a range of rates to investigate the sensitivity of this factor, and to cover a range of risks that we judge might occur, consistent with good business practice.

15-20 mbl

2. A and B

There are circumstances under which a requirement to re-inject all the gas produced might lead to a reduction in the rate of oil recovery and the loss of ultimate oil recovery. However, these are hypothetical circumstances; under good reservoir management schemes we would inject water if necessary in sufficient quantities to prevent this happening.

C

Yes, there are circumstances where gas injection is more costly than gas production for sales. The factors that must be considered are:

- i. The cost of gas injection equipment.
- ii. The cost of gas sales processing equipment.
- iii. The cost of water injection to offset gas sales.
- iv. The wellhead price of gas.

3. A

The estimate is reasonable.

B

The amounts of fuel gas used in reinjection and in sales gas processing are about the same.

3. C

No.

D

Never under good reservoir management.

E

It should all be recoverable.

4. A

The well drilling/workover costs are reasonable.

Quantity dependent costs are reasonable direct operating costs.

B

Water injection facilities plus water injection wells are estimated to cost \$1.3 billion.

Gas conditioning plant additions for gas sales to augment the compressors used for injection we estimate at \$500 million.

FPC
gas processing
at well
The reason for the extra plant required for gas sales is that the reinjected gas contained about 12% carbon dioxide plus heavy hydrocarbon gases. These gases would be removed before transmitting the nearly 100% methane through a pipeline.

5. A and B

BP Alaska has committed to negotiate a gas sales contract with a gas company. No specific price is mentioned within the contract but would be the highest prevailing price on the North Slope.

6. A

Some of the heavier hydrocarbons are recovered before the gas is reinjected. They are retained in the crude oil. The remainder are initially reinjected.

B

More of the heavier components will be removed when the gas is processed for sale. As much as possible of these products will be blended with the crude oil; the remainder could be used as fuel on the field, thus releasing more natural gas.

C

No commitments have been made.

7. A and B

The sharing of oil and gas production on the field is being discussed in unitization meetings that are in progress. This allocation will be related oil and gas in place.

C

We do not believe there will be a loss of oil recovery from gas sales.

8. A

No, the Study estimate of \$3.8 billion is too high.

unless includes operating costs

B

Our estimate for the total investment cost, including water injection for gas sales of 2.5 BCF/Day, is \$1.8 billion.

9. A

The Study estimate is too high for two reasons:

- (1) Total investment for gas sales is too high (see 8. B).
- (2) No oil loss is expected.

B

The reservoir is complex and the productions of oil and gas are interrelated, and pre-unit committees are now working on the allocations of costs between oil and gas productions. Until these are resolved we cannot be specific about production costs.

10. A and B

We would not normally produce a reservoir where costs exceed revenue. However, Prudhoe Bay contains both oil and gas and we would look at the overall benefits of producing both, as their production costs are inter-related.

C

We do not foresee any.

11. A and B

The maximum gas production rate of 2.5 billion sc/day is reasonable. It is, however, dependent on two factors:

- (a) An oil production rate of 1.5 millions b/d which will produce about half the gas.
- (b) Injection of water as necessary into the reservoir to replace the gas voidage in the gas cap zone of the reservoir.

December 10, 1975

hydrostatic
tests

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

Joint Gas Pipeline Impact Committee
HEARINGS
December 10-11, 1975

Senator John Rader opened the meeting. Senator Kay Poland made the motion that John Rader be Chairman. Senator John Huber seconded that motion. Senator John Rader was then made Chairman and Representative Clark Gruening was made Vice-Chairman.

The following is a brief summary of the December 10 and 11 Hearings. A more detailed transcription will be made.

December 10:

Forrest Garb, President of H.J. Gruy and Associates presented testimony in the morning

December 10:

The afternoon testimony in answer to Gregg Erickson's questions was presented by B.P. Alaska, Kenneth Keep; Exxon Co. USA, Justin Miller; and ARCO, Howard Slack. Each submitted written statements.

December 11:

The Department of Revenue, Tom Williams of the Petroleum Revenue Division spoke on revenue from natural gas production and answered questions from Eric Eckholm's letter. David Knudsen of the Petroleum Revenue Division continued to answer questions favoring a trans-Alaska line as being more beneficial with higher revenues to the state than the Arctic Gas route. The net present value today being \$100-200 million. He also mentioned that deregulation of natural gas will not lead to instantaneous release of natural gas supply; it will not create new supplies. There is no alternative cheap resource. The establishment of a well head price lies between 50¢-\$1.00. Continual change disrupts an exact figure.

December 11, afternoon:

Guy Martin, Commissioner of the Department of Natural Resources presented a brief written statement and an outline for subsequent testimony: a. demand vs. surplus; b. reservoir study implications; c. status report of Royalty oil and gas Board. He pointed out that the surplus study will change having to deal with projections of state needs to match time period for need. It is difficult to make any reliable projection for a 10-15 year period.

Pat Dobey, Division of Geological & Geophysical Survey presented map scenarios of Open File 90-92 dealing with how we've used energy in Alaska in the last three years to 1974. Last year, 1974, Bof was actually used from what came out of the second.

The Reservoir Study is a conservation tool. It was mentioned that early production of gas does have implications on the production of oil.

Howie Hamilton from the Division of Oil and Gas also presented map scenarios

Witnesses appearing before the Committee were Arlon Tussing, ISEGR; John C. Bennett, El Paso Natural Gas Co.; Amos Matthews, Alaskan Arctic Gas Co.; and Dr. Vic Fischer, Director ISEGR who recommended that a study be made of each route: El Paso and Arctic as each have different economic affects.

Following was a short business meeting that closed the day.

Two motions were made during the business meeting. One motion made by Senator Huber to allocate \$500 for a study of methanol was defeated.

Another motion allowing staff to continue working for the Committee in Juneau was carried.

Legal Division
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Anchorage, Alaska 99510
Telephone 907 277 5637

M. K. Singletary
Regional Attorney



December 8, 1975

Joint Gas Pipeline Impact Committee
Alaska State Legislature
425 G Street, Suite 750
Anchorage, Alaska 99501

Attn: Mr. Eric Eckholm

Gentlemen:

Enclosed for the Committee's consideration is Atlantic Richfield Company's response to the list of questions submitted with your letter of December 19, 1975.

It is presently contemplated that Howard A. Slack, Vice President and Resident Manager, will make a brief statement on behalf of Atlantic Richfield Company during the hearing on December 10.

Very truly yours,

M. K. Singletary

MKS:ajd

Encl.

CC: H. A. Slack

ATLANTIC RICHFIELD COMPANY TESTIMONY
JOINT GAS PIPELINE IMPACT COMMITTEE HEARING
ALASKA STATE LEGISLATURE
ANCHORAGE, ALASKA - DECEMBER 10, 1975

- 1A. What discount rate does your firm use in evaluating field development investment of the sort envisaged in the Prudhoe Bay area?
- 1B. If more than one rate is used, indicate the reasons and circumstances appropriate to each rate.

Our Company's evaluations of field development investments are based on economics after federal income tax, using a single discount rate with all risks treated as a part of project costs. The specific discount rate we use is confidential, but it primarily reflects the cost of capital and varies with time. The Aerospace study based its economic evaluations on a discount rate of 10% before federal income tax and assumed no inflation. This rate of return is too low for evaluating field development investments.

The total economics of a field that is being developed should reflect a much higher rate of return than is used as the economic criterion for incremental field development investments (i.e., much higher than the discount rate discussed above).

In general, a field that is being developed represents a successful project. A company's successes must pay for their unsuccessful ventures such that the company can make a reasonable rate of return on their overall exploration and development program. A report entitled "Calculation of New Oil Costs, United States, Years 1959 through 1974" dated May 1, 1975, which was prepared by LaRue, Moore and Schafer, Petroleum Consultants, as a basis for testimony by

Mr. Robert R. Nathan, Robert R. Nathan Associates, Inc., before the Senate Committee on the Interior on April 28, 1975, stated that a 15% discounted cash flow rate of return to the producers (after federal income taxes) is "the minimum required in our opinion, to maintain exploration levels."

- 2A. Are there any circumstances under which a requirement to reinject all gas produced could lead to a reduction in the rate of oil recovery or in the ultimate recovery?
- 2B. If so, explain those conditions and estimate the amount of reduction.

From a reservoir mechanics standpoint, there is no reason prolonged reinjection should affect oil producing rate or ultimate recovery. However, from an economics standpoint, there probably would be a point where it would be impractical to add injection compressor capacity to maintain the oil rate. At this point the oil producing rate could be sustained and perhaps increased if gas were sold. An additional one billion cubic feet of gas per day could be compressed to sales line pressure with the same compression equipment initially used for reinjecting gas. The increased capacity to handle produced gas in this manner could accommodate increased oil rates from the existing wells.

- 2C. Are there any circumstances under which the reinjection of gas could be more costly than production of gas for sale?

All the cases we have studied for reinjection of gas include the eventual sale of gas. The reinjection case in the Gruy study terminates in the year 2000 without gas sales. It has no costs or revenue for gas sales. When gas is eventually sold, gas reinjection over a long term should be more costly than early gas sales, both in terms of gas

handling equipment and operating costs. This would occur because the same sales gas compression and processing facilities would be required for late gas sales as for early sales. However, during the prolonged injection period, more costly compression equipment would be required because two stages of compression are needed to reinject gas while only one is required for sales. The long delay of gas sales for reinjection also would extend the producing life of the field, causing additional operating and maintenance costs. Inflation will also cause gas sales to cost more for the delayed gas sales case than for the early gas sales case.

- 3A. The Aerospace study states (p. 3-30) that gas compression for reinjection will require 5% of the gas as fuel. Is this a reasonable estimate?

Yes. Consumption of 5% of the produced gas as compressor fuel for reinjection is a reasonable estimate. An additional 5% would be consumed as fuel in the operation of the separation centers and the power plant, giving a total consumption for field fuel of about 10%.

- 3B. How does this compare with the field consumption of gas to be expected under the assumption of maximum production for sale?

There are, of course, many reservoir management alternatives in the gas sales and reinjection programs with many uncertainties regarding fuel consumption in each program. However, we believe that field fuel consumption for a long-term gas reinjection program would be essentially the same as for a program involving early gas sales. Our conclusion is based on the assumption that the reinjection program would provide for gas sales to begin well before oil production ceases.

- 3C. Neglecting the gas used as compression fuel, is there any reason why all the reinjected gas could not eventually be recovered?

No. From a reservoir mechanics standpoint all the reinjected gas could be recovered. However, when the economics of the operation are considered, all the reinjected gas may not be recovered if a long-term reinjection program were employed.

- 3D. Assuming that all gas was reinjected, at what point do you estimate the total quantity of gas reinjected would equal the total recoverable gas reserves contained in the reservoir?

The timing for reinjected gas volumes to equal the total recoverable gas reserves is, of course, dependent on the reinjection rate. If prolonged gas injection were anticipated, additional compression might be added to increase the injection rates. Even with the increased rates, the earliest possible timing for injected volumes to equal the total recoverable gas reserves would be about 30 years. With no increased injection capability, the timing would be about 45 years. The utility for such information is not readily apparent. It should be pointed out that some of the reinjected volume would be gas that was produced and reinjected several times, whereas part of the gas that would ultimately be recovered would not have been produced in reaching the described balance.

- 3E. Would this quantity (less that consumed in reinjection) actually be recoverable at that point? If more or less, why?

Yes. From a reservoir mechanics standpoint all of the reinjected gas could be recovered. However, when the economics of the operation are considered, all of the reinjected gas at the point described in question 3D, may not be recovered.

- 4A. Are the cost figures used in the H. J. Gruy model (Aerospace 3-23 and Gruy p. 10) reasonable?

The cost estimates used in H.J. Gruy's study do not appear to be unreasonable although they are lower than our current projections. Their estimates are, however, in 1975 dollars and are quite different from the actual expenditures in current dollars (i.e., in the year they are spent) expected to be made for field development and operations. There is a great deal of uncertainty in predicting future investment and operating costs for the Prudhoe Bay Field because of major changes in inflationary trends during the past few years and the complications of operating in the harsh Arctic environment.

- 4B. Aerospace (p. 3-22) indicates that the quantity dependent costs are in addition to the costs of water treatment plants, but no cost figures are provided for such plants. Apparently there are similar additional capital costs associated with gas processing to control the water and hydrocarbon dewpoints and to remove carbon dioxide (Aerospace Report p. 3-8). Please explain the relative costs of those activities and any other related activity necessary to prepare the gas for sale so that the Committee can have a general idea of why the costs of producing the gas for sale are higher than the costs of production for reinjection?

The Gruy reinjection case terminates in the year 2000 and has no costs or revenue for gas sales. As indicated in our response to Question 2C., the costs of producing gas for sale should not be higher than the costs of reinjection with eventual gas sales. Regardless of when the gas is sold, carbon dioxide and certain natural gas liquids will be removed from the gas stream and the stream will be dehydrated in a gas conditioning facility prior to sales. This facility will be designed to make the Prudhoe Bay gas production meet pipeline quality specifications. The cost of constructing the gas conditioning facility is estimated to

be about \$900 million (current dollars based on construction timing for gas sales beginning in 1982).

- 5A. Have you entered into any agreements for the sale of your share of the Prudhoe Bay gas which would require you to produce the gas even if the price obtainable for it was very low?

The three funding agreements into which we have entered provide the funding party with the exclusive right to negotiate for a portion of Atlantic Richfield's gas in the Prudhoe Bay Field subject to regulatory approvals and various termination provisions on the part of each party dependent on certain happenings or occurrences.

We do not expect the price for Prudhoe Bay gas to be so low that there will be any question with regard to the economic desirability of sale of the gas. Each of the contracts we have made provides for a mechanism for determining the applicable wellhead price in the event the gas continues under price regulation or becomes exempt from price regulation. In the event the contracts are not subject to price regulation, the contract price clauses would ensure that the sales prices would reflect fair market value.

If, on the other hand, the prices under the gas contracts to be negotiated are subject to FPC regulations, then the price would be the highest just and reasonable price set by the Federal Power Commission. At this time we do not know what this price would be, but the present FPC nationwide price for gas at the wellhead is 51¢ per MCP plus applicable BTU adjustment and sales taxes, and we feel sure that the nationwide price for gas at the time of first sales from Prudhoe Bay (1981-1983) will be

considerably higher. We recognize that the present nationwide area rate price of the FPC does not apply to Alaskan gas, and we would expect the Alaskan price to be higher than the nationwide price because of the greater costs involved in Alaska.

- 5B. What minimum price, if any, is mentioned in any gas sales or option agreement covering North Slope gas to which your firm is a party?

As mentioned in our response to Question 5A., we have entered into funding agreements with Pacific Lighting Gas Development Company, Panhandle Eastern Pipe Line Company, and Texas Eastern Transmission Corporation. The contracts between Atlantic Richfield and Panhandle Eastern Pipe Line Company and Texas Eastern Transmission Corporation provide, in part, as follows (the contract with Pacific Lighting Gas Development Company provides roughly the same):

"(a) The contract gas sales price under regulation shall be negotiated to the highest of (1) the highest price provided in any long-term Prudhoe Bay contract for delivery of substantial volumes of gas to the lower 48 states or (2) the highest applicable just and reasonable rate adopted by the Federal Power Commission of (3) the highest nationwide area rate in effect in 1975 adjusted for applicable Alaska taxes and inflation to date of first deliveries.

"(b) The contract gas sales price absent regulation shall be negotiated to the highest of (1) commodity value in Buyer's market less treating and transportation costs to such market, (2) any higher price then payable under any other long-term Prudhoe Bay

contract for delivery of substantial volumes of gas to the lower 48 states, and (3) a negotiated minimum price not less than the highest nationwide area rate in effect in 1975 adjusted for Alaska taxes and inflation to date of first deliveries.

"(c) Other pricing provisions shall include but not be limited to full BTU adjustment, 100% tax reimbursement, excess royalty clause, escalation and redetermination clauses and Seller's right to file for special relief."

- 6A. What will become of the heavier hydrocarbons contained in the gas stream (ethane and heavier) if the gas is reinjected?

We have no plans to initially construct facilities for removal of heavier hydrocarbons from the gas stream. These hydrocarbons will be reinjected along with the gas. If a long delay in gas sales were incurred, the economics of installing facilities to extract the heavier hydrocarbons prior to gas sales would be studied.

- 6B. What will become of the heavier hydrocarbons contained in the gas stream (ethane and heavier) if the gas is sold?

When the gas is sold, most of the ethane and heavier will remain in and be sold with the gas stream or will, if Atlantic Richfield exercises an option in its gas contracts, be recovered from the gas stream, taken in kind, and utilized elsewhere. Certain liquids will be separated out in the gas conditioning plant. Atlantic Richfield retains the option to take these liquids or leave them for disposal by the gas purchasers.

6C. To what extent, if any, has your firm committed itself to the sale of these heavier hydrocarbons?

None. As mentioned in our response to Question 6B, above, Atlantic Richfield has the option to further process the gas stream for removal of ethane and heavier liquids.

7A. Will the proceeds of the production of gas and oil be shared by the producers on the basis of original oil and gas in place?

Proceeds of production will not, of course, be shared on any basis. The owners of tracts overlying the Prudhoe Bay Field signed a Letter of Intent which was submitted to the State at the Prudhoe Bay Field Rules Hearing in 1969. The letter provided that each owner would work toward a unit agreement providing for the development, production and operation of the field as if its area had been included in a single lease. The Letter of Intent provides that ownership in separate oil rim and gas cap participating areas within the unit is to be based upon oil and gas originally in place with each tract in each participating area being allocated its appropriate percentage of production. The field owners are currently involved in unitization negotiations which should resolve all the details of the production sharing problem.

7B. If not, then how?

As indicated in our response to Question 7A., final agreement has not been reached on all the details for sharing oil and gas production from the Prudhoe Bay Field.

If as is indicated in Gruy, the production of gas for sale results in a loss of oil, what principle will govern the apportionment of this loss among the field's several owners?

Provisions will not be made for sharing any hypothetical "loss of oil" or gain of oil, but only for sharing the oil and gas actually produced. The so-called "loss" of production in Gruy's report is in reality a difference in estimates of recovery through the year 2000 for different reservoir management programs determined theoretically through the use of a mathematical reservoir simulation program.

- 8A. The Aerospace study indicates that the future field development costs of gas production for sale exceed the costs of field development under a 100% reinjection assumption by a substantial amount (Aerospace - p.19 indicates a difference of \$3.8 billion). Does your firm generally believe this to be a realistic prediction?

We have not studied the same cases for gas sales and reinjection as those provided by Gruy for the Aerospace study. The reinjection case they have studied terminates in the year 2000 and has no costs or revenue for gas sales. We do not believe that a program which does not provide for eventual gas sales is realistic. We also note that the Aerospace cases do not appear to be optimized and improvements might be made which would reduce the difference between the two plans in both field development costs and ultimate recovery. Although we do not have adequate data to determine the validity of the quoted \$3.8 billion difference in field development costs for the assumed conditions of the two Aerospace cases, we have reviewed component parts of Gruy's cost estimates and do not find them to be unreasonable.

- 11
- 8B. If so, please explain the reason for this \$3.8 billion difference. If not, why?

It is our understanding that the \$3.8 billion difference in development costs between the gas sales and reinjection cases includes both capital expenditures and operating costs. However, we suggest that Gruy is in a better position to report on the specific causes for the difference.

- 9A. Pages 3-37 of the Aerospace Report indicate that the total costs of producing the gas considering the lost oil production (at \$9/bbl.) and the actual field development costs under maximum pressure maintenance would be \$7.251 billion. Is this a reasonable figure? If not, what would be a reasonable estimate?

\$3.8 billion of the total \$7.251 billion reported cost of gas production represents the added field development costs discussed in Questions 8A and 8B. The remaining \$3.45 billion is based on the 400 million barrels "lost oil production" with gas sales as compared with a reinjection program.

The Aerospace report indicates that 400 million barrels less oil will be recovered by the gas sales program as compared with the reinjection program but states on pages 3-34 that "it is reasonable to suppose that the small percentage reduction in oil recovery forecast between the two cases would be reduced even further through practical experience gained in operating the field." We are certainly in agreement with this conclusion.

For an analysis of hypothetical hydrocarbon losses to be complete, the recovery of gas, natural gas liquids, and condensate, as well as oil, must be considered in comparing

gas sales with a reinjection program. Although we have not quantified the effects of early gas sales on hydrocarbon recoveries other than for black oil, we believe that directionally earlier gas sales will provide a greater recovery of natural gas, natural gas liquids and condensate. It is also important to note that the gas sales case would bring to the U.S. energy market 42% more energy prior to the start of the 21st century than would the gas reinjection program.

- 9B. The Aerospace Report indicates that assuming a \$9/bbl. price for oil and a 10% discount rate, the cost of gas production will be \$.47/MCF (Aerospace p. 3-38 and p. 3-39). Is this a reasonable figure? If not, what would be a reasonable figure?

The 47¢/MCF gas production cost indicated in the Aerospace report is part of a national economic benefit analysis and is not indicative of the true cost of production. The assumptions that go into the national economic benefit analysis which make it unrealistic from a producer's standpoint are: (1) all costs are in 1975 dollars, (2) federal income taxes are excluded, and (3) the 10% before tax discount rate is not sufficient in the current high inflation environment to provide an adequate incentive to find new gas reserves. The current replacement cost for gas reserves is much higher than the reported 47¢/MCF.

- 10A. Would your firm be willing to develop the field for gas production (for sale) if the expected revenue from the gas sales were less than the cost of its production? (In other words, are there any circumstances under which your firm would go ahead with development for gas sales even if the present net worth of the field (or your part of it) were to be reduced thereby?)

No.

- 10B. Are there any circumstances under which the production of natural gas could be subsidized by the production of oil?

We do not foresee any circumstances where production of natural gas (for sale) from the Prudhoe Bay Field would be subsidized by the production of oil.

- 10C. Are there circumstances under which a firm could be compelled to produce the gas even though such production did not make economic sense?

Federal Power Commission regulations require that the price of gas sold in interstate commerce be "just and reasonable." This, by definition, requires that a reasonable profit be realized on such sales. We anticipate no circumstances which would compel a firm to produce the gas (for sale) even though such production would be uneconomic.

- 11A. The Aerospace study seems to indicate that the maximum gas production from the Prudhoe Bay reservoir sustainable for any substantial period of time without undue loss of oil recovery is about 2.5 BCF per day. Some pipeline feasibility calculations seem to be predicated on a higher rate of production. Is the Aerospace system realistic?

The gas sales rate that could be sustained from the Prudhoe Bay reservoir for any substantial period of time is, of course, sensitive to the starting date for gas sales. Based on the assumed gas sales date of the Aerospace study, we believe that the 2.5 BCF per day estimate is realistic.

- 11B. If not, what is a realistic system?

As indicated above, we believe that the Aerospace system is realistic.

Replies to Questions
from
Alaska State Legislature - Joint Gas Pipeline Impact Committee
Concerning
"The Prudhoe Bay Natural Gas Reservoir and Related Materials"

1. A and B.

We do not have a single discount rate that we apply to all oil field projects. We use a range of rates to investigate the sensitivity of this factor, and to cover a range of risks that we judge might occur, consistent with good business practice.

15-20 mbl

2. A and B

There are circumstances under which a requirement to re-inject all the gas produced might lead to a reduction in the rate of oil recovery and the loss of ultimate oil recovery. However, these are hypothetical circumstances; under good reservoir management schemes we would inject water if necessary in sufficient quantities to prevent this happening.

C

Yes, there are circumstances where gas injection is more costly than gas production for sales. The factors that must be considered are:

- i. The cost of gas injection equipment.
- ii. The cost of gas sales processing equipment.
- iii. The cost of water injection to offset gas sales.
- iv. The wellhead price of gas.

3. A

The estimate is reasonable.

B

The amounts of fuel gas used in reinjection and in sales gas processing are about the same.

3. C
No.

D
Never under good reservoir management.

E
It should all be recoverable.

4. A
The well drilling/workover costs are reasonable.
Quantity dependent costs are reasonable direct operating costs.

B
Water injection facilities plus water injection wells are estimated to cost \$1.3 billion.
Gas conditioning plant additions for gas sales to augment the compressors used for injection we estimate at \$500 million.

SPC
low at
of SW
was processing
The reason for the extra plant required for gas sales is that the reinjected gas contained about 12% carbon dioxide plus heavy hydrocarbon gases. These gases would be removed before transmitting the nearly 100% methane through a pipeline.

5. A and B

BP Alaska has committed to negotiate a gas sales contract with a gas company. No specific price is mentioned within the contract, but would be the highest prevailing price on the North Slope.

6. A

Some of the heavier hydrocarbons are recovered before the gas is reinjected. They are retained in the crude oil. The remainder are initially reinjected.

B

More of the heavier components will be removed when the gas is processed for sale. As much as possible of these products will be blended with the crude oil; the remainder could be used as fuel on the field, thus releasing more natural gas.

C

No commitments have been made.

7. A and B

The sharing of oil and gas production on the field is being discussed in unitization meetings that are in progress. This allocation will be related oil and gas in place.

C

We do not believe there will be a loss of oil recovery from gas sales.

8. A

No, the Study estimate of \$3.8 billion is too high.

unless includes operating costs

B

Our estimate for the total investment cost, including water injection for gas sales of 2.5 BCF/Day, is \$1.8 billion.

9. A

The Study estimate is too high for two reasons:

- (1) Total investment for gas sales is too high (see 8. B).
- (2) No oil loss is expected.

B

The reservoir is complex and the productions of oil and gas are interrelated, and pre-unit committees are now working on the allocations of costs between oil and gas productions. Until these are resolved we cannot be specific about production costs.

10. A and B

We would not normally produce a reservoir where costs exceed revenue. However, Prudhoe Bay contains both oil and gas and we would look at the overall benefits of producing both, as their production costs are inter-related.

C

We do not foresee any.

11. A and B

The maximum gas production rate of 2.5 billion sc/day is reasonable. It is, however, dependent on two factors:

- (a) An oil production rate of 1.5 millions b/d which will produce about half the gas.
- (b) Injection of water as necessary into the reservoir to replace the gas voidage in the gas cap zone of the reservoir.

December 10, 1975

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12.13*

STATEMENT BY HOWARD A. SLACK,
VICE PRESIDENT AND RESIDENT MANAGER,
ATLANTIC RICHFIELD COMPANY,
TO THE JOINT GAS PIPELINE IMPACT COMMITTEE
ANCHORAGE, ALASKA

DECEMBER 10, 1975

Mr. Chairman and members of the Committee. We have previously submitted for your consideration answers to the questions posed in your letter of November 19 concerning the Prudhoe Bay natural gas reservoir and related materials. While these answers speak for themselves, I think it is appropriate to note that we are not certain that we fully appreciated the thrust or utility of some of the questions. Further, some of the questions involved so many variables that it was difficult, if not impossible, to provide answers which satisfy all of the variables involved. Thus, some further elaboration or clarification may become appropriate incident to your further consideration of this matter.

Now I would like to briefly summarize the thrust of our answers.

1. Atlantic Richfield Company supports the early sale of Prudhoe Bay natural gas and believes it can be produced and marketed at a competitive price and generate a reasonable return to the producers, the pipeline owners and the State of Alaska. We are firmly convinced that Prudhoe Bay gas can make a substantial contribution to the Nation, both in terms of net economic benefit and in terms of achieving positive steps toward energy independence. Further, early gas sales will allow condensate and natural gas liquids to be recovered when their yields are the highest. In addition, we would expect early gas sales to achieve a greater gas recovery than prolonged reinjection.

2. The Committee's letter of October 23, 1975 requested comments on the Aerospace Study's reported loss of 400 million barrels of oil resulting from early gas sales. The Aerospace Report indicates that 400 million barrels less oil will be recovered by the gas sales program as compared with the reinjection program, but states on page 3-34 that "It is reasonable to suppose that the small percentage reduction in oil recovery forecast between the two cases would be reduced even further through practical experience gained in operating the

field". We are certainly in agreement with this conclusion. In our opinion, this so-called "loss" of 400 million barrels is in reality nothing more than the difference in estimates of recovery through the year 2000 for two different and theoretical reservoir management programs. Further, the "loss" only commences to occur after 1992 and it is probable that experience gained in the field prior to that time would allow variations in well completion intervals, production volumes, water interjection locations, etc. to reduce this theoretical difference in oil recovery.

Thank you very much for your interest and attention.