

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

513 SCOM15: HOUSE/SEN. SP. COMM. SALE ROYALTY GAS 1977-78 513

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

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

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

the Northwest Territories.

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

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

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

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

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

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

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

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

EL PASO NATURAL GAS COMPANY
NATURAL GAS CONSUMPTION FOR THOSE
STATES SERVED WHOLLY OR IN PART
Calendar Year 1975

Exhibit 13

<u>STATE</u>	<u>EPNG SALES</u>	<u>TOTAL CONSUMPTION</u>	<u>EPNG PERCENT OF TOTAL CONSUMPTION</u>
Arizona	164,704 MMCF ¹	164,704 MMCF	100.0%
California	1,008,158 MMCF	1,807,604 MMCF	55.8%
Colorado	120 MMCF	290,798 MMCF	<1%
Nevada	28,590 MMCF	60,446 MMCF	47.3%
New Mexico	43,336 MMCF	167,220 MMCF	25.9%
Oklahoma	11 MMCF	639,575 MMCF	<1%
Texas	34,627 MMCF	3,911,026 MMCF	<1%
Utah	19 MMCF	123,098 MMCF	<1%

¹ MMCF = millions of cubic feet

NATURAL GAS CURTAILMENT IN 1976
AND ESTIMATED CURTAILMENT IN 1981
1976

	<u>VOLUME</u>	<u>% OF REQUIREMENT</u>
P 1	0	0
P 2	1,731 MMCF	1%
P 3	35,666 MMCF	16%
P 4	2,862 MMCF	21%
P 5	219,809 MMCF	65%
TOTAL	260,068 MMCF	19%

1981

	<u>VOLUME</u>	<u>% OF REQUIREMENT</u>
P 1	83,071 MMCF	15%
P 2	143,261 MMCF	52%
P 3	254,693 MMCF	100%
P 4	11,440 MMCF	100%
P 5	348,723 MMCF	100%
TOTAL	841,188 MMCF	58%

prepared by El Paso

What is the Alcan Pipeline Project?

The Alcan Pipeline Project is the proposal of the Alcan Pipeline Company, a wholly-owned subsidiary of Northwest Pipeline Corporation, headquartered in Salt Lake City, Utah. Northwest Pipeline owns and operates a 4,400-mile pipeline system extending from the San Juan Basin in New Mexico and Colorado to the Canadian border, serving natural gas customers in seven western states. The company supplies all of the natural gas consumed in Idaho, Oregon and Washington and part of the gas used in Nevada, Wyoming, Utah and Colorado. Northwest Pipeline has assets of more than \$500 million.

On July 9, 1976, the Alcan Pipeline Company filed a request with the Federal Power Commission seeking authorization to construct a 731-mile pipeline in Alaska, utilizing the Fairbanks Corridor / Alcan Highway Route. This pipeline will be part of a proposed new pipeline system to transport natural gas from the Prudhoe Bay on Alaska's North Slope to markets in the lower 48 states.

The planned pipeline would follow established utility and highway corridors in Alaska and Canada and would utilize existing Canadian pipeline systems to deliver the gas to the United States border. This conforms to the Mineral Leasing Act which calls for joint use of rights-of-way to prevent unnecessary scarring of public lands.

Four Canadian Companies — Westcoast Transmission Company Limited; The Alberta Gas Trunk Line Company Limited and its subsidiary, Alberta Gas Trunk Line (Canada) Limited; and Foothills Pipe Lines Ltd. — have entered into an agreement with Alcan and Northwest Pipeline to transport the Prudhoe Bay gas through Canada to the U.S. border and have filed the necessary applications for Canadian regulatory approvals.

Alcan Pipeline's project will be designed to transport all of the Prudhoe Bay gas, up to approximately 2.4 billion cubic feet per day, through a 42-inch diameter pipeline. The pipeline will follow the Alyeska oil pipeline for ap-

Facts about Alcan

The Alcan Pipeline Project is one of three systems currently being considered by the Federal Power Commission for the transportation of Alaskan gas reserves to markets in the lower U.S.

The Alcan Pipeline Route will parallel the Alyeska oil pipeline for 539 miles to Delta Junction, at which point it will proceed along the Haines utility corridor and the Alcan (Alaska) Highway to Fort Nelson, British Columbia and Zama Lake, Alberta. Existing Canadian pipelines will carry the Alaskan gas for redelivery to U.S. transmission companies at three points along the U.S./Canadian border.

New Pipeline: 1,806 new pipeline miles — 731 in Alaska and 1,073 in Canada.

Diameter: 1,499 miles of 42-inch pipe and 307 miles of 36-inch pipe.

Capacity: 2.4 billion cubic feet per day (expandable to 3.1 billion) within three years of operation. Initial capacity of 1.2 billion cubic feet per day.

Cost Estimate: In 1975 dollars, the Alaskan portion of the Alcan Project will cost \$2.3 billion, and the Canadian portion will cost \$2.4 billion. Alcan's total costs, including additional facilities in the lower 48 states, are \$6.3 billion.

Comparative Costs are \$10.4 billion for Arctic Gas and \$6.6 billion for El Paso.

Canadian Associates: Alberta Gas Trunk Line Company Limited and its subsidiary Alberta Gas Trunk Line (Canada) Limited; Westcoast Transmission Company Limited; and Foothills Pipe Lines Ltd.

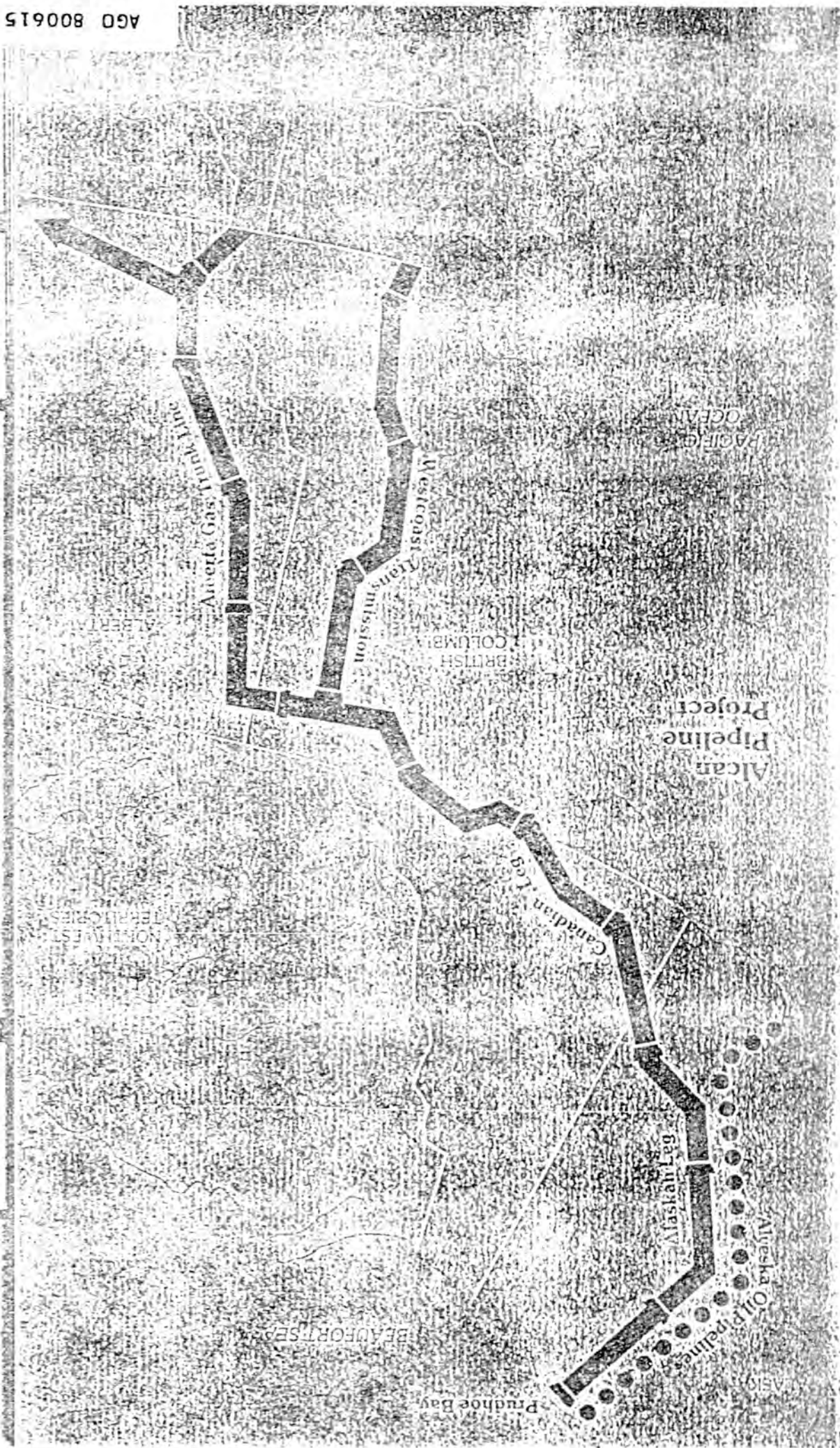
Alcan's Advantages:

- Lowest total investment for transporting Prudhoe Bay gas.
- Lowest delivery costs.
- Earliest delivery date.
- Provides stable economic growth base for the Alaskan interior.
- Least environmental impact.
- Year-round access to all facilities.
- Can be built independent of Canadian decision to develop its frontier gas reserves.



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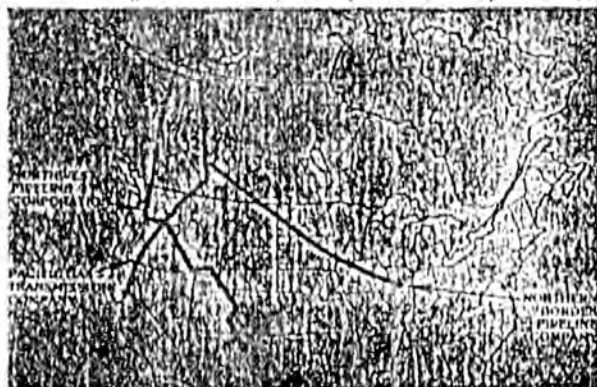




proximately 539 miles to Delta Junction, south of Fairbanks, where it would then parallel the Alcan (Alaska) Highway to the Yukon border.

At the Alaskan/Yukon border gas would be delivered to a new pipeline to be constructed by a Canadian company, Foothills Pipe Lines Ltd., which would continue the transportation of gas through a 42-inch pipeline along the Alcan Highway to the Yukon-British Columbia border and then by Westcoast Transmission Company Limited to Fort Nelson, British Columbia.

At Fort Nelson, a portion of the gas would be diverted into the expanded existing system of Westcoast for ultimate delivery to the United States at an interconnecting point on the border near Sumas, Washington, where the gas will be received by the Northwest Pipeline system for delivery to western markets.



The Alcan Project will provide for direct pipeline delivery of Alaskan gas to markets in the lower 48 states.

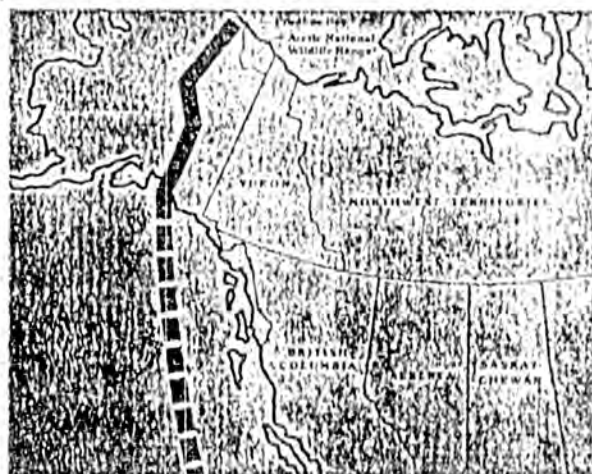
The remainder of the gas would be transported from Fort Nelson to Zama Lake, Alberta, through a new pipeline for delivery at Zama Lake to Alberta Gas Trunk Line Company Limited. Alberta Gas Trunk Line would then transport the gas through its expanded existing system for delivery to Enpress, Alberta, and to Coleman, Alberta where the existing Alberta Natural Gas Company line would carry the gas to Kingsgate, British Columbia for delivery to the Pacific Gas Transmission system, which would transport the gas to California.

From Enpress, Alberta, Foothills would construct a new pipeline to Monchy, Saskatchewan and from there, gas destined for the Midwest and Eastern regions of the United States could be delivered through the Northern Border Pipeline, presently pending before the FPC.

What are the Alternative Proposals?

The El Paso Natural Gas Co. proposes to construct a trans-Alaska pipeline that would roughly follow the Alyeska oil pipeline. Under El Paso's proposal, gas would be liquefied in Alaska and transported as LNG to southern California where the gas would be delivered from the West Coast to the rest of the U.S. by a displacement mechanism which has not yet been defined.

The proposal of the Arctic Gas Group is an all-land route that would begin in Prudhoe Bay, cut straight across the virgin wilderness areas including the Arctic National Wildlife Range, to Canada's Mackenzie Delta, then south to the U.S.-Canadian border, where proposed companion lines would carry the gas to the eastern and western U.S.



EL PASO LNG ROUTE



TRANS-CANADA ROUTE OF ARCTIC GAS

Economic Advantages of Alcan

The total cost of the Alcan Project, including facilities for transporting the gas within the lower 48 states, is \$6.3 billion in 1975 dollars. This compares with \$10.4 billion for the Arctic Gas proposal and \$6.6 billion for the El Paso proposal.

The lowest total cost is a major advantage. The Alcan Project will almost certainly be easier to finance. Capital, like natural gas, is a resource that is limited but very necessary.

This lower total cost makes Alcan transportation costs lower. Figures filed with the Federal Power Commission show that Alcan will be able to transport Alaskan gas to the U.S. at a lower cost than either of the competing projects. We estimate the transportation cost of our service to markets in the lower U.S. to be \$1.35 per million BTU, compared to \$1.59 per million BTU for Arctic Gas, 24 cents higher than Alcan. El Paso's transportation costs, on a comparable basis, are expected to be \$1.69 per million BTU, 34 cents higher than Alcan.

There are many reasons for Alcan's lower total cost and lower transportation cost figures. One is that Alcan is following existing highway and utility corridors all the way. Additionally, use of the existing oil pipeline construction work pad, communications system, airfields and all-weather roads will allow work to begin immediately with a minimum of preliminary construction.

Transporting equipment and supplies to the construction site is a major logistical problem. Without existing roads, the problem is multiplied many times.

New Construction Pad

Arctic Gas proposes construction of snow roads and would have to bring much equipment in by air. Under the Arctic Gas plan, pipeline construction would take place from snow roads during the short winter construction periods.

However, the northern reaches of Canada and the area along Alaska's North Slope are semi-arid regions, with only about 10 inches per year and occurring mostly in summer.

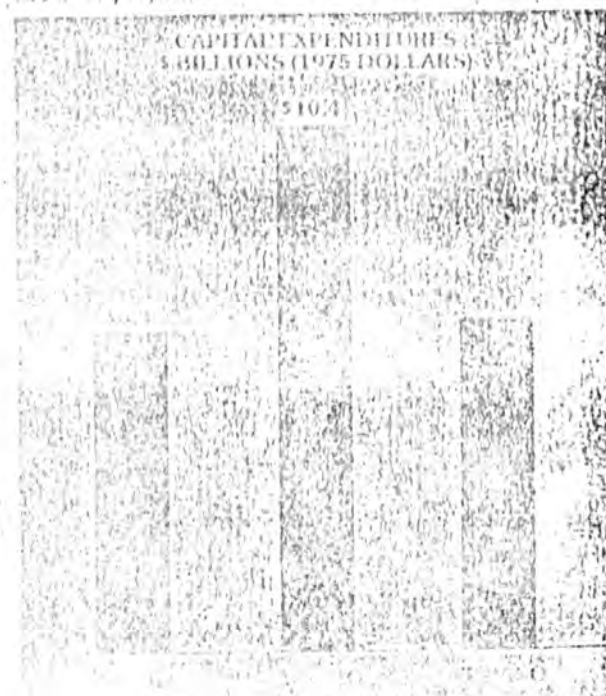
Therefore, annual snowfall would be insufficient for the construction of snow roads and the manufacture of artificial snow would be required. However, Arctic Gas has no prototype machine to produce the snow necessary for the roads.

Even if it were possible, most experts doubt that the snow roads would prevent damage to the highly sensitive arctic soil. They also doubt that there's enough water to make the snow to construct the roads and even if the water can be found, utilizing it in this fashion would almost certainly damage fish populations irrevocably. Use of ocean water is clearly impossible because the high salt content would create permanent damage to the arctic soil and wildlife. In short, Arctic Gas is relying on a totally unproven concept.

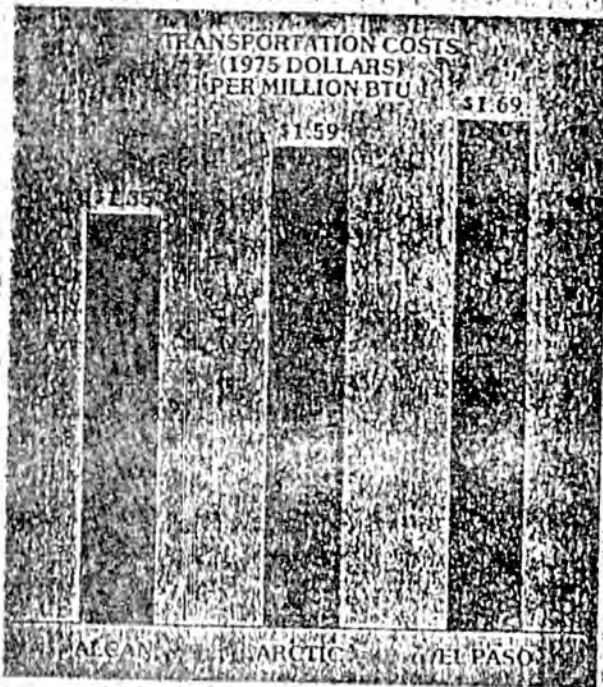
El Paso's prime route generally follows the Alyeska oil line but would require construction of a new work pad. El Paso has filed an alternative route which would utilize 79 per cent of the Alyeska work pad, but still proposes its prime route which would lead to much duplicated work and increased environmental impact.

When the Alcan route departs from the Alyeska oil line but would require construction of a new work pad. El Paso has filed an alternative route which would utilize 79 per cent of the Alyeska work pad, but still proposes its prime route which would lead to much duplicated work and increased environmental impact.

Cost of the Alcan Pipeline Project is \$4.4 billion less than that of Arctic Gas and \$300 million below El Paso's project.



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Alcan delivery cost per million BTU, an all-important cost to the consumer, is the lowest.

route of the oil line near Delta Junction and continues southeast following the Haines pipeline corridor and the Alcan Highway, the highway itself will provide access to all construction areas and will enable Northwest to get supplies and equipment to the work site more quickly and with less expense.

We believe that utilizing facilities presently available is an important way to keep costs down.

Another area in which we adhere to this philosophy is in the utilization of existing Canadian pipelines. Our Alcan route would tie in to West coast Transmission Company facilities at Ft. Nelson, British Columbia and to Alberta Gas Trunk Line facilities near Zama Lake, Alberta. These Canadian lines have excess capacity at present and can be "looped" to handle more of the Alaskan gas as it comes on stream.

Unlike Arctic Gas, we see little reason for an entirely new pipeline in areas where existing pipelines can do the job. This is another reason why Northwest can deliver the gas two years sooner than Arctic Gas or El Paso.

Time Means Money

Those two years mean money. If men and equipment are on the job two years longer, it simply stands to reason that costs will be substantially higher, not only because of the amount of time but because of inflated unit costs of labor and equipment.

Constructing the Alcan route as quickly as possible is another way we plan to hold costs down.

Our Canadian associates in the Alcan Project have North America's greatest experience in gas pipeline construction through permafrost. This experience will enable them to hold costs down and complete construction on schedule.

We also chose the 42-inch pipeline because it is the most economical method of transporting a daily volume of from 2.0 to 2.5 billion cubic feet of gas, as projected by Prudhoe Bay producers. Total recoverable reserves in the field are estimated at 26 trillion cubic feet, but Prudhoe Bay is essentially an oil field — not a gas field — and gas production above certain levels may cause an irreplaceable loss of oil in the gas cap. The State of Alaska has the responsibility of deciding how much oil and gas will be produced from the field, and one of the considerations is to adopt a plan which prevents undue loss of oil. For this reason it will be some time before the Prudhoe Bay field produces large volumes of gas. Our system is the only one with flexibility to handle small gas production rates and build up to the volumes which are realistically expected to be produced from the Prudhoe Bay field.

Half for Canada

Arctic Gas is proposing a 48-inch pipeline to carry up to 4.5 billion cubic feet daily. One-half of this capacity is dedicated to Canadian use for transportation of Mackenzie Delta reserves, destined exclusively for Canadian markets. Therefore, Arctic Gas is transporting only 2.25 billion cubic feet daily for U.S. markets. This compares with 2.4 billion cubic feet per day for the Alcan Project. We estimate that the Alcan line is adequate to carry all of the gas production which may be realistically expected from the Prudhoe Bay oil field.

Although Northwest's proposal does not need Canadian gas to operate profitably, it should be pointed out that the Alcan Project is compatible with Canadian plans to develop Mackenzie Delta gas at a later date.

It is definitely in the U.S. national interest to develop Alaskan North Slope reserves quickly and to transport them to energy-hungry U.S. markets. But is it in Canadian interests to develop Mackenzie Delta reserves immediately? This is a question that only Canada can answer.

Some facts are known. The Arctic Gas proposal would force development of Mackenzie Delta gas in the early 1980's. However because of increasing prices and a corresponding reduction in demand — in conjunction with increasing supplies in British Columbia and Alberta — it may not be in Canada's national interest to develop the Mackenzie Delta reserves at this time.

Northwest's proposal gives Canada the option of developing these reserves at a time when they will be most needed to meet the country's long-term requirements. The Canadians have made quite a point of wanting to reserve Canadian gas for domestic use and it is highly unlikely that additional exports from Canada to the U.S. are forthcoming. The Alcan Project can be approved to deliver Prudhoe Bay gas independent of Canada's policy for developing frontier gas.

Environmental Advantages of the Alcan Plan

The pipeline route chosen by Alcan and Northwest has been widely acclaimed as environmentally superior to the other two alternatives. The Federal Power Commission environmental staff and the Department of Interior both favor the Alcan Highway route. This route also has won the support of the Sierra Club, Friends of the Earth, National Audubon Society, Wilderness Society and others, and some of their comments have been included in this brochure.

The reasons for their objections to the Arctic Gas proposal are primarily that it would gouge a pipeline corridor directly across the coastal plain of the Arctic National Wildlife Range, the only large, pristine arctic wilderness area and one of our national wildlife refuges.

Environmental and safety objections have prompted their opposition to the El Paso proposal. El Paso is proposing a complex system

Caribou calving grounds in the Arctic National Wildlife Range.





Alcan would affect no undisturbed wilderness areas.

of gas liquefaction, transportation and regasification in environmentally sensitive areas on a scale never before attempted and not yet proven.

Which brings up another point. These ingredients: new technology, sensitive environments and a large scale relative to previous projects are the major ingredients for mammoth-sized cost overruns. Dr. Arlon Tussing, former chief economist of the Senate Interior Committee and a professor at the University of Alaska, has said that he would not be surprised to see the cost of either the El Paso or Arctic Gas projects exceed \$20 billion.

The Alcan Project, however, has all of the ingredients for realistic costs and the lowest probability for cost overruns. Alcan proposes conventional technology — a 42-inch diameter line at normal pipeline pressures and only traverses environments where construction experience exists.

Environmentalists prefer route of the Alcan Pipeline Project



"(The Wilderness Society) is most pleased to see the filing by Northwest Pipeline Company — at the Federal Power Commission — to construct a transportation system along the existing TAPS Corridor and the Alcan Highway to connect with existing distribution systems in Canada. This route appears to us to be the most environmentally sound."

—Bar Cooke, The Wilderness Society

"The Fairbanks-Alcan corridor appears to be the most environmentally acceptable alternative because it uses a developed transportation corridor which will not degrade the wilderness character of the Arctic National Wildlife Range and obviates the inherent long-term risks of an All-Alaska, LNG system."

—Pamela Rich, Friends of the Earth

"A less elaborate system (than that proposed by either Arctic Gas or El Paso Alaska Company) would certainly benefit the consumer, and a proposal which utilizes existing corridors would have far fewer adverse environmental effects, lower operating and maintenance costs, and less chance of cost overruns than either of those proposed."

—Barbara Heller, Environmental Policy Center

"...there is increasing evidence that the Alcan Highway routing may be the most environmentally preferable of all the alternatives now before us."

—Brock Evans, The Sierra Club



Sheenjek the Arctic Range

"We believe that the Fairbanks highway alternative deserves further analysis and review so that it can be compared with the other two proposed routes. If your (the Senate Commerce Committee's) purpose is to assure more direct delivery of natural gas to the Midwest or Northeast, the Fairbanks route would do it."

—Cynthia E. Wilson, The National Audubon Society

"... the Center favors construction of the gas pipeline in a utility corridor that is already in use with the provision that the pipeline should utilize to the maximum extent facilities that are already built, including highways, construction pad, access roads, material sites, camps etc."

—Peter Scholer, Alaska Center For The Environment

"The staff concludes that the Fairbanks Alternative is the most environmentally acceptable system to transport Prudhoe Bay gas to the lower 48 states."

—Environmental Staff, The Federal Power Commission



"The Fairbanks Route, because it follows the Alaska Oil Pipeline and other transportation routes through Alaska and Canada, would avoid some of the impacts associated with the Applicant's (Alto Gas) proposed route through the Midwest and Northeast."

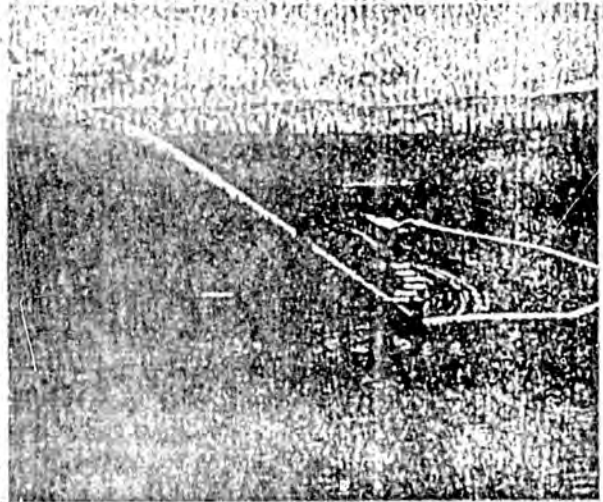
The Department of Interior

"The Fairbanks Alternative is the least environmentally damaging of the alternatives, and, at the same time, it is the most economically feasible."

Director, Bureau of Land Management

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Alcan will utilize the Alyeska work pad.

Other Objections Cited

There have been other objections to the El Paso proposal. El Paso has proposed an LNG liquefaction plant site in an active earthquake zone at Prince William Sound in Alaska. In contrast the Alcan route follows a relatively placid zone north of the most active earthquake areas.

No less eminent a scientist than Dr. Edward Teller of the University of California called for a re-examination of the LNG safety issue. LNG tankers of the size proposed by El Paso have never before been built.

El Paso has proposed an LNG terminal at Point Conception, California, but faces considerable opposition. The Friends of The Earth organization recently reaffirmed its opposition to El Paso's proposed LNG plant sitings at either the undisturbed beach area of Point Conception or the alternative Los Angeles Harbor, which already is overly congested.

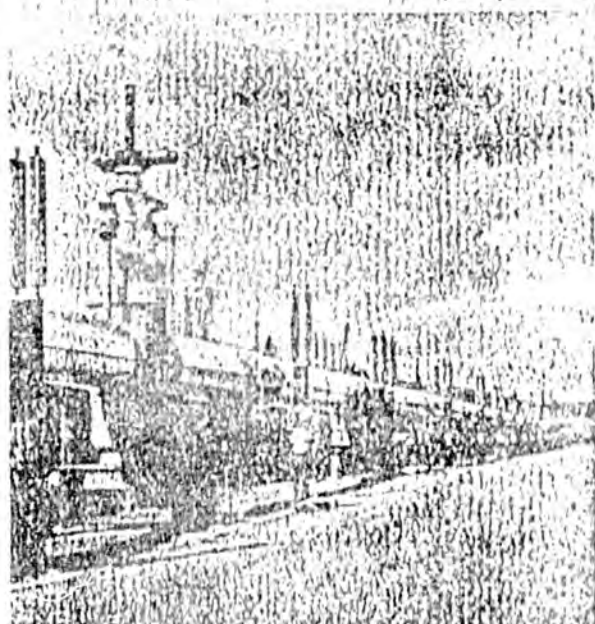
Also in order to site its LNG regasification plant at Point Conception, El Paso must receive approval from a number of California state regulatory agencies.

Uses Less Gas

Few doubt that Alcan will use less gas for transportation than El Paso. Not only does El Paso use gas for transportation but also for liquefaction operations. The pipeline system is also more reliable. Bad weather and rough seas could easily delay shipping, and under the El Paso plan the transportation is at sea.

The pipeline would continue carrying gas in all kinds of weather, and has the added advantage, should a mishap halt service temporarily, of having gas flow restored quickly.

In summary, Northwest's Alcan Project avoids the Arctic National Wildlife Range, disrupts no other wilderness areas, avoids earthquake zones, is more reliable than an LNG system, and would deliver the natural gas where it's needed and when it's needed.



Alcan follows Alyeska oil line for 539 miles from Prudhoe Bay to Delta Junction south of Fairbanks.



Alcan Pipeline 10 million the Alcan Highway from Delta Junction to the coast.

Canadian Issue

Supporters of El Paso have occasionally made exaggerated and sometimes outrageous claims about Canadian interests, institutions and intentions. They would have everyone believe that Alaskan gas will not be secure once it is in transmission systems owned by Canadian companies, that Canada will unfairly tax or otherwise impede the flow of Prudhoe Bay gas to the lower 48.

However, the U.S. and Canada recently initiated a treaty which protects the flow of Alaskan gas in transit through Canada and provides that any provincial taxes and duties must be nondiscriminatory. The movement and the rate of return allowed for transporting the gas will be regulated by Canada's National Energy Board (not by our FPC), not by the provinces. The U.S. has exclusive jurisdiction over the pipeline of our Canadian partners.

Both Alberta and British Columbia have ad valorem taxes, as do the individual states in America, and British Columbia has a fuel tax. Like taxes in the U.S., these taxes would be applicable to the Alcan Project, but only as they are applicable to Canadian gas facilities. In both Alberta and British Columbia, Alaskan gas will be co-mingled with Canadian gas and, as a practical matter, the provinces cannot tax Alaskan gas without taxing the transportation of Canadian gas.

The proposed gas flow is merely a part of the huge economic trade that passes daily between the U.S. and Canada. For example, the oil flow from western to eastern Canada, some 510,000 barrels of crude per day, goes through pipelines in the United States. At Portland, Maine, Canada imports 437,000 barrels of crude oil per day which is transported to Montreal through the United States. All of these 947,000 barrels of oil are under the control of our federal government. Canada also transports approximately 40 percent of its natural gas supplies, or 315 million cubic feet daily, through transmission lines across the U.S. All of this gas is under U.S. government control.

We at Northwest Pipeline believe it's totally unrealistic to talk of Canada discriminating against gas flowing through its pipeline.

14.10

Gas For Alaska

The Alcan Pipeline Project would provide a sound and stable energy base for an expanding Alaskan economy. It is the only plan which provides a high degree of flexibility and is not locked into huge front-end investments.

Since Alcan's capital costs are lower, Alcan management can respond more quickly and positively to Alaska's future industrial requirements. Alcan provides many options for the development and delivery of Alaskan gas. One option is a spur line down the industrial corridor through Anchorage into the Cook Inlet area. Or if gas were discovered along the southern coastal area along the Gulf of Alaska, a spur could be run back to the Alcan line for redelivery of the gas to markets elsewhere in Alaska or to the lower 48 states. The Alcan system provides the flexibility to accommodate new gas discoveries in central Alaska.

As noted, the Alcan Pipeline will follow the old Haines pipeline as far as Haines Junction. If Alaska so desires, the existing spur from Haines Junction to the Haines/Slackway area could be put into service. The Haines line has the potential for transporting about 50 million cubic feet of gas per day. If Alaska decides to develop small industries in this area, Alcan will be able to supply the energy required.

These are only a few examples. There are dozens of other possibilities that could contribute to the long-term growth and stability of Alaska, including development of the petrochemical industry in Alaska and development of Alaska's vast mineral resources. The steps Alaska should take to develop new industry are for Alaska to develop. However industrial, commercial and agricultural development will soon follow gas availability, and in the long term this will provide the jobs and the economic base for orderly and continuing growth in Alaska.

14.11

Conclusion

If American Energy Independence is to become a reality, we must carefully consider the selection of a route and system for bringing North Slope gas to markets in the lower 48 states.

Northwest's Alcan Pipeline Project is the responsible, practical choice. The Alcan plan is in the best interests of the United States because it will bring the Prudhoe Bay gas reserves on stream two years earlier than the proposals of the Arctic Gas or El Paso, and our project will cost billions of dollars less than either of the two alternatives.

We also recognize the need to protect the state of Alaska from haphazard development, and we have designed our Alcan Pipeline in such a way that it will reliably supply the U.S. with vitally needed gas and not invade lands that are not already developed.

In Canada, we will follow the Alcan Highway through the Yukon and British Columbia and, therefore, will not invade Canada's wilderness areas. Because the Alcan Pipeline will not require additional volumes of Canadian gas to operate economically, our plan also will permit the orderly development of the frontier gas reserves at a time of Canada's choosing.

Northwest's Alcan Pipeline Project is superior in several ways: it saves time, money and the environment, and provides for the earliest delivery of Alaskan gas to U.S. markets.

We're convinced Alcan is the best plan — for Alaska, for the nation and for future generations throughout America.



Exhibit 15

COST ESTIMATES FOR GAS TRANSMISSION
LINE AND DISTRIBUTION SYSTEM FOR
MOVEMENT AND USE OF NORTH SLOPE NATURAL
GAS TO INTERIOR ALASKA.

(NORTH STAR BOROUGH AREA)

BY

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FOR

Petroleum Economics - Pet 497

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GENERAL PARAMETERS

In determining the cost of a transmission line and distribution system the following items were considered.

1. Approximately 400 miles of 24 inch pipeline from Prudhoe Bay to the North Star Borough area. \$1,000,000/mi.

2. Assume 10,000 residential hookups at \$2500 each. Tie in for major (industrial) users and physical plant necessary for the distribution system computed at \$25,000,000.

3. Interest rate for distribution system has been calculated using a most favorable municipal bond rate.

4. State royalty share (1/8) of calculated reserves in the Prudhoe Bay field. Approximately 3.5 trillion cu. ft. of natural gas. For the purposes of these calculations, we have estimated usage in the interior at 2 trillion cu. ft. over the 20 year period.

5. All major cost items were extrapolated from known arctic and sub-arctic construction costs.

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COST BREAKDOWN TRANSMISSION LINE.

A. Capital Investment	\$ 400,000,000
B. Interest (20 year) See Computer Printout	401,502,000
C. Operations & Profit	350,000,000
	\$ 1,151,502,000 / 20 years

COST BREAKDOWN OF GAS DISTRIBUTION SYSTEM

A. Capital Investment	\$ 50,000,000
B. Interest (20 year) See Computer Printout	37,739,000
C. Operation & Reserves	200,000,000
	\$ 287,739,000

NOTE: This reserve figure allows for reinjection costs of surplus gas if necessary.

TOTAL PROJECT COSTS OVER 20 YEARS.	\$ 1,439,241,000
CONSUMPTION PER YEAR	100 billion cu. ft.
ROYALTY to STATE at FPC new gas price \$0.52/mcf	\$ 52,000,000 /yr or
	\$ 1,040,000,000 Total
COST PER mcf delivered to users in North	
Star Borough	\$ 1.24/m.c.f.

, GAS TRANSMISSION LINE

LOAN AMOUNT : 400,000,000
 INTEREST RATE (% PER YEAR) 8%
 YEARS 20

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MIN MONTHLY PAYMENT 345.77
 ACTUAL MONTH PAYMENT 3,500,000
 PAYMENTS START(MT,YR) Jan 1980
 PRINT LINE EVERY ? PAYMENTS
 PRINT MAX OF ? LINES

MORTGAGE REPAYMENT SCHEDULE (8.00%)

MONTHLY PAYMENTS \$350.00

M-YR	INT PAY	PRIN PAY	TOT INT	BAL.	
0 0-80				400000.00	
12-80	2614.85	735.15	31692.55	391492.55	
12-81	2553.83	796.17	62678.99	382278.98	
12-82	2487.75	862.25	92900.70	372300.70	
12-83	2416.19	933.81	122294.22	361494.22	
12-84	2338.68	1011.32	150790.82	349790.81	
12-85	2254.74	1095.26	178316.03	337116.02	
12-86	2163.84	1186.16	204789.24	323389.24	
12-87	2065.38	1284.62	230123.14	308523.13	
12-88	1958.76	1391.24	254223.15	292423.14	
12-89	1843.29	1506.71	276986.88	274986.86	
12-90	1718.23	1631.77	298303.39	256103.38	
12-91	1582.80	1767.20	318052.60	235652.58	
12-92	1436.12	1913.88	336104.39	213504.38	
12-93	1277.27	2072.73	352317.89	189517.88	
12-94	1105.24	2244.76	366540.53	163540.52	
12-95	918.92	2431.08	378607.06	135407.05	
12-96	717.14	2632.86	388338.53	104938.52	
12-97	498.62	2851.38	395541.12	71941.11	
12-98	261.95	3088.05	400004.93	36204.94	
12-99	5.65	847.03	401502.68	0.	LAST PAYMENT 852.68

NOTE: multiply all results by 1000

GAS DISTRIBUTION SYSTEM

LOAN AMOUNT 50,000.00

INTEREST RATE (% PER YEAR) 6.5%

YEARS 20

MIN MONTHLY PAYMENT 372.79

ACTUAL MONTH PAYMENT 380,000

PAYMENTS START(MT,YR) Jan 1982

PRINT LINE EVERY ? PAYMENTS

PRINT MAX OF ? LINES

MORTGAGE REPAYMENT SCHEDULE (6.50%)

MONTHLY PAYMENTS \$380.00

M-YR	INT PAY	PRIN PAY	TOT INT	BAL.	
0 0-82				50000.00	
12-82	264.15	115.85	3210.26	48650.26	
12-83	256.39	123.61	6330.12	47210.13	
12-84	248.11	131.89	9353.54	45673.54	
12-85	239.28	140.72	12274.05	44034.05	
12-86	229.86	150.14	15084.76	42284.76	
12-87	219.80	160.20	17778.31	40418.31	
12-88	209.07	170.93	20346.87	38426.87	
12-89	197.62	182.38	22782.06	36302.06	
12-90	185.41	194.59	25074.94	34034.94	
12-91	172.38	207.62	27215.99	31615.99	
12-92	158.47	221.53	29195.04	29035.04	
12-93	143.64	236.36	31001.24	26281.24	
12-94	127.81	252.19	32623.01	23343.01	
12-95	110.92	269.08	34048.00	20208.00	
12-96	92.90	287.10	35263.03	16863.03	
12-97	73.67	306.33	36254.05	13294.05	
12-98	53.15	326.85	37006.04	9486.04	
12-99	31.26	348.74	37503.01	5423.01	
12-00	7.91	372.09	37727.86	1087.86	
3-01	1.83	337.62	37739.45	0.	LAST PAYMENT 339.45

NOTE: multiply all results by 1000

Exhibit 16

ECONOMIC ANALYSIS OF
ALASKAN ROYALTY GAS CONTRACTS

A Report to
STATE OF ALASKA: THE LEGISLATURE

January 1977

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I. INTRODUCTION AND SUMMARY

INTRODUCTION

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

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

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

SUMMARY

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

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

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

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

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

TABLE I-1

RANGE OF POSSIBLE WELLHEAD PRICES FOR
PRUDHOE BAY NATURAL GAS

1980

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

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

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

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

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

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

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

CONCLUSIONS

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

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

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

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

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

II. SUMMARY OF CONTRACT

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

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

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

PROMOTE TRANS-ALASKAN PIPELINE ROUTE

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

ESTABLISH FAVORABLE GAS PRICING STRUCTURE

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

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

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

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

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

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

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

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

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

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

PROTECT ALASKA'S FUTURE GAS NEEDS

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

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

III. SALE OF PRUDHOE BAY NATURAL GAS

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

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

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

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

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

OPEC Production and Pricing

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

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

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

TABLE III-1

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WORLD OIL TRADE

(Million barrels per day)

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

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

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

Source: Jensen Associates, Inc.

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

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

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

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U.S. Price Controls

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

U.S. Energy Conservation

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

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

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

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

Conclusion

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

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

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

Number Two Fuel Oil

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

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

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

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

SNG from Coal

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

Netback Value

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

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

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

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

TABLE III-2

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS

BASED ON NO. 2 OIL

1980

(Dollars per million Btu)

El Paso Route

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

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

Arctic Route

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

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

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

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

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NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS

BASED ON NO. 2 OIL

1985

(Dollars per million Btu)

El Paso Route

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

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

Arctic Route

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

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

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

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

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TABLE III-4

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS

BASED ON SNG FROM COAL

1980

(Dollars per million Btu)

El Paso Route

	<u>Price of SNG Delivered</u> *	- <u>El Paso Transportation Costs</u> **	= <u>Netback Value</u>
Chicago	\$5.46	\$2.75	\$2.71
Chicago	\$5.46	\$2.41***	\$3.05

Arctic Route

	<u>Price of SNG Delivered</u> *	- <u>Arctic Transportation Costs</u> **	= <u>Netback Value</u>
Chicago	\$5.46	\$1.87	\$3.59
Chicago	\$5.46	\$1.61***	\$3.85

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

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

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

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

Contracts

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

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

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

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

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

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

The National Rate and Alaska Gas

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

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

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

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

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

An Area Price Ceiling for Alaska

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

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

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

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

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

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

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

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

Estimation of Alaskan Natural Gas Ceiling Price

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

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

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

F.P.C. Jurisdiction Over Alaska Royalty Gas

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

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

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

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

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

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

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

Vintaging Under the Uniform National Rate

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

The "spud-in" date is the moment of drilling the first foot of a well regardless of the date of completion or recompletion. Well completion refers to the installation of permanent equipment for the production of oil or gas. The date of completion of an oil well or gas well is the date on which the installation of permanent equipment has been completed for the production of oil or gas as reported to the appropriate regulatory agency.

Depending upon the gas field or reservoir drilling development pattern, spud-in date may or may not be a vintaging basis favorable to Alaska. If most gas is produced from wells spudded-in after January 1, 1975, then Alaska may qualify for the highest available national rate for most of its gas if the national rate applies to Alaska. If the royalty share comes from wells spudded-in at a considerably earlier date than the January 1, 1975 cut-off, then Alaska clearly is in a less favorable position vis-a-vis the national rate. At the present time, wells spudded-in on or after January 1, 1973 and before January 1, 1975 receive separate national rate treatment from the F.P.C. while gas from wells commenced prior to January 1, 1973 receive rate treatment under F.P.C. Opinion No. 749 which has established a price of 29.5¢/Mcf nationally for "old" gas. Clearly, the maximization of Alaskan royalty gas revenues will depend on the type of vintaging mechanism allowed under regulation.

Other Vintaging Methodologies

In the evolution of gas pricing regulations, the Federal Power Commission has used various methods for determining the vintage of gas. Other regulatory vintaging methodologies have used contract date, type of gas, date of dedication to interstate commerce, and reservoir discovery date. Table III-5 details the vintaging mechanisms in national and area rate regulation as well as in two proposed 1975-76 deregulation bills.

TABLE III-5
SUMMARY OF NATURAL GAS VINTAGING APPROACHES RELATED TO INTERSTATE PRICE REGULATION

ALLOWED HIGHEST APPLICABLE RATE FOR:_____

VINTAGING APPROACH	Type of Gas		Qualifying Date for "New" Gas Vintage					
	Associated or Oil Well Gas	Non-Associated or Gas Well Gas	Spud-In Date	Recompletion Date	Date of Initial Interstate Dedication	Date of Contract	Date of Reservoir Discovery	RATE ESCALATION
1. <u>National Rate</u>								
a. Opinion 770-A (November 1976)	yes	yes	yes	no	no	no	no	yes
b. Opinion 770 (June 1976)	yes	yes	yes	yes	yes	no	no*	yes
c. Opinion 699-H (December 1974)	yes	yes	yes	yes	yes	no	no*	yes
2. <u>Area Rate</u>								
Permian Basin Opinion 468 (August 1965)	no	yes	no	no	no	yes	no	no
3. <u>1975-1976 Proposed Deregulation</u>								
HR 10480 Krueger- Broyhill Bill (October 31, 1975)	yes**	yes**	yes	no	yes	no	no	As Per Contract
S-3422 Pearson- Hollings Bill (May 12, 1976)	yes	yes	yes	yes	yes	no	yes	yes

*Date of discovery of a new gas reservoir on acreage previously dedicated to the interstate market was a vintaging criterion.

**If producer is not affiliated with a pipeline.

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Contract date and type of gas were used together in the first area rate vintaging methodology (Opinion No. 468 issued August 5, 1965). In this case, an established date (January 1, 1961) was the dividing date between old and new gas with new gas being that which was sold through a contract dated after the January 1, 1961 date. However, this system also vintaged gas on the basis of whether it was gas well gas or oil well gas. All casinghead gas (or oil well gas) was categorized as old gas; only post-January 1, 1961 gas well gas received new gas treatment. Similar vintaging methodologies were used in other area rates established by the F.P.C. with some variations as to the applicable contract vintaging date. The pricing implications for Alaskan royalty gas if vintaging occurs on a basis comparable to area rate regulation are considered elsewhere in this chapter. Alaska should understand, however, that by stating a contractual willingness to accept an area rate with its inferred vintaging mechanism, it may face future rate rulings that are either unanticipated or clearly less favorable than more recent pricing regulations.

Vintaging on the basis of first sales into interstate commerce (under contracts executed after a specified date) has also been used by the F.P.C. in the first uniform national rate (June 1974). This methodology has been superceded by well commencement date vintaging. Date of first sales into interstate commerce appears to be an attractive vintaging basis. It has a clear disadvantage, however, if the market value of gas is expected to rise over the term of the contract by committing all the gas to a price set when market value was lower.

Conclusions

1. No single vintaging method yet applies to Alaskan royalty gas and Federal Power Commission actions on this are uncertain.

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2. Revenues to Alaska for royalty gas sold interstate are highly dependent upon the vintaging method selected.
 3. No single vintaging system is clearly superior to all others, although in general, the more gas that falls into the "new gas" category or vintage, the greater are Alaska's opportunities to maximize royalty revenues.

Vintaging Under Proposed Gas Legislation

Numerous proposals to deregulate or reregulate natural gas pricing were introduced into the 1975-76 Congressional Session, and already in the current Congress eleven bills as of this writing have been proposed. Passage of a particular bill at this time is unclear. However, based on 1975-1976 bills, vintaging is likely to remain an issue in current proposed legislation of great economic significance to Alaska.

The importance of future deregulation or reregulation to Alaska's royalty gas contracts is the possibility that there may be multiple vintages applicable to the Prudhoe Bay gas. That is, depending upon the vintage method, there may be a deregulated and a regulated price in effect at the time of first deliveries.

SEVERANCE TAXES ON ROYALTY GAS

It is possible that \$50 - \$150 million^{1/} in revenue might be lost to Alaska from an interpretation of price in Section 6.2, 6.3, and 6.4. While the Alaskan severance tax legislation currently does not apply to state-owned royalty interests, the price clause should not preclude by omission the collection of a severance tax or revenue in lieu of severance taxes on Alaskan royalty gas in addition to the base price. Under F.P.C. regulation, the price paid to a producer by a pipeline for the working interest share will be adjusted upwards from the ceiling rate to cover severance tax. This payment for severance tax is in turn fully recovered by the pipeline. If a severance tax on the Alaskan royalty interest is not charged in addition to the highest allowable area, national or ceiling rate under some interpretations of the gas contract pricing clauses, the price for royalty interest gas will be less than the price paid by pipelines for the working interest portion. In the condition that Alaska is not subject to F.P.C. jurisdiction, the royalty gas will be sold at the highest price paid by a purchaser which appears to be wording that would cover severance taxes paid by the working interest holder. Given the amount of money involved, we suggest legal review on the point of collecting severance taxes. The possibility for a low price differential on Alaskan royalty gas may be eliminated in one of two ways:

- (1) legislative action to include the royalty interests taken in kind with that production which is subject to a severance tax, or
- (2) a change in the contract which sets the price of Alaskan royalty gas at the highest allowable price plus an adjustment in lieu of a severance tax.

^{1/} For sale of 2.6 tcf at \$0.50 to \$1.50 per million Btu assuming one million Btu per Mcf and a 4% severance tax.

IV. USE OF GAS WITHIN ALASKA

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The State of Alaska is permitted to reduce the volumes of gas sold under the contracts. Any reduction may be made on twenty-four months' notice, or up to specified limits on twelve months' notice, provided the gas is to be used for "domestic or industrial" purposes in Alaska.

As presently written, the contracts do not specify whether the withdrawn gas must be for current or anticipated domestic or industrial needs. It is possible that Alaska might predict or foresee a need for natural gas within the State which extends beyond the term of the contract, or an increasing demand for intrastate gas which will eventually exceed the total volume of royalty gas during the term of the contract. We see no contract impediment to a time exchange of royalty gas which might be worked out with the owners of the working interests.

For example, the province of Alberta follows a rule of protecting provincial requirements for a forecast 30-year period before permitting additional interprovincial sales. A similar rule could be applied by Alaska.

As shown in Table IV-1, natural gas consumption in Alaska during 1975 was 66.8 billion cubic feet, none of which came from the North Slope. If the total contracted amount of royalty gas (2.6 trillion cubic feet) were produced uniformly over a 20-year period, the annual volume of royalty gas would be 130 billion cubic feet. Thus, if all additions to intrastate natural gas consumption had to be drawn from the royalty gas in the contracts, then Alaskan gas consumption would have to triple over present levels before all the royalty gas would be withdrawn from the contracts.

Gas utility sales in Alaska grew at an average rate of 12.7% per annum from 1965 to 1975 and at a rate of 12.1% from 1974 to 1975. Total consumption of gas in Alaska rose from

TABLE IV-1NATURAL GAS CONSUMPTION IN ALASKA1975

<u>User</u>	<u>Sales by Gas Utilities Bcf</u> <u>1/</u>	<u>Total Consumption Bcf</u>
Residential	5.6	10.4
Commercial	6.4	8.5
Industrial	-	22.4
Electric Utilities	12.8	19.6
Other	5.9	5.9
Total	30.7	66.8

1/ Bcf = Billions of cubic feet

Sources: U.S. Bureau of Mines, Mineral Industry Surveys;
American Gas Association, Gas Facts 1975

42.0 Bcf in 1971 to 66.8 Bcf in 1975 or at an annual rate of 11.6%, as shown in Table IV-2. Growth of the natural gas industry has been from a fairly small base figure, so that a projection of recent rapid growth rates may be unrealistic, at least in areas already well served by gas. However, even if it is assumed that growth continues at the somewhat reduced rate of 6% per annum, Alaska's internal gas consumption would triple in about 18 years. If the slightly faster rate of growth of 10% occurs, consumption will triple in about 11 years. In either case, internal consumption would outstrip the annual volume of royalty gas before the end of the term of the 20-year contract. Moreover, the level of intrastate demand achieved by the end of the contract term could not be sustained by royalty gas from Prudhoe Bay beyond the productive life of that area. However, areas closer to Alaskan gas markets such as the lower Cook inlet may be the source of future growth in natural gas supply.

AMMONIA PRODUCTION

As a part of our economic analysis of the contracts for the sale of royalty gas, we have considered the possibility that Alaska might prefer to export manufactured products which use gas as a feedstock rather than exporting the natural gas itself. The principle argument would be that the value added (wages, salaries, profit) would thereby be retained for the Alaskan economy.

We considered, in particular, industries which are heavily dependent upon natural gas, such as ammonia manufacture. We determined that, if all of the Alaskan royalty gas were devoted to ammonia production, Alaska would then produce about 30% of the present U.S. level of ammonia output. Ammonia production in the U.S., although it is one of the most intensive industrial uses of natural gas, nevertheless consumes only a small fraction (a little over two percent) of total

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TABLE IV-2GROWTH OF NATURAL GAS CONSUMPTIONALASKA 1971-1975

<u>Use</u>	<u>1971</u> <u>Bcf</u> ^{1/}	<u>1975</u> <u>Bcf</u>	<u>Average Annual</u> <u>Rate of Growth</u>
Residential	6.9	10.4	10.3%
Commercial	7.5	8.5	3.1
Industrial	10.6	22.4	18.7
Electric Generation	10.3	19.6	16.1
Other	6.7	5.9	-3.2
Total	42.0	66.8	11.6%

^{1/} Bcf = Billions of cubic feet

Source: U.S. Bureau of Mines, Mineral Industry Surveys

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U.S. natural gas production. The U.S. ammonia market simply could not absorb such a large increment in supply.

Moreover, planned additions to ammonia capacity in the lower 48 states are already quite large, amounting to 3.2 million metric tons per year, or a 22% increase over present capacity. As shown in Table IV-3, principal U.S. markets for ammonia fertilizers are in the Midwest, an area more accessible to ammonia plants in Texas, Louisiana or Alberta than to ammonia plants in Alaska. European markets for nitrogen fertilizer probably could be served more economically from the Persian/Arabian Gulf, and thus may not be a prospective long-run market for ammonia from Alaska.

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TABLE IV-3UNITED STATES NITROGEN FERTILIZER CONSUMPTIONBY GEOGRAPHIC AREA1974(In 10⁶ Pounds)

	<u>Quantity</u>	<u>Percent of Total</u>
West Coast ^{1/}	1,301	7.8
Upper Midwest	10,096	60.8
Lower Midwest	3,111	18.8
Atlantic Seaboard	2,084	12.6
Total United States	16,592	100.0

^{1/} Includes Washington, Oregon, and California

Source: U.S. Department of Agriculture

This chapter comments on several specific details in the royalty gas contracts which appear to need clarification. Each point below is keyed to the section of the contract pertinent to the issue. We have suggested possible remedial actions in each case.

1. ARTICLE III (QUANTITY); SECTION 3.7(a):

This section refers to the terms under which the buyer may purchase additional quantities of surplus Alaskan royalty gas in the event that Alaska has previously implemented its option to remove contract gas for intrastate use. Section 3.7(a) continues to be applicable for a period of five years after expiration of the term of the contracts.

The governing price of surplus royalty gas offered to buyer after expiration of the contract and in the event of no other interstate bona fide purchasers is unclear. This section states only that,

"In the event there are no other interstate bona fide purchasers, the price shall be the price then being paid by Buyer for gas purchased under this Agreement."
(Underscoring inserted.)

Contract clarification of the applicable price is needed in the event deliveries have already been completed under the contract and no outside interstate purchasers exist.

2. ARTICLE VI (PRICE); SECTIONS 6.3 - 6.5:

Section 6.4 (deregulation after commencement of first gas deliveries) clearly provides for a price redetermination to occur as outlined in Section 6.5. Section 6.3, however, which provides for an initial price in the event of non-regulation existing at the time of first deliveries does not contain a price redetermination clause. Since Section 6.5 makes specific reference only to Section 6.4, it is unclear that price redetermination will also

occur in the event Section 6.3 is operative. Insertion of a clause in the contracts indicating that a price redetermination will occur in the event Section 6.3 applies is suggested.

3. ARTICLE VI (PRICE):

This Article of the contracts does not address a pricing situation in which the initial gas sales are not subject to F.P.C. regulation but, later in the contract term, become jurisdictional. Such a scenario could occur as a result of (1) judicial appeal of an initial F.P.C. ruling; (2) deregulation of gas prices conducted on a temporary or experimental basis, such as was proposed by President Carter during the election campaign; or (3) Federal action overriding the F.P.C. (e.g., creation of a general price and wage control policy).

TABLE 1F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.: 699

Date Issued: June 21, 1974

Definitions of
"new" gas:

- (1) Sales of natural gas in interstate commerce made from wells commenced on or after January 1, 1973.
- (2) Sales of natural gas in interstate commerce made pursuant to contracts executed on or after January 1, 1973 for
 - (a) gas not previously sold in interstate commerce (except under specified F.P.C. certificates); or
 - (b) where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973.

Applicable Rate: 42¢/Mcf with 1¢/annual escalation beginning January 1, 1974

F.P.C. Opinion No.: 699-H

Date Issued: December 4, 1974

Definitions of
"new" gas:

- (1) Sales of natural gas in interstate commerce from a well or wells commenced on or after January 1, 1973.
- (2) Sales made pursuant to contracts for the sale of natural gas in interstate commerce
 - (a) for gas not previously sold in interstate commerce prior to January 1, 1973 (except under specified F.P.C. certificates); or

16.45

TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

- (b) where such sales are initiated on or after January 1, 1973 provided the sale has not been certificated under the F.P.C.'s optional procedure.
- (3) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.
- (4) Gas produced from newly discovered reservoirs located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall have the rate determined by the date of reservoir discovery in lieu of the contract date.

Applicable Rate: 50¢/Mcf and 1¢/annual escalation beginning January 1, 1975

F.P.C. Opinion No.: 749

Date Issued: December 31, 1975

Definitions of "old" gas: Sales of natural gas in interstate commerce for resale from a well or wells commenced prior to January 1, 1973.

Applicable Rate: 23.5¢/Mcf prior to July 1, 1976; 29.5¢/Mcf on and after July 1, 1976. (This rate does not supercede existing higher area rates nor other specified F.P.C. established rates.)

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.: 770

Date Issued: July 27, 1976

Definitions of
"new" gas:

- (1) Sales of natural gas in interstate commerce for resale from a well or wells commenced on or after January 1, 1975.
- (2) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1975 (except under specified F.P.C. certificates), where the sale is initiated on or after January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure.

Applicable Rate: \$1.42/Mcf and 1¢/Mcf per quarter commencing October 1, 1976

Definitions of
1973-1974 gas:

- (1) Sales of natural gas in interstate commerce for resale made from a well or wells commenced on or after January 1, 1973 and on or before January 1, 1975.
- (2) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce on or after January 1, 1973 (except under specified F.P.C. certificates), where the sale is initiated before January 1, 1975.

Applicable Rate: \$1.01/Mcf

TABLE 1 (continued)

16-47

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.: 770-A

Date Issued: November 5, 1976

Definitions of
"new" gas: Sales of natural gas in interstate commerce
for resale from a well commenced on or
after January 1, 1975.

Applicable Rate: \$1.42/Mcf and 1¢/Mcf per quarter escalation
beginning October 1, 1976.

Definitions of
1973-1974 gas: Sales of natural gas in interstate commerce
for resale made from a well commenced on or
after January 1, 1973 and prior to January 1,
1975.

Applicable Rate: 93¢/Mcf and 1¢/Mcf annual escalation beginning
January 1, 1977

(NOTE: IN BOTH OF THE ABOVE DEFINITIONS, WELL DATE IS DEFINED AS
COMMENCEMENT OR SPUD-IN DATE REGARDLESS OF DATE OF
COMPLETION OR RECOMPLETION.)

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Exhibit 17

El Paso Alaska Company, et al)

Docket No. CP75-96, et al

REPORT TO THE COMMISSION

TO THE COMMISSION:

This is the second report to the Commission on the status of this proceeding. The schedule represented by the Commission to the Congress (attached to the first report dated January 21, 1976) called for the hearings to close by the end of May with an Initial Decision to be issued by September 1, 1976. While there has been some erosion of the schedule in recent weeks to the extent that it now appears that the hearings will continue through late June, it is not anticipated that this will cause the Initial Decision date to be extended. 1/ At this time, the applicants' cases in chief are completed; the key North Slope producers have submitted evidence both on Alaska exploration programs and reserve questions, and on corporate policy and regulatory matters; the answering cases of intervenors to applicants' presentations (except on environmental issues) have been heard; and examination of witnesses supporting the final environmental impact statement of the Department of the Interior is almost completed and that of the Environmental Task Force of the Federal Power Commission will commence next week. Except for the Department of State, which is now in the process of answering interrogatories prepared by the parties, all interested sister agencies and departments have appeared and presented witnesses on issues within their purview. It is anticipated that each interested agency having or intending to have a policy position will have stated it on the record before it closes.

1/ The slippage in the schedule has been caused principally by two factors: first, the inability of the Commission's Environmental Task Force to adhere to dates set for the submission of its evidence; secondly, the principal applicants have continued to modify and refine their applications necessitating the submission of additional evidence, e.g. Gas Arctic's switch to the McKenzie Delta route.

It is agreed by all active parties that specific placement of financing can only occur after the choice as to the successful applicant has been made. Nor can financing occur, as discussed at length in the prior report to the Commission and more fully below, without definitive sales agreements being in place so that the prospective equity holders (gas purchasers) can arrange financing on the basis of the reserves committed to them. Since the prior report in January, it has become evident both that (1) these contracts will not be entered into before the close of the hearing and (2) a condition subsequent in the certificate requiring that contractual commitments be filed after certification of a route is acceptable to all parties including the Commission's staff. It is expected that the additional time required to review these contracts, the financing plans, and other post-certificate requirements will occur contemporaneously and will be completed within a limited time. Expedient Commission approval of sales contracts, particularly if most of the terms are spelled out in the transportation certificate, notwithstanding the fact that the contracts are not yet filed, and of the financial arrangements would be expected, and the evidence shows that actual construction of a transportation system would not be delayed if subsequent Commission review were completed by the summer of 1977.

Turning to the substantive issues, there are two principal areas of concern which continue to require attention. These arise, as previously stated, primarily because of the difficulty in arranging financing when the pipeline equity holders are unknown and even if known, would not be able to guarantee either repayment of debt or project completion. [As already stated, financing of either transportation system is contingent, in the first instance, upon producer sales contracts being in place so that prospective equity holders can seek firm commitments from the financial community. The key producers' witnesses on questions of corporate policy have unanimously declined thus far,

however, to give categorical present assurances with respect either to the time frame for execution of sales contracts or for deliveries of gas volumes. While their general attitude as to ultimate sales of their gas reserves is positive, their guarded position at this time is a reflection of their expressed concern respecting certain unsettled aspects of regulatory activities both on the part of the Commission and the Congress (Volumes 122 - 127). Specifically, they individually voiced their dislike of certain recent Commission regulations, some now under review, rejecting certain advance payment agreements and requiring possible application to Alaska natural gas of (1) minimum delivery obligations in producer certificates, (2) abandonment applications stemming from operations arising solely under field unitization agreements, and (3) disclosure by the Commission to their competitors of what they consider proprietary information. Further, they expressed distress that the Commission has not yet embarked upon a proceeding to establish a price for the gas and feared that an early sales contract would lock them into an adverse "cut-off" date either under possible vintage-pricing by the Commission or the possibility of a deregulation statute being enacted by Congress. From a technical point of view, they are apprehensive about selling gas prior to the approval of the unitization and production agreement which is unlikely to be effective prior to the end of 1976. 1/

None of the above-described concerns is based upon a legal inability to enter into sales contracts; they reflect basic policy considerations. Nor can most of the impediments suggested by the producer witnesses for justifying their reluctance to enter into sales contracts upon issuance of a conditional transportation certificate be resolved solely within the four corners of the present proceeding. Only Congress, for example, if it should choose to deregulate natural gas, is empowered to determine in the first instance whether and how it might apply to existing North Slope gas sales contracts. The conditions which are being

1/ Those producers' witnesses asked essentially supported the concept of the nationwide new gas rate applying to Alaska.

17.3

explored at this time, however, are designed to ensure that the producers enter into such contracts close upon the issuance of the transportation certificate by the Commission. The public interest clearly requires such agreements and it is fully anticipated that the climate will exist, based in part upon review of the producers' positions now displayed on the record, where the producers will be induced to enter voluntarily into timely definitive sales agreements.

The second area of concern is that the financing also cannot occur even if the equity owners are known absent both guarantees of project completion and repayment of the debt. The prospective pipeline equity owners for various reasons would not give these guarantees. Several suggestions requiring Commission approval of cost-of-service tariffs with "all events" provisos, which would have the effect of consumer guarantees to bond holders, have been advanced. Other suggestions have been made that additional credit worthy parties, such as the producers, could be induced to participate as either equity or debt holders. The producers have not as yet warmed up to this suggestion. Various forms of public participation have been suggested, but these are not held out as likely. In fact, the witnesses for the Department of the Treasury indicated that if the private sector was leery of what appeared to Treasury to be a reasonable and attractive certificate, Treasury would be unlikely to recommend committing public money to a venture rejected for business reasons by the private sector. One proposal which is now being briefed by the parties was advanced by El Paso and would permit interstate pipeline purchasers to modify their individual tariffs so as to provide, in effect, for direct consumer guarantee of debt financing. The various state public utilities commissions previously were invited to give their views as to certain tariff questions and the parties have been requested to serve upon them all trial briefs on tariff matters. 1/

1/ Numbers of responses were received and were copied into the record (Vol. 120, Tr. 19,184 et seq.; Vol. 125, Tr. 19,753).

17.4

A tentative briefing schedule has been adopted although no specific dates have yet been set. Trial briefs on tariff matters by some of the parties are expected this week. Briefs by applicants setting forth the full applications with suggested certificate conditions for implementation will be due about mid-May. Briefs by all parties on the environmental aspects will be due soon after the completion of that aspect of the case. Briefs on all remaining issues will not be due until after the close of the hearing.

As before, the discussion of these procedural and substantive issues is not intended to reflect the complete posture of the record or proceeding, but should serve to highlight the present problems and how they are developing on the record.

Respectfully submitted this 27th day of April 1976.

Nahum Litt

Nahum Litt

Presiding Administrative Law Judge

Copy to all Parties

Copies to all State Utilities Commissions

12:30 - 1775 K St. - 3rd Fl.

Rm 310

TO: Senator Radar

DATE: February 4, 1977

FROM: Jerry McCutcheon

Exhibit 18

I would like to add to my remarks of yesterday. When we discussed gas prices, I failed to mention the Donovan Shales, that underlie the Appalachian mountains. These shales and other type formations contain 2 quadrillion cubic feet, of which 500 trillion is expected to be recoverable. This is more than twice the proven reserves of the United States. It is expected that the gas can be produced for \$3.50 per MCF, which is substantially less than for what Alaska's gas can be delivered.

The El Paso system: During these hearings the El Paso system has been alleged to be able to operate on a volume as low as 2 BCFD. I believe the minimum filing for El Paso is 2.4 BCFD. However, the BLM study calls for 2.5 BCFD rising to 3.5 BCFD which is with a \$7 or \$8 billion line, which BLM admits is not possible. The gas system will cost \$14 to \$16 billion and this is admitted by the State Administration. The requirements for the El Paso system far exceed the ability of the Prudhoe Bay reservoir and can only be met at a totally unnecessary sacrifice of oil.

OMAR and the Chamber of Commerce brought to Alaska a Washington gas expert, Mr. John Camp. He is with a lobbying firm which represents the state of Louisiana in Washington for the purpose of trying to keep some gas in Louisiana. Mr. Camp sharply disagreed with OMAR stating that the State of Alaska should keep its gas in the ground and not become involved with an interstate pipeline.

Mr. Camp added that there is no way, regardless of how much money you spend for studies, that one can project the future growth and demand for in-state gas use. No matter what you project it is always severely underestimated, just as it was done in Louisiana and other states.

I do not believe there will be any further consideration of any gas line system if the State of Alaska will just tell the truth with respect to the reservoir producibility, cost of the gas system, the cost of the delivered gas, decreased demand caused by the higher prices, and the availability of cheaper alternatives.

It is only through practiced dishonesty by the State of Alaska and its representatives that the consideration of the gas line systems is being kept alive.

VINSON, ELKINS, SEARLS, CONNALLY & SMITH

ATTORNEYS AT LAW

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January 28, 1977

Exhibit 19

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House Special Committee and
Senate Special Committee to
Consider the Sale of Royalty Gas
The Legislature of the State of Alaska
State Capitol
Juneau, Alaska 99811

Gentlemen:

You have requested my review and analysis of the contracts by and between the Commissioner of Natural Resources of the State of Alaska acting pursuant to AS 38.05-.183(d), seller, and Tenneco Alaskan, Inc., El Paso Natural Gas Company and Southern Natural Gas Company, buyers. The contracts in question are each in two parts, one part denominated "General Terms and Conditions," and the other denominated "Royalty Gas Sales Agreement."

I express no opinion on matters relating to title, taxes, or compliance with State contracting requirements. My opinions here offered are limited, as requested, to a legal analysis of the contracts, and an assessment of the merits, and demerits, of the various provisions thereof.

To submit my opinions in these areas, I have reviewed the contracts in question, and a summary of Commissioner Martin's negotiations as furnished to me by the Office of the Attorney General of the State of Alaska. I believe these materials to be sufficient to render the requested analysis, but my comments are necessarily limited to the materials which were available to me for review.

I wish to make clear also that I do not arrogate to myself the formulation or expression of an opinion as to whether the contracts in question should, or should not, be approved by the Legislature. The vote of each member must necessarily be cast in terms of his own appraisal of the contracts, giving due and

19.1

appropriate regard to the constituency which he represents, their wishes and best interests, and his perception of where the interests of the State lie. It would be most presumptuous for me to offer an opinion on a matter so peculiarly within the responsibility of elected representatives, particularly when my exposure to the people, the economy and the planning of the State of Alaska is as limited as it is.

Finally, it must be clearly recognized that an analysis of contracts already negotiated, and an appraisal of whether those contracts are, on balance, "good" or "bad," if undertaken as an abstract proposition, can be most misleading and unfair to the negotiators. A contract takes shape through a process of bargaining, and many provisions may not be precisely as one of the contracting parties would wish. The provisions are forged through negotiation and compromise, and if one gauges the contract only by reading the final contract after the negotiation process has run its course, it might appear that certain agreements have been embodied in the contract which are less than desirable and which should be modified or eliminated. Were one familiar with the negotiation process, however, he might realize that the apparently undesirable provisions were in fact necessary if an agreement was to be reached. I would caution, therefore, against an interpretation of my comments and opinions as critical of the officials who negotiated on behalf of the State.

Having offered these preliminary explanatory comments, let me turn to the contracts themselves.

I append, as Attachment A, a detailed summary of the contracts, section by section. Rather than reiterate this summary, I would prefer to offer my generalized perception of the relative merits and demerits of the contracts in terms of probable benefits and areas of concern. The Committee may wish to explore the concerns which I set forth with the Commissioner of the Department of Natural Resources, for indeed his experience in the negotiation process may well substantiate the view that the contracts as presented to the Legislature, even though containing certain problem areas, do in fact represent the best bargain that could have been struck under all of the attendant circumstances.

* * * * *

I would speak first on a positive note, addressing the obvious benefits which accrue to the State under the contracts as submitted to the Legislature for approval. I suggest that the benefits are material and substantial and, specifically, there are the following factors to be considered:

1.

The State has secured an agreement for full reimbursement of all costs related to the State's taking of its gas in kind. (Article II, Sections 2.2 and 2.3.) I consider this to be a significant concession in behalf of the State. When the State takes its gas in kind, it is quite possible that the taking will occur at the point of production, so that all costs incurred downstream from that point, such as for transportation to a processing plant, processing, and redelivery to a pipeline transporter, must be borne by the State in ratio to its percentage of the production taken. I do not believe that anyone can guarantee that the State would not be exposed to claims for substantial costs resulting from the in-kind taking. The royalty sales agreement clearly insulates the State from cost exposure with respect to the initial arrangements necessary to an in-kind taking, whether or not the costs reimbursed to the State by the buyers of the royalty gas are collectable by the buyers in their jurisdictional resale rate structure.

2.

The State has sold only a portion of its Prudhoe Bay royalty gas, and has secured the contractual right to withdraw volumes sold under the contract for Alaska in-state needs. (Article III, Sections 3.1 through 3.6.) If an alternate market for the State's royalty gas develops between the present time and the time when the buyers under the contract are in a position to take delivery, the State may take and dispose of its royalty gas in any manner that it chooses, so long as such taking and/or disposition does not interfere with the State's ability to deliver to the buyers when they are in a position to take. (Section 3.8.) The State is not committed by contract to a warranted volume of gas to be sold and delivered under the contracts, and has no stated minimum delivery obligation. (Section 3.2.)

I consider these provisions to be extremely favorable to the State. It is prudent to retain a portion of the State's royalty gas even when a decision has been made to sell part of that royalty gas, since holding a portion free of commitment permits negotiation at a later time when operating conditions have been established, and when circumstances may indicate that significantly different contractual arrangements are in order. Thus, sale of 2.6 Tcf under the contracts in question, rather than a sale of all of the State's Prudhoe Bay royalty gas is, in my judgment, proper.

It has, of course, been essential from the outset that the future needs of the State for natural gas for in-state uses must be in some manner accommodated throughout a royalty gas sales arrangement. It would obviously be unacceptable for the State to sell its royalty gas for transportation out of the State without some provision for meeting future natural gas needs within the State. The arrangement worked out in the contracts to accomplish this objective is favorable to the State. The State may withdraw, over time and upon suitable notice, up to 100 percent of the gas contracted for sale under the instant agreements; the rights of withdrawal must, of course, be exercised for the sole purpose of the State meeting the intrastate domestic and industrial needs of the State of Alaska, and the withdrawal is scaled from 25 percent through 100 percent over 20 years; nonetheless, the withdrawal provisions are more favorable than I would have anticipated and they represent a major element of strength in these contracts.

3.

The State has excepted and reserved from the sale, all liquids removed from the State's royalty gas prior to its delivery to the pipeline (Article IV, Section 4.4), and the State has retained processing rights for the recovery of liquefiable hydrocarbons other than methane, whether exercised before or after delivery to the buyer. (Article IX.) If the liquids are not removed from the gas stream so that the liquid content of the gas stream delivered for sale produces a higher than 1,000 Btu per cubic foot average, the State will be compensated for the greater heating content through adjustment of the sales price. (Article VI, Section 6.6.)

These arrangements for the State to retain the benefits of the liquid content of the gas stream should prove beneficial to the State over the life of gas production from Prudhoe Bay. Liquids and liquid products can provide a significant source of additional revenue to the State if they are sold on the open market and, conversely, if there is need for liquid products in the State (such as a need for propane for its multiple uses, or a need for butane and natural gasoline as feedstocks for petrochemical or other operations), the State is free to direct the liquids and the liquid products to their highest and best use. The inclusion of these provisions in the contract is a distinct plus.

4.

The contract permits State withdrawal from the contract, without penalty, in the event of the occurrence of several different circumstances: If the State is prevented from taking its gas in kind by federal action, the sales agreements shall be void (Article II, Section 2.1); the contracts can be terminated if a decline in production results in nonprofitability to the State (Article VIII); the sales agreements may be terminated by the State if the State so elects following Federal Power Commission certification of an Alaskan gas transportation proposal, except that this right of termination would not exist if the Commission's grant of a certificate is to the El Paso project (Article XI, Section 11.5); and the State may terminate the royalty sales contracts if, by January 1, 1979, all regulatory approvals which the State deems necessary to enable the State to perform its obligations under or receive the benefits of the contract have not been received (Article XI, Section 11.2).

The cumulative effect of these termination options is sufficient, in my opinion, to safeguard the State against reasonably foreseeable adverse developments which might occur. Their inclusion in the contracts is of significant value to the State.

* * * * *

I must now turn to certain aspects of the contracts which are of concern to me. These relate to the pricing of the State's royalty gas when sold to the buyers under these contracts.

19.5

1. Section 6.1 imposes an upper limit on the price which the state will receive for its royalty gas, and this limitation will be operative unless and until appropriate Federal legislation deregulating Alaska gas is passed. The Section 6.1 limitation, in full, is as follows:

"In consideration thereof, the price which buyer shall pay seller for gas purchased hereunder shall be determined in accordance with Section 6.2 or Section 6.3 or Section 6.4 or Section 6.5 and shall be subject to the adjustment as provided in Section 6.6; however, the price paid seller for gas which buyer reflects in its rates to jurisdictional customers shall never be higher than the price buyer is permitted to retain in its jurisdictional resale rates so long as such rates are subject to regulation by the Federal Power Commission (or any successor governmental authority having jurisdiction in the premises)."

The underscored proviso is thus given controlling affect, irrespective of the price indicated under Section 6.2 (price fixed at the highest price permitted by the Federal Power Commission to any working interest seller from the Exhibit A reservoirs); irrespective of the price indicated under Section 6.3 (in the event of deregulation at the time of first deliveries, the price is fixed at the level of the highest price being paid by any interstate gas purchaser for gas produced from the Exhibit A leases); irrespective of the price indicated under Section 6.4 (in the event of the cessation of federal regulation after such has once commenced, the price is to be fixed by redetermination and/or arbitration); and irrespective of the price which would result from redetermination in accordance with Section 6.5

The limitation holds as a ceiling on the State's sale price "so long as such rates (buyer's jurisdictional resale rates) are subject to regulation by the Federal Power Commission"

It is inescapable that the buyers under these contracts will become transporters of natural gas in interstate commerce, and that they are purchasing gas for resale in interstate commerce. The rates at which the buyers sell for resale will be within the jurisdiction of the Federal Power Commission under the Natural Gas Act, and I know of no foreseeable set of circumstances that would produce legislation, or a Commission decision, changing this result.

Section 6.1 may not be unduly burdensome if legislation is passed which denies the Federal Power Commission the power to refuse recovery of purchased gas costs in an interstate transporter's jurisdictional resale rates, for then it could be argued that the buyers under this contract must necessarily be "permitted to retain" in their jurisdictional resale rates the amounts paid to the State and, therefore, the ceiling limitation in the Section 6.1 proviso would not interfere with operation of the other pricing alternates in the contracts. Such legislative language was employed in the bill which passed the United States