SCOMM

28:12

TO: John McMillian
President
Northwest Alaska Pipeline Company

Dear John:

We look forward to receiving your lease or permit application which will forward our joint goal of an early and successful completion of the Alaska Natural Gas Transportation System.

We know that you now understand the dilemma the application has posed for us. If the AGCF were in fact part of the Alaska Natural Gas Transportation System, it would be appropriate for the State to issue the lease under the pipeline right of way leasing statute. If it is not part of the system, a site lease would be the appropriate vehicle and that would be granted under different provisions of the Alaska statutes. We realize the answer to this question is inextricably related to resolution of the financing questions.

Also, our Washington counsel has informed us that an application by Northwest as operator under the D & E Board in the form proposed raises substantial questions whether it is beyond the authority given the stated purpose and duration of the Design and Engineering Board. Mr. McKay has informed us of your intention to assign the lease, if awarded to Northwest, to a successor entity to avoid this problem. We appreciate that the application in its present form is a compromise vehicle pending the resolution of questions of financing and inclusion of the plant within the system.

It must also be noted that, whichever way we proceed, the application must be processed under the existing procedures of the Alaska statutes and the regulations of the Department of Natural Resources [redacted]. Completing those procedures takes substantial time.

We propose that Northwest may proceed with its interest in a site lease for the AGCF. That site lease, under Alaska law, must be issued under the competitive procedures. We are particularly interested in your legal opinion that your application should fall under AS 38.05 rather than AS 38.35, which the State believes to be the determining law. However, given the issues that have been identified, the State feels that certain conditions subsequent or termination conditions should appropriately be included in the grant of any lease for the AGCF. Our present thinking is that the following conditions may be appropriate:

1. The lease would terminate absent the completion of a successful financing plan in 1981;

2. The lease would terminate if the project terminates;

3. The lease would terminate absent a determination that an appropriate share of conditioning costs are borne by

the transportation system. As we have indicated, the issue of conditioning cost responsibility is inextricably related to the successful financing of the Alaska Natural Gas Transportation System and, therefore, we expect that it will be resolved as part of the financing negotiations. At present, we think that an appropriate share would be the assumption of all of the conditioning costs by the transportation system, but we remain open to persuasion that some other sharing of the conditioning costs is proper and necessary to arrange a successful financing.

4. We reserve the right to impose other conditions, but the decision to increase any conditions, as well as their precise formulation, would occur during the procedure for issuing the competitive lease. One question that remains outstanding, for example, is the satisfaction of the State's concerns with respect to socio-economic costs created by both the pipeline and the conditioning plant.

We repeat our intention not to delay the project and we reiterate our offer to proceed with special land use permits to permit those activities that must be conducted this spring and summer. We also repeat our intention to abide by State procedures in granting a lease under the appropriate statute. Finally, I must emphasize that we are all aware of the state of progress with respect to ANGTS. It is for that reason that we insist that the State not be singled out for causing a year's delay in the scheduled completion date of the system when we all know that there are many causes for such delay if it should occur.

Sincerely,

Jay S. Hammond
Governor
State of Alaska

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

re: Dow-Shell Petrochemical Feasibility Study 9/5/80

COMMISSIONER'S FINDINGS

Under the authority invested through AS 38.05.020(b)(2), the Commissioner of Natural Resources may enter into agreements he considers necessary to carry out the purposes of the Public Lands chapter. In September , 1980, and after an extensive public process to be described hereinafter, the State of Alaska, acting through its Commissioner of Natural Resources, and Dow Chemical U.S.A. and/or Shell Chemical Company, together with "Participants" Alaska Interstate Company, Asahi-Dow, Ltd., Doyon, Ltd., E.I. duPont de Nemours, Earth Resources Company of Alaska, Mitsubishi Chemical Industries, Ltd. and Mitsubishi Corporation, and "Affiliate" Alaska Interior Resources Company will enter a Memorandum of Understanding and Intent. All the companies together, operating as the Dow-Shell Group (DSG), agreed to take certain actions toward the ultimate goal of establishing, if feasible, an in-state industry using natural gas liquids from Prudhoe Bay. A copy of the agreement is attached

The State has demonstrated a long term interest in maintaining options and improving opportunities for future petrochemical manufacturing in Alaska. The State's Prudhoe Bay oil and gas leases require that one-eighth of all oil and gas produced under lease be granted to the State as royalty. As a matter of both law and policy, the State's foremost priority is that its royalty hydrocarbons be processed inside the State and that the products be distributed first within the State before product or raw material export takes place. Prudhoe Bay gas production is scheduled to commence within the next decade, probably by 1986. Approximately 2 billion cubic feet per day of sales gas will be produced for the 2-to-25 year life of the field, with the State's royalty share averaging 250 million cubic feet per day. On this date, no disposition of the State's royalty gas (methane) or royalty gas liquids, including ethane, from the Prudhoe Bay field unit, remains in effect.

The State has long supported making natural gas liquids available as feedstock for petrochemical manufacturing in Alaska. The State's attorneys, for example, have attempted to keep petrochemical development options open during the ongoing Federal Energy Regulatory Commission (FERC) hearings on gas pipeline issues. The State has consistently argued, in addition, that piecemeal disposition of the issues affecting availability of natural gas liquids is counterproductive and that the pipeline pressure issue should have been considered simultaneously with the issues of CO2 level and butane disposal.

On August 6, 1979, FERC issued its Order Approving Alaska Segment Design Specifications and Initial System Capacity.

In response to widespread concern about the implications of FERC's action, the Governor appointed a Working Group on Natural Gas Conditioning, with membership from the Administration, the Legislature and the municipalities. After a series of meetings in August and September at which the group identified issues surrounding instate use of royalty gas and royalty gas liquids, and development of an instate petrochemical industry, the Governor's Working Group resolved the following at its September 21 meeting: (1) the subcommittee's reports, as approved by the full Working Group, be transmitted to the Governor as the preliminary report; (2) the Governor be requested to determine the present day feasibility of an instate petrochemical industry, particularly by actively contacting and soliciting the interest of major petrochemical companies with regard to the feasibility of such development; and (3) the Governor be requested to preserve the State's options by requesting the FERC to re-open for hearing the project's size and pressure issue and, failing that, filing an appeal of the FERC size and pressure order in federal court no later than October 5, 1979. The Working Group's September 21 resolution was accompanied by another asking the Governor to continue the Working Group by allowing its members to serve as ex officio members of the Legislature's Joint Gas Pipeline Committee.

The Administration responded to the recommendations of the Governor's Working Group by authorizing the State's attorneys to file suit in U. S. District Court to overturn the FERC size and pressure order issued August 6. In addition, in late October and early November, 1979, Administration representatives and members of the Legislature met with North Slope gas producers, petrochemical firms, Northwest's investment advisors, congressional members and federal agency representatives to discuss the gas pipeline project and potential petrochemical development.

FERC public hearings on the Draft Environmental Impact Statement for the Prudhoe Bay project gave Alaska citizens and officials the opportunity to comment publicly on September 4 and 5, 1979, on the petrochemical development issues, such as location of the gas conditioning plant and availability of natural gas liquids. At issue were the conclusions and much of the content of FERC's Draft Environmental Impact Statement released July 27, 1979.

At the November 21, 1979 meeting of the Legislature's Joint Gas Pipeline Committee, Attorney General Avrum Gross announced the State's intention to seek formal proposals for petrochemical development. The Committee, with the Governor's Working Group, endorsed a resolution concerning Alaska's securing gas liquids for use in an Alaska petrochemical industry, and also endorsed a proposed schedule for further administrative action for acquisition and delivery of gas liquids and development of a related industry. Copies are attached.

The four Alaska mayors also reiterated their position on potential petrochemical development and State participation in the gas pipeline project. First, they supported maximum instate use of gas liquids. Second, they believed acquisition of liquids is the only basis for state financing of the gas pipeline. And, third, they urged the State to take the lead in purchasing negotiations of the producers' liquids.

In response, the Administration continued its conversations with producers concerning the possibility of an option to purchase, or an outright purchase, of all or a part of the producers' processing rights to Prudhoe Bay gas. By June of 1980, the State had received formal replies from the three major Prudhoe Bay gas producers (Exxon, Atlantic Richfield, and Sohio-BP), which indicated their willingness, under certain conditions, to enter into good faith negotiations with a financially responsible major petrochemical concern sponsored by the State of Alaska (copies attached). Exxon Chemical Company later indicated its intention of completing a major feasibility study to determine the economics of a gas based petrochemical industry in Alaska.

In January, 1980, Governor Hammond reconstituted the working group as the Alaska Natural Gas Task Force. Lt. Governor Terry Miller was named to chair the Task Force whose membership included the Commissioners of Revenue, Natural Resources, and Commerce, the Attorney General, four legislators and five mayors. At that time the State anticipated that the Phase I Letter of Intent for the Northwest Gas Pipeline Project would be signed by the Northwest partnership and the producers by February 1.

The role of the Task Force was to evaluate and monitor the developing plans for the Phase I design of the gas pipeline, particularly with respect to its impact on potential development of instate petrochemical facilities. Negotiations for the Phase I Letter of Intent, however, were slower than originally anticipated, with the parties signing the document on June 20, 1980. Accordingly, the role of the Governor's Task Force became focused on the State's solicitations for gas liquids development and selection of a company or companies to receive the State's backing for a feasibility study of petrochemical development.

On February 4, 1980, the Governor issued a "Solicitation of Interest" to more than seven hundred firms potentialy interested in development projects using Prudhoe Bay gas liquids. Firms were to respond to the initial solicitation by February 15; the deadline was later extended to March 30 at the request of several companies.

Spring, 1980, activities included the approval by the Joint Gas Pipeline Committee of a proposed FY 81 budget for studies and continued activities relating to the gas pipeline and petrochemical development. Administrative and legislative support was given to inclusion to the proposed funding in the State budget.

The Governor's Natural Gas Task Force continued its meetings, receiving updates on the Washington, D. C. gas pipeline project negotiations, firms' responses to the solicitation of interest, and proposed budget. In March, 1980, I issued a "Further Solicitation" to the firms that responded affirmatively to the initial solicitation.

In June, 1980, the State received several formal proposals in response to its "Solicitation" and "Further Solication." The firms and individual responding included Alaska Arctic Resources Group; Dow/Asahi-Dow, with Shell Petroleum; Earth Resources/Mitsubishi; Nissho-Iwai Group; Phillips Petroleum; Alaska Interior Resources; and Jerry McCutcheon. Exxon Chemical Company also indicated its intention of conducting its own independent examination of the feasibility of an Alaska petrochemical industry.

On July 18 and 19, 1980, the petrochemical firms made public presentations to the Governor's Task Force on their formal proposals. The public presentations were followed on August 7 by public hearings on the proposals in Fairbanks and Anchorage. Following the public hearings, a subcommittee of the Task Force (Lt. Governor Terry Miller, Commissioner LeResche, and Mayor Carlson) entered into initial negotiations with the petrochemical groups. At an August 15, 1980 meeting of the Task Force, the group moved to continue negotiations with three of the proposers: Dow/Shell; Alaska Arctic Resources Group; and Phillips Petroleum. Further negotiations the week of August 18-25 led to Phillips Petroleum withdrawing from the selection process and negotiated "Letters of Understanding and Intent" drawn up between the State and the Dow/Shell Group, and the State and Alaska Arctic Resources. The Governor's Task Force met again on August 28 to review the proposed Letters of Intent and to again consider the basic proposals, and at that time, decided to recommend Dow/Shell to the Governor as the group the Task Force recommends to complete a feasibility study of an instate gas-based petrochemical industry.

PURPOSE AND FINDINGS

The purpose of the memorandum of understanding and intent is to facilitate the wise development of Alaska's royalty gas liquids by providing means and procedures calculated to promote private economic growth consistent with applicable environmental standards and public fiscal stability. Alaska statutes provide that, at an appropriate time, the State will take, if possible, its royalty gas liquids in kind rather than in value. Alaska statute further provides that the sale of royalty hydrocarbons be by competitive bid except when the Commissioner determines that the best interest of the State does not require it.

Certain unknowns make it impossible to prudently dispose of the State's Prudhoe Bay royalty gas and royalty gas liquids at this time. These unknowns include: the yet undetermined value of the gas liquids; the uncertain econcomic feasibility of a gas-based petrochemical industry in Alaska; the financial and operational impacts, if any, of gas-based petrochemical development on the gas pipeline project; the impacts, such as field fuel requirements and line routing requirements, of gas-based petrochemical development on the TAPS line; timing of gas sales and delivery through the gas pipeline; and ownership and operation/management of the Prudhoe Bay gas conditioning plant.

At the same time, however, that many unknowns make final disposition of the State's Prudhoe Bay royalty liquids unwise at this time, other factors make it vital that the State take decisive actions to maintain the possibility and maximizing the probability of future gas-based petrochemical development. The Phase I agreement between the producers and the Northwest Pipeline sponsors has provided the gas pipeline project with a significant step toward a speedier completion of pipeline engineering and design. A bid package for a contractor to prepare the Phase I design work has been prepared and distributed to bidders. The signing of the contract and initiation of design work for the gas pipeline, including the gas conditioning plant, is scheduled for October 1, 1980. Selection of a gas conditioning process is set for February 1, 1981, with bids prepared for major equipment purchases by June 1, 1981. In other words, the timeline for the natural gas pipeline project has been set; the decisions made within the next few months will have a determinative effect on the options of a gas-based petrochemical industry.

Industry representatives and others examining the potential for petrochemical development in Alaska have often stated that project economics may demand that the entire volume of Prudhoe Bay natural gas liquids be available for use in the project. Securing a sufficient quantity of natural gas liquids, obtaining needed design changes on the gas conditioning plant to maximize liquids recovery, and obtaining design changes, if needed,on the gas pipeline itself will all require cooperative efforts by the producers, the Northwest partnership, the petrochemical firms and the State. Coordination of potential petrochemical development with gas pipeline and gas conditioning plant design, construction and operation is vital to resolving satisfactorily the issues of field fuel options, conditioning plant location, conditioning plant design, pipeline pressure and pipeline CO2 level. Linking the petrochemical feasibility studies with the on-going gas pipeline design work thus becomes a crucial factor in protecting the opportunities for instate petrochemical development.

A second major crucial factor is the ability of the petrochemical firms to negotiate with the producers to acquire producers' liquids, as there is common agreement that the State's royalty gas liquids alone are not sufficient feedstock for an economically sound petrochemical venture. The short critical timetable and the need for close cooperation and/or negotiations with the gas producers led the Task Force and myself to making a decision to recommend only one company to continue with a petrochemical feasibility study. The DSG has agreed to immediately negotiate contracts(s) with North Slope producers for the purchase of natural gas liquids. It has also agreed to provide appropriate engineering expertise to the State during the conditioning plant and gas pipeline design process, and to the State's contractor for the liquids pipeline design/cost study. In addition, DSG has specifically committed to providing an analysis of the Selexsol gas conditioning process and the Sulfinol gas conditioning process during conditioning process during conditioning plant design.

Another factor in the decision to select only one company rather than to continue working with two or more companies was the position taken by the firms. The Alaska Arctic Resources Group stated that it would not be willing to continue its work in this area if more than one company were selected; the DSG maintained that it would continue, but on a reduced basis, its efforts at examining instate petrochemical feasibility, were more than are group chosen. The selection of only one group to continue with a petrochemical feasibility study, however, does not bind the State in any way to ultimately negotiate a royalty liquids sales agreement with that group. As is explicitly stated in the Memorandum of Understanding and Intent, the State reserves the right to determine after the submittal of the feasibility study if the DSG project is in the State's best interest and if the State's royalty gas liquids should be sold to DSG. The Memorandum also cites provisions which would be included in any sales agreement for the State's royalty gas liquids, including pricing and instate use provisions. The memorandum also emphasizes that the State reserves the right to act in its best interests, require due diligence from DSG and prohibit DSG from assigning the memorandum without first obtaining the written consent of the State.

In making a final determination as to whether to negotiate a royalty gas liquids sales agreement between the State and DSG, I must consider the criteria cited in AS 38.06.070: the basic economic feasibility of the project; the revenue needs and projected fiscal condition of the State; the existence and extent of present and projected local and regional needs for gas products and by-products; the desirability of localized capital investment; increased payroll, secondary development and other possible effects of the sale, exchange or other disposition of royalty gas liquids; the projected social impacts; the projected additional costs and responsibilities which could be imposed upon the State and affected political subdivisions by the project; the projected positive and negative environmental effects; the projected effects of the project upon existing private commercial enterprise and patterns of investments; and the potential processing and sale of products instate. This consideration cannot be competently made without facts that will become available during the next 12-18 months, as a result of the feasiblity study, state studies, and work done by and decisions made by the Design and Engineering (Phase I) Board, the pipeline partnership, and the producers.

Robert E. LeResche

Commissioner

5 September 1980

Date

re: Dow-Shell Petrochemical Feasibility Study 9/10/80

MEMORANDUM OF UNDERSTANDING AND INTENT

The State of Alaska (referred to in this memorandum as "State"), acting through its Commissioner of Natural Resources, pursuant to AS 38.05.020(a)(2), and Dow Chemical U.S.A. and/or Shell Chemical Company (a division of Shell Oil Company) as Sponsors ("Sponsors") and Alaska Interstate Company, Asahi-Dow, Ltd., Doyon, Ltd., E. I. duPont de Nemours, Earth Resources Company of Alaska, Mitsubishi Chemical Industries, Ltd. and Mitsubishi Corporation as Participants ("Participants"), and Alaska Interior Resources Company, Inc. as an Affiliate ("Affiliate"), all companies together operating as the Dow-Shell Group ("Dow-Shell Group"), agree to take certain actions toward the ultimate goal of establishing, if feasible, an in-state industry utilizing natural gas liquids from Prudhoe Bay. Nothing in this memorandum should be construed to require the Dow-Shell Group to establish such an industry or the State to sell royalty gas liquids to the Dow-Shell Group. Each party is required to take only the actions enumerated in this memorandum.

DOW-SHELL GROUP

1. Parties.

The State and the Dow-Shell Group understand that while the Participants and Affiliate may undertake certain responsibilities pursuant to the terms of this memorandum, the full and complete responsibility for performance hereunder shall be undertaken by the Sponsors. Further, solely for the assistance of clarifying the anticipated responsibility roles of the companies comprising the Dow-Shell Group, the following is an identification of the roles of each company in the Dow-Shell Group.

2. Sponsors.

Dow Chemical U.S.A. and Shell Chemical Company are joint sponsors of and have overall responsibility for the feasibility study phase hereinafter described, including insuring that the study is completely integrated and every study responsibility is covered. For administrative and communications purposes, Dow is considered the project "leader" throughout the feasibility study. Dow and/or Shell will be the parties who would ultimately enter into an agreement with the State and Producers to purchase natural gas liquids. Dow and/or Shell would own and operate ethylene and derivatives plants in Alaska.

3. Participants.

The following companies will participate in the feasibility Study with a view to assuming the responsibilities outlined below:

(a) Alaska Interstate Company would own and operate the NGL pipeline from Fairbanks to tidewater.

(b) Asahi-Dow Ltd. would participate in derivatives plants utilizing feedstock produced by the sponsors.

(c) Doyon, Ltd. would own and operate the NGL pipeline from Prudhoe Bay to Fairbanks.

(d) E. I. duPont de Nemours would participate in derivatives plants utilizing feedstock produced by the sponsors.

(e) Earth Resources Company of Alaska would expand its North Pole refinery and would supply aromatics to chemical plants in Alaska operated by others in the group.

(f) Mitsubishi Chemical Industries, Ltd. and Mitsubishi Corporation would participate in derivatives plants utilizing feedstock produced by the sponsors.

4. Affiliate.

The following company will contribute to the Feasibility Study in the manner indicated below:

Alaska Interior Resources Company, Inc., (AIRCO), with the cooperation of Dow Chemical U.S.A., would study the feasibility of providing coal-fired electric power to the petrochemical project and would study the feasibility of constructing a coal-based methanol plant in Interior Alaska. In addition, in a separate proposal, AIRCO would study the feasibility of a methanol facility located in Interior Alaska utilizing methane as feedstock.

RESPONSIBILITIES OF THE DOW-SHELL GROUP

5. Feasibility Study.

Sponsors will complete and submit to the State a Feasibility Study for the manufacture of petrochemicals in Alaska within twelve months of the time the Governor officially designates Sponsors as the only party to proceed. The Study shall be of such quality as to justify an irrevocable investment decision. The Study shall include everything covered by the Dow, Shell, and Earth Resources-Mitsubishi proposals submitted to the State in writing on June 16, 1980 and verbally presented to the Natural Gas Task Force on July 18 and 19, 1980, including but not limited to:

(a) Economic feasibility of the entire project emphasizing in particular detail the first olefin unit and complementary derivatives units, pipeline transportation and liquids extraction facilities, off-site facilities such as power generation storage, docks, and warehouses.

(b) Selection of sites for all portions of the project and description of required infrastructure details.

(c) Environmental and social impact analysis in sufficient detail to allow the State to determine environmental and social costs and benefits.

(d) A complete financing plan.

(e) A construction time line.

(f) A manpower plan, including hiring schedules, necessary training requirements and proposed training programs.

(g) A proposed future development plan covering the options of existing site expansions and potential new sites.

In the event the project is terminated for lack of feasibility, the State shall retain the right to use the feasibility study as it sees fit. The Sponsors, however, will not include proprietary or confidential information on any process technology or marketing in the study, and will not make such proprietary or confidential information available for State use.

6. **Progress Reports to the State.**

Sponsors agree to provide oral progress reports on the Feasibility Study to the State upon request and Sponsors shall submit monthly progress reports to the State beginning with the end of the third month following the execution of this memorandum.

7. **Negotiations of Producers NGL Sales Agreements.**

Sponsors agree to immediately negotiate contracts with North Slope Producers for the purchase of natural gas liquids to supplement liquids to be purchased from the State of Alaska.

8. **In-State Requirements.**

Sponsors recognize that the first priority of Alaskan royalty hydrocarbons is for in-state use. If Sponsors enter into an agreement to purchase royalty natural gas liquids (NGLs), Sponsors will include in such agreements provisions which:

(a) Recognize the priority of providing propane and butane for use throughout Alaska.

(b) Make available, subject to reasonable notice from in-state users of their requirements, on a priority basis for in-state consumption all products derived from such NGLs.

9. Purchase of Producer Natural Gas Liquids.

Sponsors desire to enter into long-term contracts with Producers to purchase available NGLs. Sponsors will offer to pay fair market value based on delivery to dominant U.S. markets such as the West Coast and Gulf Coast for such hydrocarbon products.

10. Technical Assistance.

Sponsors agree to provide appropriate engineering expertise to the State during the design of the conditioning plant/gas pipeline and to the State's contractor for the NGL pipeline design/cost study. Sponsors specifically commit to providing analysis of the Selexol process (chosen by Parsons for the gas conditioning plant) which will optimize NGL recovery. These studies will include a comparison of the Selexol and Sulfinol processes and will review alternative North Slope values for NGLs. Shell will provide Sulfinol process expertise and will provide a Sulfinol process expert to work with the State during design of the conditioning plant. This assistance will be made available immediately upon the Task Force's choice of Sponsors as the single group to proceed with the project.

11. **State and Community Participation in Feasibility Study and Project Development.**

(a) State participation on the Dow-Shell Group Executive Committee. The Group requests that the Governor appoint one Task Force Committee member (and one alternate, who is also a Task Force member) to serve on such Executive Committee. The Executive Committee will be comprised of representatives from each company in the Dow-Shell Group and will meet regularly to direct and review progress of the study.

(b) State participation on the Dow-Shell Group Environmental Sub-Committee. The Group requests that the Commissioner of Environmental Conservation be appointed by the Governor to serve as a member of such Environmental Sub-Committee which shall be comprised of representatives from each company in the Group. The Environmental Sub-Committee will review activities relating to permitting and compliance with State and Federal environmental protection requirements and will recommend actions to be taken by the Group.

(c) Alaska Citizens Advisory Council. The Group requests that the Lieutenant Governor name a five person Alaska Citizens Advisory Council to monitor the development of the project from the standpoint of environmental and social impact. The council, which should be comprised of interested and informed citizens, shall make periodic reports to the State which shall also be made available to the public.

(d) **Community Advisory Board.** Upon selection of facility sites and related transportation routes, the Executive Committee will establish a Community Advisory Board which shall include representatives of communities which will be directly affected by development of the project. The purpose of this Board is to ensure that the Group is made aware of local community problems and issues so that mutually satisfactory solutions may be achieved.

12. Comprehensive Energy Study.

The Group agrees to complete and submit to the State a study detailing the project's electrical power requirements and alternative means of meeting those requirements. In addition to plant and transportation requirements, the study will also include the projected energy requirements of communities directly affected by the project.

The power supply systems to be evaluated include on-site generation, cogeneration, mine-mouth wheeled power, expansion of existing utility systems, and hydroelectric power. The study will address the merits of interconnecting with local public utilities and power grids for the purpose of facilitating more economical power for Interior and Southcentral Alaskan consumers.

13. Training of Alaska Residents.

Sponsors, in order to provide for maximum practical job opportunities for Alaska residents in the construction, operation, and maintenance of the project, shall include as a part of its Feasibility Study a specific job training program to be followed by Sponsors to acquire needed skills in Alaska. Such a plan shall consider existing and planned Alaskan educational agencies and facilities, as well as the resources of Sponsors.

14. Negotiation of Royalty NGL Sales Agreement.

In order to insure timely approvals and ratification of a long-term agreement for the purchase of royalty natural gas liquids by Sponsors, assuming State and Sponsors mutually agree to proceed with the project, State and Sponsors agree to use their best efforts to negotiate and complete, insofar as possible, a form of long-term natural gas liquids sales agreement. The goal of these negotiations shall be to submit any such contract to the Alaska State Legislature in the 1981 session, should the parties to this memorandum mutually so desire.

RESPONSIBILITIES OF THE STATE

15. Design of Gas Pipeline.

With recognition that some regulatory matters have already been decided, the State shall use its best efforts to maximize the availability for off-take in Alaska of natural gas liquids, including ethane, in the design of the Alaska Natural Gas Transportation System and associated conditioning plant through the state's seat on the management/design boards formed for the purpose of designing the gas pipeline and conditioning plant, except that the state shall not be required to advocate any positions to that board which are inconsistent with the state's best interests.

16. Non-Royalty Liquids.

The State shall use its best efforts to assist Sponsors in securing non-royalty natural gas liquids, including ethane, produced from the Prudhoe Bay Unit, except that the State shall not be required to take any action inconsistent with its best interests.

17. Project Site Infrastructure.

After notification by Sponsors of potential sites for its project, the State shall examine the infrastructure, such as roads, docks, and other facilities which may be needed for the project and consider provision of these facilities if consistent with the State's interests.

18. Incentives to Project.

The State shall examine what incentives (e.g., tax exempt financing) to the building of a project by the Dow-Shell Group can appropriately be granted by the State under state law.

19. State Study of Liquids Line.

The State shall provide Sponsors with the results of a study on a natural gas liquids pipeline to be performed by the Alaska State Legislature as presently authorized.

20. Decision to Participate in Project.

If the Feasibility Study submitted to the State concludes that the Dow-Shell Group's project as described in the study is feasible, and the Sponsors notify the State that they wish to proceed with the project, the State shall review the proposal and determine in writing whether it is in the State's best interest to participate in the project by sale of its royalty natural gas liquids, including ethane, to Sponsors.

21. Negotiation of Sales Contract for Liquids.

If the State determines in writing that it is in its best interests to participate in the project, the State will negotiate in good faith with Sponsors to sell the State's natural gas liquids, including ethane, available to be sold from the State's royalty share from the Prudhoe Bay Unit to

Sponsors. Any contract for sale of liquids resulting from these negotiations shall contain terms substantially similar to the following terms:

(a) A provision requiring that the price paid to the State be equal to the prevailing value paid by Sponsors for non-royalty natural gas liquids, including ethane, from the Prudhoe Bay Unit, but in no event less than the State would have received if the State had taken its royalty gas and gas liquids in value rather than in kind.

(b) A provision requiring the State to use its best efforts to assist the Dow-Shell Group in securing any necessary federal right-of-way leases or federal permits, except that the provision will not require the state to take any action inconsistent with its best interests.

(c) A provision requiring the State to expedite issuance of any necessary State right-of-way leases or State permits if the Dow-Shell Group satisfies the requirements of State law and regulation.

(d) A provision for instate use substantially similar to the terms contained in paragraph 8.

GENERAL PROVISIONS

22. Best Interests of the State.

Notwithstanding any provision of this memorandum requiring the State to take specific actions, the State shall not be required to take any action which the State determines is not in its best interests. The State, acting through its Commissioner of Natural Resources, shall in its sole discretion, determine what actions are or are not in its best interests. It is the intention of the parties that the State's discretionary determination of its own best interests not be subject to judicial review in any court. This memorandum is not meant to commit the State to the expenditure of funds to pursue its responsibilities except as expressly stated in this memorandum.

23. Due Diligence.

Each party shall proceed to perform the acts described in this agreement with due diligence.

24. Assignment.

Sponsors shall not assign this memorandum without first obtaining the written consent of the State.

25. Non-Warranty.

The State does not warrant or agree to any matter not specifically set forth in this memorandum, including but not limited to natural gas liquid feedstock availability.

26. Term.

This memorandum is effective on the date it has been executed by the State and both Sponsors and shall continue in full force and effect until the first of the following occurrences.

(a) This memorandum terminates if either party reasonably decides that the purposes or items listed in this memorandum have not been or will not be accomplished. The party wishing to terminate this memorandum will notify the other party in writing of its wish to terminate and will set forth the reasons and basis for the party's reasonable belief that the purposes or items listed in this memorandum have not or will not be accomplished. Those reasons may include, but are not limited to, lack of due diligence by the other party in performance of any of the acts required of that party by this memorandum. The parties shall discuss whether or not the alleged situation exists. This memorandum will terminate thirty days after receipt of the notice unless the party wishing to terminate cancels the notice of termination. In any event, the termination of this memorandum shall be the sole liability or penalty to which either party shall be subject for any failure by a party to accomplish the purposes or items listed in this memorandum.

(b) This memorandum terminates if the Feasibility Study described in this memorandum is not submitted by twelve months after the Governor's selection or if, pursuant to this memorandum, the State determines that its participation in the project is not in the State's best interest.

(c) This memorandum terminates if Sponsors and the Commissioner of Natural Resources of the State of Alaska have not executed an agreement for sale and purchase of the State's royalty natural gas liquids from the Prudhoe Bay Unit within 75 days after submission of the Feasibility Study described in this memorandum.

(d) This memorandum terminates on the date of legislative approval of an agreement for sale and purchase of the State's royalty natural gas liquids from the Prudhoe Bay Unit between Sponsors and the State, or, on the date of execution of such an agreement by the Commissioner of Natural Resources, if legislative approval of that agreement is not required by valid state law or the agreement itself.

(e) This memorandum terminates if an agreement for sale and purchase of the State's royalty natural gas liquids from the Prudhoe Bay Unit between Sponsors and the State is submitted to the Alaska State Legislature and is not approved or is disapproved by the Legislature during the session at which it is submitted.

Each party has agreed to the terms of this memorandum on the date opposite its signature. Sponsors, Participants and Affiliate represent that each has obtained all approvals necessary to execute this memorandum.

This memorandum may be signed in multiple counterparts which shall be considered together as a single instrument.

STATE OF ALASKA

Date: 8 September 1980 By: Robert E. LeResche
Commissioner, Department of Natural Resources
STATE

DOW CHEMICAL USA

Date: 9-8-80 By: J. D. Hembree
Title: Group V.P.

SPONSOR

SHELL CHEMICAL COMPANY

Date:______________ By:______________
Title:

SPONSOR

CONCURRENCE OF PARTICIPANTS AND AFFILIATE:

ALASKA INTERSTATE COMPANY

Date: August 28, 1980

By: Willard M. [illegible]
Title: Vice President

PARTICIPANT

ASAHI-DOW, LTD.

Date: Aug 28, 1980

By: [illegible]
Title: Managing Director

PARTICIPANT

DOYON, LTD.

Date: ____________________

By: ____________________
Title:

PARTICIPANT

E. I. duPONT de NEMOURS

Date: ____________________

By: ____________________
Title:

PARTICIPANT

EARTH RESOURCES COMPANY OF ALASKA

Date: August 28, 1980

By: [illegible]
Title:

PARTICIPANT

MITSUBISHI CHEMICAL INDUSTRIES, LTD.

Date: 8. 28. 1980

By: [signature]
Title:

PARTICIPANT

MITSUBISHI CORPORATION

Date: August 28, 1980

By: [signature]
Title:

PARTICIPANT

ALASKA INTERIOR RESOURCES
COMPANY, INC.

Date: ______________

By: [signature]
Title: of Vice Pres.

AFFILIATE

CONCURRENCE OF PARTICIPANTS AND AFFILIATE:

ALASKA INTERSTATE COMPANY

Date: August 28 1980

By: Willard M. [illegible]
Title: Vice President

PARTICIPANT

ASAHI-DOW, LTD.

Date: Aug 28. 1980

By: [illegible]
Title: Managing Director

PARTICIPANT

DOYON, LTD.

Date: ______

By: ______
Title:

PARTICIPANT

E. I. duPONT de NEMOURS

Date: Sept. 10, 1980

By: R. C. Forney
Title: Sr. Vice-Pres.

PARTICIPANT

EARTH RESOURCES COMPANY
OF ALASKA

Date: August 28, 1980

By: [illegible]
Title:

PARTICIPANT

Each party has agreed to the terms of this memorandum on the date opposite its signature. Sponsors, Participants and Affiliate represent that each has obtained all approvals necessary to execute this memorandum.

This memorandum may be signed in multiple counterparts which shall be considered together as a single instrument.

STATE OF ALASKA

Date:______________________ By: ______________________
Commissioner, Department of Natural Resources

STATE

DOW CHEMICAL USA

Date:______________________ By: ______________________

Title:______________________
SPONSOR

SHELL CHEMICAL COMPANY

Date: 8-27-80 By: ______________________

Title: Vice President
SPONSOR

CONCURRENCE OF PARTICIPANTS AND AFFILIATE:

ALASKA INTERSTATE COMPANY

Date:______________________ By: ______________________

Title______________________
PARTICIPANT

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

POUCH M – JUNEAU 99811
(907)465-2400

November 4, 1980

Mr. Jim Hembree
Dow Chemical Company
2040 Dow Center
Midland, Michigan 48640

Mr. Brian Turner
Shell Chemical Company
One Shell Plaza
Houston, Texas 77001

Gentlemen:

Pursuant to our recent conversations, the State of Alaska hereby amends Article 11 (c) of the Memorandum of Understanding between the State and the Dow/Shell Group, so that the membership of the Alaska Citizens Advisory Council is expanded from five persons to seven persons, subject to your concurrence.

Sincerely,

R LeResche

Robert E. LeResche
Commissioner

CONCUR:

DOW CHEMICAL USA	SHELL CHEMICAL COMPANY
By: [illegible]	By: Brian A. Turner
Title: [illegible] V.P.	Title: PROJECT Mgr
Date: 11/12/80	Date: 11/12/80

10-J9LH

QUESTIONS FOR MILTON LIPTON PRESENTATION

1a. WHAT EFFECT DO STATE OF ALASKA TAXES ON THE OIL INDUSTRY (i.e. SEVERANCE TAX, CORPORATE INCOME TAX) HAVE ON THE RETAIL PRICE OF HOME HEATING FUEL AND GASOLINE, HERE IN ALASKA AND ELSEWHERE?

1b WHY?

2. DO YOU BELIEVE THAT ALASKA PRESENTLY ENJOYS A REALISTIC PRICING POLICY OF PETROLEUM PRODUCTS IN TERMS OF THE COST OF ENERGY AND FUEL TO THE ALASKAN CONSUMER?

3. WHAT IS YOUR OPINION OF THE STATE ROYALTY OIL PRICING AND SUPPLY POLICY VIS-A-VIS INCREASED IN-STATE REFINING CAPACITY?

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

5

NET ECONOMIC BENEFIT

TO ALASKA

OF ALASKA NATURAL GAS TRANSPORTATION SYSTEM

MARCH, 1982

Prepared by
Milt Barker
Legislative Finance Division

With Review by
Department of Revenue
Department of Natural Resources
and
Budget and Management, Office of the Governor

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(continued)

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Net Economic Benefit to Alaska
of the Alaska Natural Gas Transportation System

SUMMARY

Construction and operation of the Alaska Natural Gas Transportation System (ANGTS) could easily provide in excess of $5 billion in present value of economic benefits to Alaska in 1982 dollars if the effects of construction on price levels in Alaska can be held to a minimum. If the inflationary impact of construction is not held in check, its adverse consequences could result in a real net cost to the state from ANGTS.

The assumptions behind these conclusions are very conservative. Limited time and resources were available for testing alternate assumptions. Since the most important question to be answered by this sort of analysis is whether on the whole economic benefits are positive or negative, conservatism supplies a "failsafe" test. If benefits are positive, or nearly so, in the worst imaginable case, the project can be endorsed with confidence.

Arguably this is so for ANGTS. The high inflationary impact case assumed price level escalation slightly in excess of the Trans-Alaska Pipeline System (TAPS) experience and persistence of these elevated price levels for eleven years. Such an impact would result in a net cost to the state of almost $1 billion.

The extraordinary inflation associated with ANGTS is assumed to occur during and immediately following the construction period. The persistence of elevated price levels, resulting from inflation during that period, is assumed in order to provide a worst case test. A large backlog of state capital projects and continued high levels of state spending of petroleum revenues might result in such persistence.

Since one can never know what the future will hold, some find it helpful to think in terms of probabilities. If one feels that there is no more than an 80% chance of the high inflationary impact, as specified here, occurring, then one can expect the project to result in positive benefits.

In light of the possibility of negative benefits to Alaska from ANGTS, it may be felt that prudence requires a much more extensive testing, and judgment as to likelihood, of alternate assumptions before the state endorses the project or makes any commitments for financial support.

Specific findings or propositions from the economic benefit analysis are:

1) benefits of ANGTS are:

   a) an increase in the present value of Sadlerochit oil production if gas is also produced;

   b) higher bonus, royalty, or net profit share bids on lease sales;

c) availability of property and sales taxes in excess of local government expenditures for ANGTS impact;

d) an increase in income and wealth of Alaska residents resulting from wage gains and increased corporate profits;

e) availability of gas revenues in excess of state expenditures for gasline impact if there is a minimal ANGTS inflationary impact;

f) high inflation can create significant windfalls to property owners who are leveraged;

2) costs of ANGTS are:

a) the increase in state expenditures required to maintain existing levels of service can exceed gas revenues, with a high inflation impact from ANGTS;

b) the greatest cost of a high inflation impact can be the reduction in value received for the expenditure of state revenue in excess of the amounts required for existing levels of service;

c) even low inflation will reduce the real value of permanent fund dividends more than gas royalties increase them for as long as the elevated price levels persist; population increases will further dilute their value to individuals;

d) high inflation can significantly erode the value of government assets and personal savings;

e) the inflationary impact of the gasline could be compounded by high levels of state spending at the same time;

3) the state may have some capability to assist in ANGTS financing:

a) there might be general funds available for investment between FY 84 and FY 88; however, this possibility is becoming increasingly clouded by current oil market developments;

b) the state's gas royalties from Sadlerochit would have a present value of roughly $1.5 billion in 1982 dollars at a minimum;

4) the amounts of gas revenues estimated in the analysis are conservative in that:

a) gas liquids may provide additional revenues;

b) gas marketability may not require reduced wellheads at the outset, as projected, if tariffs are levelized and/or rolled-in pricing is possible;

c) oil prices and the controlled gas price of the Prudhoe Bay Unit may increase faster than projected;

d) decontrol of Prudhoe Bay Unit gas might mean greater revenues in the long run;

5) the amounts of gas revenues are optimistic in that delivered gas prices are assumed to have parity with oil prices in Btu terms;

6) levelization of ANGTS tariffs probably would increase state benefits if Prudhoe Bay prices remain controlled; however, levelization might decrease state benefits if Prudhoe Bay prices are decontrolled;

7) the state may have an interest in further analyzing marketability measures that may be undertaken by FERC to determine their effect on state revenues and possibly to try to influence such decisions.

NET ECONOMIC BENEFIT TO ALASKA OF THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

I. CONCEPT AND METHODOLOGY

Definitions

The net economic benefit to Alaska of the Alaska Natural Gas Transportation System (ANGTS) is composed of the change in revenues and expenditures of state and local governments, the change in personal income of Alaskan residents, and the effects of inflation in Alaska in excess of national rates of inflation which are attributable to construction and operation of the gasline. The revenue, expenditure, and personal income items include the multiplier effects of ANGTS construction.

The present value of the net economic benefits is the value today of the benefits and costs to be received or incurred in future years. The present value is less than the actual benefits when they occur because the present value, invested at some positive rate of return, would compound to the amount of the future benefit. Thus, one would be indifferent between the present value received today and the actual value received in the future.

Purpose

This economic benefit study seeks to provide guidance to the state in answering the question "to what extent should the state support the ANGTS project, if at all?". State support could be either in the form of subsidies, investment, or non-financial support such as permitting and regulatory measures.

To answer this question, the benefits from state support of ANGTS should be compared to the benefits of all other uses of state funds. This is not practical. As a surrogate, the next best use of state funds is assumed to provide a real rate of return of 3% per annum. If the present value of ANGTS benefits -- calculated by using 3% as the state's opportunity cost -- is positive, then support of ANGTS, if necessary, would be a better use of state funds than other alternatives. If the present value is negative, the state should not support ANGTS.

More specifically, consider the following possible outcomes:

a) if state support is critical to the project's completion, the state in theory should be willing to subsidize ANGTS up to the amount of positive benefits in present value terms that the state would receive. Subsidy means both direct payments or grants or tax relief as well as acceptance of a return on investment less than 3% per annum.

b) if state support is not crucial and the present value of benefits is positive, there should obviously be no subsidies and any investment by the state would have to earn at least 3% in real terms. In this situation, an investment by the state in the ANGTS can be evaluated on its own terms, with due consideration for alternative investment opportunities, alternative expenditure priorities, diversification, risk and regulatory conflicts.

c) if the present value of benefits is negative, there should obviously be no subsidies and the earnings on any investment by the state would have to exceed the normal earnings or opportunity cost of 3% on state investments by the amount of the present value.

It should be noted that there are at least two ways in which use of this economic benefit analysis may be a defective guide to decision-making:

a) there is no consideration of environmental or socioeconomic effects such as congestion, crime, etc.

b) the benefits are calculated by comparing the ANGTS project to not producing Prudhoe gas at all; the correct approach would be to compare it to the next best alternative, be it methanol, use as in-state boiler fuel or whatever; in other words, the gas is assigned a zero opportunity cost when it may really have some value even if ANGTS is not built.

Method of Analysis

The benefits of ANGTS are estimated for four different gasline construction cases representing combinations of low and high inflation scenarios and weak and strong state expenditures. Comparison of these cases reveals how sensitive the estimated benefits are to assumptions about inflation and spending. The benefits for the four cases are calculated as the difference from base cases of weak and strong state expenditures in which there is no gasline.

The low inflation scenario assumes gasline construction results in cumulative inflation totaling 5.55% in excess of the base case (no gasline). See Table IX. This level of inflationary impact is assumed to be consistent with construction of ANGTS at the IROR (incentive rate of return) centerpoint cost. This cost is the estimated cost of construction as filed with the Federal Energy Regulatory Commission (FERC) by Northwest Alaskan Pipeline Company plus 30% as an allowance for anticipated but unidentified cost overruns. These overruns are assumed to result generally from unforeseen technological and managerial problems.

The <u>high inflation scenario</u> assumes gasline construction results in 18.06% inflation in excess of the base case. This high estimate of inflation is assumed to be consistent with a construction cost 10% in excess of the centerpoint cost (or roughly 40% over filed costs). The annual rates of excess inflation for this scenario are shown in Table X.

The <u>weak state expenditure scenario</u> is modeled on the assumption that per capita expenditures remain at FY 82 levels of service in real dollars.

In the case of capital expenditures, this means the capital budget shrinks to an amount equal to one-twentieth of the value of capital stock (cumulative, depreciated capital expenditures as shown in Table XVIII) escalated by changes in population. This is all that is required to maintain the existing level of capital stock if one assumes it depreciates to zero over a twenty year period. 1/

Highway repair costs resulting from gasline construction have been estimated separately in Table XV and are added to the capital budget amount required for non-highway capital stock during the years of construction. 2/

1/ As a practical matter, because capital facilities often come in large chunks, expenditures may be more than they would be if they could be provided in truly per capita increments. However, governments could also choose to tolerate congestion in use of existing facilities rather than create excess capacity.

2/ In 1978 Northwest agreed in principle to reimburse the state for highway repair costs and socioeconomic impact costs. However, they are indicating that they will make reimbursement only for those costs that are allowed in the rate base by FERC. The state pipeline coordinator's office has estimated $19.7 million (in FY 80 $) in state costs during FY 81-88 for migrants and their families directly employed on the gasline and $96.6 million additional costs for migrants and families induced to come to Alaska by ANGTS construction but not directly employed on the line. These costs are based on FY 80 levels of service. See the attached letter of July 21, 1980 from Commissioner Ward of the Alaska Department of Transportation and Public Facilities to Northwest regarding highways costs. The socioeconomic cost estimates are based on "The Relationship Between the Alaska Natural Gas Pipeline and State and Local Government Expenditures", Goldsmith and Mogford, Institute of Social and Economic Research, December 1980 and state agency estimates. Northwest is (continued-next page)

The FY 82 level of service budgets take into account the facts that not all state operating and capital expenditures are related to population changes and that the composition of migrant families is different from the average Alaskan family, thus not requiring the same pattern of state expenditures.

The strong state expenditure scenario projects state expenditures at the level that would be permitted if the proposed constitutional spending limit, Legislative Resolve 1, SLA 1981, is ratified by the voters.

In this scenario, the impact of the gasline on expenditures is greater first of all because the base for capital budgets under the spending limit is not one-twentieth of the value of the state's capital stock, but a much larger amount based on FY 82 capital expenditures. Secondly, spending limits will go up in full proportion to population increases, not just by the fraction of the budget that is population sensitive or responsive to migrant demographics. Compare Tables XIII and XIV.

The FY 82 level of service budgets are a fairer measure of what costs can be assigned to gasline impact in that costs rise only to the extent required to maintain the given level of service. However, the spending limit budgets are a more realistic estimate of what the actual level of services will be.

Components of Economic Benefit

The specific elements of economic benefits for which quantitative estimates are shown in Tables I and II need some explanation.

For state government, net economic benefit is composed of:

1.) the change in the FY 98 general fund balance
    a.) this figure measures the effect of both the increased state expenditures resulting from gasline impact and the increased state revenues from the gasline for the entire period FY 83 through FY 98;

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2 continued/ reimbursing the state for pipeline surveillance and monitoring which is budgeted at $51.3 million for FY 81-88. Any of these costs allowed in the rate base could result in an adverse though miniscule effect on wellhead values and a definite though miniscule increase in pipeline income taxes.

b.) it also measures the erosion of the real dollar value of the general fund balance due to gasline caused inflation; the FY 98 figure is in 1982 $ which in the gasline scenarios means it was reduced by an additional 5.55% or 18.06% compared to the no gasline base case; these percentages are the additional inflation generated by gasline construction;

2.) the <u>change in the FY 98 permanent fund balance</u>

a.) this figure accounts for the increase in the balance as a result of 25% of Prudhoe Bay unit gas royalties being deposited in the fund between FY 83 and FY 98;

b.) the figure also measures the erosion of fund value caused by additional gasline-related inflation as described above;

c.) the extent to which this figure is positive or negative would indicate whether the total value of permanent fund dividends in real dollars increased or decreased without considering the dilution that would come from population growth caused by the pipeline; if 50% of earnings at 12% interest are paid as dividends, the effect on annual dividends would be 6% of the effect on the fund balance;

3.) <u>FY 99-2016 gas revenues</u>

a.) beyond FY 98, additional state expenditures and inflation resulting from the gasline are ignored;

4.) <u>FY 86-2016 reduced oil recovery</u>

a.) counted as an economic cost in this analysis is a total reduction in Sadlerochit oil recovery of 140 million barrels as a result of gas production. This is based on van Poollen's March 1980 reservoir simulation of oil production with waterflooding, with and without gas production;

5.) <u>gas revenues from other fields</u>

a.) ANGTS would make possible gas revenue from reservoirs other than Sadlerochit depending on the economics of production; a September 25, 1980 Department of Natural Resources study, "Proven and Probable Oil and Gas Reserves, North Slope, Alaska" estimated 6.4 trillion cubic feet (TCF) in gas reserves on North Slope acreage leased at that time in addition to Sadlerochit; 3/

3/ Point Thomson and Flaxman Island areas - 4.5 TCF; Lisburne reservoir, Sag Delta and Duck Island areas - 1.9 TCF.

b.) ANGTS would also increase gas revenues by increasing bonus, royalty, or net profit share bids on acreage yet to be leased;

6.) erosion of other state assets

a.) other state assets such as the retirement funds and the rainy day fund will be worth less as a result of gasline-caused inflation;

b.) asset values are based on 1980 fund levels; roughly speaking, changes from this level would have to come from the general fund; thus, the analysis of gasline impact on the general fund avoids the necessity of considering future balances of these other assets.

Local government benefits are the excess of revenues over expenditure based on 1979 levels of service per capita. Additional revenues are from property taxes and sales taxes.

The figures for local government include only the gasline construction years. This is the period of major impact. 4/ It is assumed that both revenues and expenditures of local governments keep pace with inflation. Thus, the lingering effects of gasline inflation after the construction period make no difference in economic benefits in real dollars.

Private sector benefits include increases in corporate profits of Alaska-owned businesses and increases in wages of existing Alaska residents. For estimating the wage gains, it is assumed that only gasline jobs result in wage gains in real dollars and that existing residents receive 60% of the gasline jobs.

4/ Fairbanks will continue to receive some significant additional property taxes on the gasline after construction. The North Slope Borough will receive additional property taxes only during construction when construction workers are present. This is because the borough is already at its per capita property tax limits.

II. RESULTS AND SENSITIVITY

Results

For the state as a whole, and for all three sectors -- state government, local government, and the private sector -- the gasline provides significant benefits if it does not cause much additional inflation in the state.

If there is significant inflation, then state government potentially is a loser even though local government and the private sector remain immune from any adverse effects. The effect on the state as a whole could be negative.

The negative effects of gasline inflation on state government come about because 95% of the state's general fund revenues, namely petroleum revenues and interest income, would not increase with inflation that occurs only in Alaska. These revenues are determined by world and national markets and price levels. Thus, gasline inflation eats away at the real value of the state's revenues as state expenditures rise with inflation while petroleum revenues and interest remain unaffected. The other way of looking at this is that each dollar of state revenue purchases less real goods and services.

Interpretation of Effects on State Government

A. GENERAL FUND

In the low inflation scenarios, it is clear that the main result of ANGTS would be to increase state revenues well in excess of any need for increased state expenditures or ill effects of inflation.

In the high inflation scenarios, clearly the effects of inflation predominate and require some further interpretation.

In comparing FY 98 fund balances, the gasline scenarios' fund balances in real dollars are reduced by the additional inflation caused by the gasline. This implies that the effects of gasline-caused inflation on price levels persists indefinitely or that the fund balances are spent before the effects of gasline-caused inflation have receded. The first implication is very unlikely -- the second, rather likely.

The general fund balances shown in Tables I and II combine two adverse effects of inflation which can be segregated.

The first effect of inflation would be to increase the state expenditures required to maintain a given level of service.

This effect can be most clearly discerned by examining the FY 82 level of service budgets. 5/ If one compares FY 98 general fund balances without adjusting the gasline scenario balances for any additional inflation caused by the gasline, one can determine that in the high inflation case the general fund balance is $628.5 million (1982 dollars) less than in the base case. This is the extent to which the increase in state expenditures required to provide the existing level of services would exceed gasline revenues. The culprit is sure to be inflation rather than population impact from ANGTS, since the change in the general fund balance is positive in the low inflation case.

The second effect of inflation, the reduction in real goods and services that would be received from expenditure of state revenues in excess of those required to maintain the FY 82 level of service, would amount to $4,635.8 million. 6/ The expenditure of these funds is not caused by gasline impact but gasline impact would reduce the value received for them. 7/

B. PERMANENT FUND

Assuming the excessively high price levels resulting from gasline inflation eventually return to normal, the effects of inflation on the permanent fund balance could be ignored. Arguably this is so, since the permanent fund balance is never supposed to be spent. In that case, the FY 98 permanent fund balances would be $290.6 million and $260.1 million higher in 1982 dollars in the low and high inflation scenarios than in the base case.

5/ As previously discussed, the spending limit budgets provide increasing levels of service, especially through capital expenditures in excess of those required to maintain existing stock.

6/ The difference between the $628.5 million decrease in the general fund in the preceding paragraph and the total decrease of $5264.3 million shown in Table II is $4,635.8 million.

7/ It should be noted that in the high inflation scenario, reliance upon the spending limit budget for evaluation of gasline benefits would be misleading. The spending limit case shows the cost (negative benefit) of ANGTS to be smaller than the FY 82 level of service case. The reason is that the most significant effect, the erosion of general fund assets by inflation, is diminished because the high rate of spending has already diminished general fund balances. The problem is that the reduction in value received for these greater expenditures is not measured.

However, as discussed previously, this item serves to indicate the change in the value of permanent fund dividends. The longer the effects of gasline inflation persist, the closer the effect on permanent fund dividends comes to the effect shown for the permanent fund balance.

C. REDUCED OIL RECOVERY

When the difference in oil recovery between the gasline cases and the base cases is present valued, the economic cost of reduced oil recovery becomes a positive benefit. This requires some explanation.

The effect occurs because there can be greater oil production until FY 98 if gas is also produced. There will be less oil produced thereafter and total recovery is less for the entire period 1986-2015. But the possibility of earning interest on revenues from greater production during the early years can offset the net loss in recovery under certain assumptions about oil prices, and does in this case.

Expected Value 8/

If one were to use FY 82 level of service budgets as the best measure of economic benefits, assign equal probabilities to high and low inflation and a 20% chance to the line never being completed once it's begun, the expected present value of the benefits of ANGTS to Alaska would be $1,455.1 million in 1982 dollars.

Taking a less rosy view and assigning a 75% chance to high inflation and a 25% chance to low inflation and a 50% chance to the line not being completed, the expected present value would be $212.6 million.

Arguably, factoring in non-completion is relevant only for investment purposes and not for calculating economic benefits which would be received if the line is completed. In that case, the two previous expected values would be $1,818.8 million and $425.3 million.

However, factoring in a zero benefit for non-completion could be conservative. Non-completion could have most of the negative effects of gasline impact expenditures and gasline inflation with none of the positive effects of gasline revenues.

8/ Expected value is the average of several values weighted according to their probability of occurence.

Sensitivity to Inflation

The net economic benefits of ANGTS and their present value can be judged by Tables I and II to be highly sensitive to inflation. The swing in economic benefits approaches $9 billion between the high and low inflation scenarios in the case of a weak state spending response. The swing occurs entirely in state government benefits. Local government and the private sector are unaffected by inflation.

The results are partly a reflection of the assumption that the relatively higher price levels induced by the gasline persist through FY 98. One might ordinarily expect the rate of inflation to subside to less than normal rates in the aftermath of construction.

The experience with construction of the Trans-Alaska Pipeline System (TAPS) is an interesting comparison in this regard. Table XI shows that indeed sub-normal inflation rates finally did begin to occur two years after TAPS became operational. Four years after completion about one-sixth of the effect of TAPS inflation on price levels had been erased.

The assumed persistence of gasline-caused relative price levels through FY 98 could occur as a result of record levels of state spending of oil revenues throughout the period. Going into FY 82, the state had a backlog of $2,541.6 million in capital projects. 9/

The change in benefits as a result of inflation also clearly depends on the level of gasline inflation.

Again, the level generated by TAPS, 15.83%, is interesting by comparison. Arguably, the fact that Alaska's economy will be significantly larger when ANGTS is constructed, and the fact that ANGTS is presumably being more carefluly planned and managed for cost control and may have a lesser percentage of its expenditures in Alaska, means that it will generate less inflation than TAPS did.

9/ $769.9 million in general fund projects and $391.7 million in bond fund projects as of June 30, 1981 according to the "Annual Financial Report" of the state for FY 81 plus FY 82 capital appropriations of $1380.0 million.

On the other hand, the 18.06% high inflation figure for ANGTS could conceivably be low if construction occurs against a backdrop of an already overheated Alaskan economy resulting from expenditure of state petroleum revenues. The attached letter of January 29, 1982 from John Bates, Deputy Commissioner, Alaska Department of Transportation and Public Facilities, re: "construction costs escalation" is of interest in this regard. His letter states that material cost and "wage increases could easily result in a construction escalation rate of 2% per month (24% per year) in 1982".

Although there is the question of how much of the construction cost inflation gets translated into consumer price inflation, for much of the state budget, namely the capital budget, construction costs are very relevant.

In any event, the high inflation assumptions serve as a pessimistic case to test the sensitivity of project benefits to unanticipated levels of inflation.

The sensitivity of economic benefits from ANGTS to inflation is very suggestive as regards state expenditures and should give decision makers pause. At current levels of state expenditures, the state can be characterized as burning the candle at both ends. A substantial portion of the "principal" of the state's petroleum wealth, rather than only the interest thereof, is being spent, while the value of the remaining principal, whether in the ground or the permanent fund, is being eroded by inflation caused by the spending.

What should give one pause is the scale of the effect suggested by the gasline analysis with inflation rates paramount to what may now be occuring, as suggested by the aforementioned letter from John Bates. For state expenditures one can expect inflation's effect to be even greater than that suggested by the gasline analysis as there are unlikely to be any offsetting revenues commensurate with those from ANGTS.

This analysis suggests two important matters for consideration by budgetary decision makers -- one, slowing state expenditures, and two, timing capital expenditures to avoid the simultaneous construction of major projects such as a new capital, Susitna and ANGTS. Simultaneous construction could magnify inflation synergistically. Any positive benefits from ANGTS could easily be negated in such circumstances.

Sensitivity to State Expenditures

The benefits from ANGTS are not nearly so sensitive to state expenditures -- as long as higher expenditures can be achieved without generating inflation.

In the low inflation scenarios the pattern of spending makes little difference. This would very likely be the case in the high inflation cases as well if one measured the reduction in value received for the higher expenditures when spending up to the limit.

Further Sensitivity Analysis

This limited analysis could be expanded to consider the effects on ANGTS benefits to Alaska of various other overruns or underruns of ANGTS construction costs, oil price levels, relative parity of gas prices with oil prices, ANGTS tariff structures, treatment of conditioning costs, other gas reserves, etc. From this, the expected value of ANGTS benefits might be more meaningfully calculated.

Conservatism of Assumptions

Absent further sensitivity analysis, several things can be said about the relative conservatism of certain assumptions and the general effect on economic benefits of changes in those assumptions:

1.) gas liquids
even ignoring the possibility of petrochemical development based on gas liquids, some additional revenue could be received for gas liquids that might be put in TAPS; the assumed MMBtu to MCF ratio of 1.055 assumes some gas liquids go into ANGTS; the state will receive no revenue from gas or gas liquids consumed in the conditioning plant or for field operations;

2.) oil parity
gas delivered by ANGTS is assumed to be marketed at a price equivalent to that of oil in terms of Btu's; this may be optimistic; more likely, gas will sell at some discount from oil in Btu terms;

3.) oil prices
the price assumed for oil works out to be around \$36 per barrel 10/ in 1982 which is clearly too high in light of today's oil markets; the assumed growth rate of 8% per annum for oil prices may or may not be too high in the long run; 8% is less than the assumed inflation rate for Alaska of 9% absent gasline impact; Alaskan inflation has historically been 1.5 percentage points below U. S. inflation in normal times; rates of growth in oil prices in excess of 8% could greatly increase ANGTS' benefits to Alaska;

10/ \$5.13 per MMBtu for oil from Table VI in 1980 x 8% inflation to 1982 x 6 MMBtu per barrel of oil.

4.) gas prices

a.) Natural Gas Policy Act (NGPA) ceiling vs. netback price

the wellhead prices in this analysis are calculated as the lesser of a netback from the delivered sales price or the NGPA controlled price; this results in zero wellhead values for the first three or four years of production increasing over a few additional years to the NGPA ceiling price; this could be conservative for several reasons:

i.) producers might not agree to resolving the marketability problem in the early years by reducing wellhead values; the problem might be entirely or partially overcome by rolled-in pricing or levelizing the ANGTS tariff; now-lapsed gas sales contracts contained language that would have permitted reduction of wellhead values below the NGPA ceiling prices only in case of economic hardship and subject to renegotiation by all parties involved in ANGTS; if Sadlerochit gas is sold at the NGPA price from the outset or if higher prices are allowed by FERC later to recoup these amounts, the economic benefits from ANGTS would be roughly $1.6 billion greater; the present value of the benefits would be $600 million greater; 11/

ii.) if gas prices are decontrolled, losses at the wellhead to provide marketability in the early years might be overshadowed by much higher netbacks in later years if oil prices grow at rates greater than 8%; in present value terms this increase would be somewhat muted;

iii.) prices of gas from reservoirs other than the Prodhoe Bay unit would not be controlled even under NGPA;

11/ The figures quoted can be determined from the attached computer runs prepared by Chuck Logsdon of the Department of Revenue. His discounted cash flow figures were discounted at 10% to 1980; the above figures are discounts of 9% for inflation and 3% real rate of return for the present value figure, to 1982.

b.) NGPA price escalator
the U. S. inflation rate implied by this analysis (see item 3 above and Table XI) is 10.5% as measured by the CPI; the ceiling price escalator under NGPA is the GNP implicit price deflator adjusted to approximate the CPI; thus, this analysis should have escalated the NGPA ceiling by 10.5% rather than 8%;

5.) ANGTS tariffs
the gas price netback calculations assumed that ANGTS tariffs were higher in the early years and declined as the rate base was depreciated; if tariffs are instead levalized, state benefits may be greater if Prudhoe Bay prices remain controlled but relatively less if decontrolled; since tariffs are lower in early years, more total dollars over the project life will have to be paid to equity owners to give them the same rate of return; since the rate of return to be allowed is expected to be higher than the 3% (in real dollars) used to value state benefits, income taxes on ANGTS equity returns will be greater even in present value terms; however, the present value of state gas revenues at the wellhead would arguably be less by similar reasoning, at least in a decontrolled, netback price situation; the net effect could be negative since the wellhead revenue generally outweighs the income tax revenue; the state might want to develop a detailed analysis to better determine the effects on state benefits of levelized tariffs and/or reduced wellheads and possibly take a position on what means should be used to overcome marketability problems;

6.) population
the effects of population on state expenditures are conservative in two respects:

i.) the population impact of gasline and conditioning plant operations was not considered;

ii.) the population increase resulting from ANGTS was projected by the Institute of Social and Economic Research MAP model based on government spending at a level required to maintain the FY 81 level of service per capita; this analysis calculated costs based on maintenance of FY 82 level of service or some higher level resulting from spending at the spending limit; in either case provision of the same services to pipeline employees as the rest of the populace receives would result in higher state employment and total population;

7.) <u>conditioning costs</u>
the gas revenue figures assume that conditioning costs are passed on to consumers as part of the ANGTS tariff; even though the ANGTS waivers would make the plant part or ANGTS, there may still be some chance part or all of the conditioning costs would be borne by the producers and state through a reduced ceiling price or the allocation of costs between gas and liquids;

8.) <u>severance taxes</u>
the gas revenue figures are too low in that consideration was not given to the fact that severance taxes can be added on to the NGPA ceiling price; accounting for this would increase income taxes from producers.

III. WEALTH

Increases in real or financial wealth of Alaskans is an economic benefit that has not been estimated in the preceding analysis.

Real Wealth

As a result of ANGTS, there will likely be increased investment in plant and equipment in Alaska. This constitutes an increase in real wealth. Some portion of this will be owned by Alaskans.

The extent of investment in Alaska as a result of ANGTS is rather uncertain however because of the boom-bust nature of the development. The possible specter of excess capacity after the construction period may temper investment plans. This of course does not apply to development-type investments such as gas liquids-based petrochemicals that might accompany ANGTS.

Financial Wealth

Financial wealth is an increase in savings of individuals. The higher personal incomes of Alaskans resulting from ANGTS will undoubtedly result in some increase in their savings, which means higher incomes in the future.

To the extent the investment response to the prospect of ANGTS is limited, higher than usual profits from construction activity would accrue to existing businesses. As a result the value of these businesses increase, if only temporarily as a result of the boom-bust nature of ANGTS.

This might be perceived as an additional economic benefit because those who sell out during the high tide of gasline construction can experience a gain in financial wealth. However, if markets and information were perfect, the gain would equal the present value of the additional profits. These have already been counted as a net economic benefit to the private sector.

IV. INFLATION AND THE DISTRIBUTION OF INCOME AND WEALTH

In the economic benefit analysis, inflation was assumed to have no effect on the private sector. While this may be true as a whole, inflation may have different impacts on various groups within the private sector. These differing effects can occur with respect to both income and wealth.

Income

Some idea of the effect of inflation caused by ANGTS can be gained by looking at the TAPS experience. The following table shows that practically all employment groups had increases in real wages during TAPS construction from 1973 to 1976:

Alaskan Wage Rate Growth in the 1970s

Industry	Average Monthly Wage 1973	1976	1979	Increase (percent) 1973-76	1973-79
All Nonagricultural Employment	$1,006	$1,928	$1,741	92	73
Mining	1,617	2,705	3,370	67	108
Construction	1,635	4,041	2,910	147	78
Manufacturing	961	1,409	1,745	47	82
Transport, Communications & Public Utilities	1,141	2,023	2,264	77	98
Trade	778	1,149	1,239	48	59
Finance, Insurance & Real Estate	897	1,197	1,572	33	75
Services	751	1,499	1,272	100	69
Government	1,024	1,418	1,749	42	71
	*	*	*		
U.S. per Capita Annual Income	$4,981	$6,401	$8,706	29	75
Anchorage Consumer Price Index (Oct.)	123.8	167.6	211.4	35	71

Reprinted from "Analyzing Economic Impact in Alaska", Scott Goldsmith, Institute of Social and Economic Research, 1981.

By 1979, in the wake of TAPS construction, the wages of trade and services employees had decreased in real terms compared to pre-pipeline days.

However, the effect on individuals in trade services may not have been negative. The decline in real wages may have resulted from changes in the kinds of jobs or skill levels of employees as younger or less experienced employees moved into these jobs. It may reflect a decline in the number of hours worked.

Wealth

Possibly the most significant effect of gasline inflation on the private sector is to transfer financial wealth from lenders to borrowers.

The total value of assets held by borrowers will increase with inflation. However, debt service costs, which are generally at fixed interest rates, will remain the same. Thus, the inflationary increase on the portion of assets financed by debt will accrue as additional financial wealth to the owner upon sale.

A rough estimate of this increase in borrower's financial wealth can be made. Total assessed property values in Alaska as of Janaury 1, 1981 were $16.6 billion excluding oil and gas property. If the high inflation estimate of 18.06% is used, the increase in property values is $3 billion. As of January 1981, total Alaskan bank loans, Alaskan savings and loan institutions' loans, and Alaska Housing Finance Corporation (AHFC) mortgages were approximately $2.5 billion or 15% of assessed value. Thus, 15% of $3 billion or $450 million would be the increase in borrowers' financial wealth. This is a conservative estimate of the transfer of wealth to owners of Alaskan property (not all to whom would be Alaskans) since many bank and S & L loans are resold to outside banks or mortgage companies and are not on the books as assets of Alaskan banks or S and L's.

The effect of inflation on lenders is to see their loans and fixed-rate investments in the money or bond markets decrease in value by the amount of the gasline-caused inflation. This can be roughly estimated as follows:

Alaskan bank, S&L, and credit union deposits December, 1980	$2,794,555,000
State Appropriations to Loan Programs FY 81 and FY 82	1,560,700,000
TOTAL SAVINGS AND/OR LENDING	$4,355,255,000

Inflation of 18.06% will reduce the value of these funds saved or lent by $786 million. Again, not all of these funds are provided by Alaska residents; some are from outside corporations.

V. ALASKA'S CAPACITY FOR INVOLVEMENT IN ANGTS FINANCING

The analysis performed for determining economic benefits can also be used to answer the questions how much surplus general funds might the state have to invest in ANGTS or how much would its Sadlerochit gas royalties be worth if used to assist in financing. The increasingly dismal outlook for oil prices, at least in the short run, means that the amounts estimated in this analysis are probably too high. At least, this would be the case with general funds of which there could possibly be no surplus in the next few years.

General Funds

A budget forecasting model was used to estimate the previously discussed effects of ANGTS on state government. The model calculated general fund balances out to FY 98 for six scenarios obtained by combinations of

1) no gasline, gasline with low inflation, gasline with high inflation;

2) FY 82 level of service budgets, budgets at the spending limit.

The model was also run an additional six times for each of the cases with the assumption that all funds in excess of the above budget levels were spent on capital projects. 12/

In all cases, the amounts available for capital projects were in excess of the currently anticipated capital budgets for each year from FY 84 to FY 88 by almost one billion dollars or more. For FY 83 all available funds are budgeted. (Compare Table XVIII to the computer runs.)

In total, the amounts available for capital during the period FY 83-98 are over $25 billion in FY 83 dollars in the worst case. The total capital projects for the period, including the best available estimates for Susitna and the capital move, are only $19 billion in as-spent dollars. Of course, capital budgets have not been formulated beyond the Governor's six-year plan as yet.

12/ The amounts so spent on capital projects are substantially less than the cumulative general fund balances in the first six runs due to the loss of interest earnings. Involvement in gasline financing would presumably earn interest, somewhat augmenting the amounts available.

Royalties

A Division of Petroleum Revenue computer model was used to forecast gasline revenues to FY 2016. Three cases were projected based on:

1) Sadlerochit gas prices at the Natural Gas Policy ACT (NGPA) ceiling;

2) netback gas prices based on the two ANGTS construction costs scenarios described earlier;

The present value in 1982 $ of the royalties calculated in these three scenarios is:

1) $2,174.6 million at the NGPA ceiling;

2) $1,594.3 million in the low inflation-centerpoint construction cost (30% overrun) case;

3) $1,474.0 million in the high inflation--10% over centerpoint construction cost (40% overrun) case.

The royalty amounts are discounted at 9% for inflation and 3% for a real rate of return to obtain their present value. Gas prices had been escalated at 8%.

Table I
Present Value of Net Economic Benefits to Alaska
of the Alaska Natural Gas Transportation System
(MILLIONS 1982 $)

	LOW INFLATION SCENARIO				HIGH INFLATION SCENARIO			
	FY 82 Level of Service Budgets		Budgets at Spending Limit		FY 82 Level of Service Budgets		Budgets at Spending Limit	
Benefits (Costs) Discounted @ 3%								
a) State Government		3375.5		3250.1		(2198.6)		(1038.0)
(1) FY 98 General Fund Balance Increase (Decrease) from Base Case	1641.0		1515.6		(3280.5)		(2119.9)	
(2) FY 98 Permanent Fund Balance (Decrease) from Base Case	(21.9)		(21.9)		(534.0)		(534.0)	
(3) FY 99-2016 Gas Revenues	1325.5		1325.5		1344.4		1344.4	
(4) FY 86-2016 Reduced Oil Recovery	501.6		501.6		501.6		501.6	
(5) Gas Revenues from Other Fields	?		?		?		?	
(6) Erosion of Other State Assets due to Gasline Inflation (Retirement Funds, Rainy Day Fund)	(70.7)		(70.7)		(230.1)		(230.1)	
b) Local Government		112.0		112.0		112.0		112.0
c) Private Sector		1118.4		1118.4		1118.4		1118.4
Present Value of Net Economic Benefits (Costs)		4605.9		4480.5		(968.2)		192.4

NOTES:

a) (1) & (2) Amounts from Table II discounted 3% per annum from 1998-1982

(3) Annual amounts from Division of Petroleum Revenue computer runs discounted at 9% inflation and 3% for real rate of return

(4) Net difference in Sadlerochit oil recovery (see footnote a) (4) from Table II) discounted at 3% real rate of return and multiplied by $20 per barrel in 1982 $ and 30% state share

(6) Amount from Table II

b) Amounts from Col. 5, Table XXII discounted at 3% real rate of return to 1982 and escalated at 9% inflation to 1982

c) Amounts from Col. 3, Table XXI discounted at 3% real rate of return to 1982 and escalated at 9% inflation to 1982

Table II
Net Economic Benefit to Alaska
of the Alaska Natural Gas Transportation System
(Millions 1982 $)

	LOW INFLATION SCENARIO		HIGH INFLATION SCENARIO	
Benefits (Costs) not Discounted	FY 82 Level of Service Budgets	Budgets at Spending Limit	FY 82 Level of Service Budgets	Budgets at Spending Limit
a) State Government	4161.0	3959.8	(4682.0)	(2819.5)
(1) FY 98 General Fund Balance Increase (Decrease) from Base Case	2633.3	2432.1	(5264.3)	(3401.8)
(2) FY 98 Permanent Fund Balance (Decrease) from Base Case	(35.2)	(35.2)	(854.4)	(854.4)
(3) FY 99-2016 Gas Revenues	2473.6	2473.6	2506.8	2506.8
(4) FY 86-2016 Reduced Oil Recovery	(840.0)	(840.0)	(840.0)	(840.0)
(5) Gas Revenues from Other Fields	?	?	?	?
(6) Erosion of Other State Assets due to Gasline Inflation (Retirement Funds, Rainy Day Fund)	(70.7)	(70.7)	(230.1)	(230.1)
b) Local Government	127.6	127.6	127.6	127.6
c) Private Sector	1233.2	1233.2	1233.2	1233.2
Net Economic Benefit (Cost)	5521.8	5320.6	(3321.2)	(1458.7)

NOTES: a) (1) & (2) FY 98 balances in FY 83 $ from Legislative Finance computer runs discounted at 9% inflation to 1982 $ and further discounted by the additional inflation from Tables IX and X in the gasline scenarios; also includes $70.3 million and $77.7 million in ¢/MCF severance taxes (1982 $) for the low and high inflation scenarios that were omitted from the computer analysis compounded @ 3% real rate of return to FY 98.

(3) Annual amounts from Division of Petroleum Revenue computer runs discounted at 9% inflation to 1982 $

(4) Net difference in Sadlerochit oil recovery from "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980, Table B-1 valued at a constant $20 per barrel in 1982 $ multiplied by an assumed state share of 30%; Berman and Myers work is based on the March 1980 "Three-Dimensional Reservoir Study, Sadlerochit Formation" by Van Poollen.

(6) 1980 fund balances multiplied by additional gasline inflation from Tables IX and X.

b) Sum of Col. 5, Table XXII escalated at 9% per annum to 1982

c) Sum of Col. 3, Table XXI escalated at 9% per annum to 1982

TABLE III
ALASKA REVENUES
ASSUMING NO GAS LINE CONSTRUCTION
($ Millions)

FY	(1) Severance	(2) Royalties	(3) Petroleum Income Tax	(4) Property Tax	(5) Other Tax and License Revenue
82	1718.7	1678.4	713.0	155.0	210.0
83	1819.6	1767.0	304.0	157.0	212.8
84	2214.1	2145.1	360.0	225.0	222.4
85	2616.1	2542.6	373.0	283.1	244.8
86	2970.9	2869.6	400.0	304.2	269.5
87	3420.7	3322.2	430.0	317.9	296.7
88	3179.9	3629.1	460.0	317.9	326.7
89	3540.8	4003.8	490.0	318.0	359.6
90	3386.2	3880.4	520.0	318.0	395.9
91	3138.7	3667.7	550.0	318.0	435.9
92	3061.4	3644.4	580.0	305.0	479.9
93	3095.6	3709.9	610.0	293.0	528.3
94	3092.8	3723.3	640.0	281.0	581.6
95	2740.0	3404.3	670.0	270.0	640.2
96	2572.1	3276.6	700.0	259.0	704.9
97	2771.4	3552.8	730.0	251.0	775.9
98	2799.9	3673.6	730.0	238.0	854.3

NOTES:

1. "Petroleum Revenue Production Forecast", Alaska Department of Revenue, December 1981; amount is total severance from Table 1 less Prudhoe Bay gas production taxes from Table 2.
2. Ibid.; amount is total royalties from Table 1 less Prudhoe Bay gas royalties from Table 2.

3 & 4. Long range computer projections provided by Research Division, Alaska Department of Revenue.

5. FY 82-FY 84 derived from "Revenue Sources", Alaska Department of Revenue, January 1982.
   FY 85-FY 98 escalated at 1% above the inflation rate of 9% used in projecting budget growth with no gasline.

TABLE IV
Alaska Revenues
Assuming Gas Line Construction
Low Inflation
($ Millions)

FY	(1) Severance	(2) Royalties	(3) Petroleum Income Tax	(4) Property Tax	(5) Other Tax and license Revenue
82	1718.7	1678.4	713.0	157.0	211.5
83	1819.6	1767.0	304.0	169.0	219.3
84	2214.1	2145.1	360.0	256.0	240.1
85	2616.1	2542.6	373.0	399.0	298.4
86	2970.9	2869.6	400.0	543.2	352.9
87	3460.7	3322.2	641.5	857.9	359.7
88	3219.9	3629.1	663.0	836.3	367.7
89	3580.8	4003.8	684.6	814.8	389.9
90	3426.2	3916.7	706.1	793.2	418.2
91	3256.9	3847.3	747.3	771.6	453.3
92	3257.3	3965.2	792.3	737.0	495.4
93	3348.7	4149.1	833.7	703.4	544.0
94	3357.0	4196.6	861.2	669.8	598.6
95	3014.3	3915.3	899.3	637.2	658.5
96	2844.4	3829.6	918.6	604.6	724.8
97	3033.1	4148.5	948.2	575.0	797.6
98	3076.6	4317.2	948.1	540.4	878.0

NOTES: 1, 2 & 3. Amounts from Table III plus amounts from Division of Petroleum Revenue computer run projecting gasline revenue based on $27 billion rate base for the Alaska line segment and conditioning plant. Gas wellhead prices are shown in Col. 5, Table VI . ¢/MCF severance added to computer run amounts.

4. FY 82-86 amounts from Col. 1, Table 2 of "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980, escalated 10% per annum to yield nominal dollars.
FY 87-98 amounts from Division of Petroleum Revenue computer run.

5. Amounts from Table VII

TABLE V
Alaska Revenues
Assuming Gas Line Construction
High Inflation
($ Millions)

FY	(1) Severance	(2) Royalties	(3) Petroleum Income Tax	(4) Property Tax	(5) Other Tax and license Revenue
82	1718.7	1678.4	713.0	157.0	211.5
83	1819.6	1767.0	304.0	169.0	219.3
84	2214.1	2145.1	360.0	257.0	240.2
85	2616.1	2542.6	373.0	409.0	299.8
86	2970.9	2869.6	400.0	572.8	359.4
87	3460.7	3322.2	642.7	911.9	367.1
88	3219.9	3629.1	664.2	888.1	372.8
89	3580.8	4003.8	685.7	854.5	393.5
90	3426.2	3880.4	707.2	840.7	420.8
91	3193.1	3736.9	730.0	817.0	455.3
92	3186.3	3839.3	772.4	780.2	497.3
93	3295.9	4051.4	818.4	744.4	545.9
94	3357.0	4196.6	862.0	708.7	600.5
95	3014.3	3915.3	890.1	673.9	660.6
96	2844.4	3829.6	919.3	639.2	727.2
97	3033.1	4148.5	948.9	607.4	800.2
98	3076.6	4317.2	948.9	570.6	880.9

NOTES: 1, 2 & 3. Amounts from Table III plus amounts from Division of Petroleum Revenue computer run projecting gasline revenue based on $29.7 billion rate base for the Alaska line segment and conditioning plant. Gas wellhead prices are shown in Col. 8 of Table VI. ¢/MCF severance added to computer run amounts.

4. FY 82-86 amounts from Col. 1, Table 2 of "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980, escalated at inflation rates in Table X to yield nominal dollars.
FY 87-98 amounts from Division of Petroleum Revenue computer run.

5. Amounts from Table XIII.

TABLE VI
ALASKA NORTH SLOPE GAS PRICES

			LOW INFLATION SCENARIO (CURRENT ANGTS ESTIMATE)			HIGH INFLATION SCENARIO (40% ANGTS OVERRUN)		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
FY	Oil Price ($/MMBtu)	Alaska Gas Wellhead NGPA Price ($/MMBtu)	ANGTS Delivered Unit Cost Base Case ($/MMBtu)	Alaska Gas Wellhead Netback ($/MMBtu)	Alaska Gas Wellhead Netback ($/MCF)	ANGTS Delivered Cost 40% Overrun ($/MMBtu)	Alaska Gas Wellhead Netback ($/MMBtu)	Alaska Gas Wellhead Netback ($/MCF)
80	5.13	1.786						
87	8.79	3.06	15.90	-		17.48	-	-
88	9.49	3.30	15.30	-		16.66	-	-
89	10.25	3.57	14.80	-		15.99	-	-
90	11.07	3.85	14.30	.62	.65	15.65	-	-
91	11.96	4.16	14.00	2.12	2.24	15.15	.97	1.03
92	12.91	4.50	13.80	3.61	3.81	15.11	2.30	2.43
93	13.95	4.86	13.80	4.86	5.13	14.96	3.85	4.06
94	15.06	5.24	-	5.24	5.53	14.68	5.24	5.53
95	16.26	5.66	-	5.66	5.97	15.06	5.66	5.97
96	17.57	6.12	-	6.12	6.46	15.41	6.12	6.46
97	18.97	6.60	-	6.60	6.96	15.91	6.60	6.96
98	20.49	7.13	-	7.13	7.52	15.98	7.13	7.52

NOTES: 1. & 2. Escalated at 8% per annum; 1980 oil value from "Cost of Service for ANGTS", Federal Inspector for ANGTS, October 19, 1981; 1980 NGPA ceiling price from FERC.

3. Interpolated from Chart on page 729 of "Cost of Service for the ANGTS".
4. Col. 2 - Col. 3 + Col. 1
5. Col. 4 x 1.055 MMBtu per MCF for Sadlerochit gas
6. Interpolated in 1980 $ from chart on page 731 of "Cost of Service for the ANGTS"; escalated at 8% per annum for nominal dollars.
7. Col. 2 - Col. 6 + Col. 1
8. Col. 7 x 1.055

Table VII
ALASKA NON-PETROLEUM REVENUES
RESULTING FROM GASLINE CONSTRUCTION
LOW INFLATION
($ Millions)

FY	(1) Corporate Income Taxes of Pipeline Contractors	(2) Other Corporate Income Taxes	(3) Excise Taxes and Licenses	(4) Total Non-Petroleum Revenue
82	1.1	.1	.3	1.5
83	4.8	.7	1.0	6.5
84	9.2	3.2	5.3	17.7
85	26.2	9.6	17.8	53.6
86	33.7	16.3	33.4	83.4
87	21.2	13.1	28.7	63.0
88	1.9	13.5	25.6	41.0
89		12.5	17.8	30.3
90		10.6	11.7	22.3
91		8.4	9.0	17.4
92		7.6	7.9	15.5
93		7.7	8.0	15.7
94		8.2	8.8	17.0
95		8.8	9.5	18.3
96		9.6	10.3	19.9
97		10.4	11.3	21.7
98		11.4	12.3	23.7

Notes: 1. Amounts from Table 2 of "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980, lagged one year to reflect current estimated construction commencement date and escalated 9% plus the additional inflation from Table IX per annum.

2 & 3. Amounts from Table 5 of Berman and Myers lagged one year and escalated as in footnote 1.

4. Col. 1 + Col. 2 + Col. 3.

Table VIII
ALASKA NON-PETROLEUM REVENUES
RESULTING FROM GASLINE CONSTRUCTION
HIGH INFLATION
($ Millions)

FY	(1) Corporate Income Taxes of Pipeline Contractors	(2) Other Corporate Income Taxes	(3) Excise Taxes and Licenses	(4) Total Non-Petroleum Revenue
82	1.1	.1	.3	1.5
83	4.8	.7	1.0	6.5
84	9.3	3.2	5.3	17.8
85	26.9	9.9	18.2	55.0
86	36.3	17.6	36.0	89.9
87	23.7	14.6	32.1	70.4
88	2.1	15.1	28.9	46.1
89		13.9	20.0	33.9
90		11.8	13.1	24.9
91		9.4	10.0	19.4
92		8.5	8.9	17.4
93		8.6	9.0	17.6
94		9.1	9.8	18.9
95		9.8	10.6	20.4
96		10.7	11.6	22.3
97		11.7	12.6	24.3
98		12.8	13.8	26.6

NOTES
1. Amounts from Table 2 of "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980, lagged one year to reflect current estimated construction commencement date and escalated 9% plus the additional inflation from Table X per annum lagged one year for fiscal year basis and delay in payment dates.

2 & 3. Amounts from Table 5 of Berman and Myers lagged one year and escalated as in footnote 1.

4. Col. 1 + Col. 2 + Col. 3

TABLE IX

Impact of Gasline on Alaska Inflation

Low Inflation Estimate

FY	(1) AEIRS CPI No Gasline	(2) AEIRS CPI Gasline	(3) Annual Inflation No Gasline	(4) Annual Inflation with Gasline	(5) Additional Inflation Due to Gasline
81	2.466	2.501	-	-	-
82	2.684	2.751	8.84%	10.00%	-
83	2.919	3.024	8.76	9.92	1.06%
84	3.169	3.318	8.56	9.72	1.07
85	3.445	3.646	8.71	9.89	1.07
86	3.753	4.017	8.94	10.18	1.09
87	-	-	-	-	1.14
88	-	-	-	-	-

NOTES:
1. Projected Anchorage CPI from Table II, "Alaska Economic Information and Reporting System", Alaska Department of Commerce and Economic Development, July, 1980.
2. Projected Anchorage CPI from Table II of a July 10, 1980 run of the AEIRS model simulating gasline construction.

3 & 4. Annual percentage increase in Cols. 1 and 2.

5. (1 + Col. 4/100) ÷ (1 + Col. 3/100) - 1; amounts lagged one year to reflect current estimated construction commencement date.

TABLE X
Impact of Gasline on Alaska Inflation
HIGH INFLATION ESTIMATE

Calendar Year	(1) Alaska Gasline Construction Cost Billions 1980 $	(2) Additional Inflation Due To Gasline	(3) Cumulative Additional Inflation
82	.6	--	--
83	1.2	2%	2.00%
84	3.3	4%	6.08%
85	3.3	6%	12.44%
86	2.4	5%	18.06%
Total	10.8		

Notes:

1. Incremental construction costs for line with 30% overrun for IROR centerpoint interpolated from chart on page 714 of "Cost of Service for the Alaska Natural Gas Transportation System", FERC Federal Inspector for ANGTS, October 19, 1981.

2. Arbitrary estimate of the author.

3. Product of inflation for current year times all previous years.

TABLE XI

IMPACT OF TAPS CONSTRUCTION ON INFLATION

Year	(1) U.S. CPI (October)	(2) U.S. Inflation	(3) Anchorage CPI	(4) Anchorage Inflation	(5) Anchorage vs. U.S. Inflation	(6) Anchorage Inflation During TAPS Construction in Excess of 67-73 Average Margin	(7) Anchorage Inflation Below 67-73 Average Margin Following TAPS Construction
67	101.1		100.0				
68	105.7	4.55%	102.6	2.60%	(1.95%)		
69	111.6	5.59	107.3	4.58	(1.01)		
70	118.1	5.82	111.5	3.91	(1.91)		
71	122.4	3.64	114.4	2.60	(1.04)		
72	126.6	3.43	116.9	2.18	(1.25)		
73	136.6	7.90	123.8	5.90	(2.00)		
74	153.0	12.01	140.0	13.08	1.07	2.60%	
75	164.6	7.58	157.4	12.42	4.84	6.37	
76	173.3	5.29	167.6	6.48	1.19	2.72	
77	184.5	6.46	177.3	5.79	(.67)	.86	
78	200.9	8.89	194.7	9.81	.92	2.45	
79	225.4	12.20	213.7	9.75	(2.45)		(.92%)
80	253.9	12.64	236.5	10.67	(1.97)		(.44)
81	279.9	10.24	253.7	7.27	(2.97)		(1.44)
Average 1967-1973 Margin Below U.S. Inflation					(1.53)		
Cumulative Inflation						15.83%	2.82%

NOTES: Columns 6 and 7 assume that in the absence of TAPS, Anchorage inflation would have been 1.53 percentage points below U.S. inflation.

Table XII
Alaska Population
(000)

FY	(1) Non-Gasline Population	(2) Gasline Construction Population	(3) Conditioning Plant Construction Population	(4) Total Population with Gasline	(5) Population Growth with Gasline
82	425.6	.4	--	426.0	
83	437.7	3.7	.5	441.9	3.73%
84	450.1	17.6	1.9	469.6	6.27
85	462.9	35.3	3.6	501.8	6.86
86	476.0	31.1	3.2	510.3	1.69
87	489.6	19.1	1.9	510.6	--
88	503.5			503.5	(1.39)
89	517.8			517.8	2.84
90	532.5			532.5	2.84
91	547.6			547.6	2.84
92	563.1			563.1	2.84
93	579.1			579.1	2.84
94	595.6			595.6	2.84
95	612.5			612.5	2.84
96	629.9			629.9	2.84
97	647.8			647.8	2.84
98	666.2			666.2	2.84

NOTES:
1. FY 82 = July 1, 1981 population from "July 1, 1981 Population, Municipalities and Census Areas", Department of Community and Regional Affairs escalated at one-half the average compound growth rate between the 1970 and 1980 census which was 2.84%;
   FY 82 and beyond = prior year population x 1.0284
2. Population 3.B from Table II of "The Relationship between the Alaska Natural Gas Pipeline and State and Local Government Expenditures", Institute of Social and Economic Research, December 1980 divided by pipeline construction employment in Table 2 of ISER lagged one year and multiplied by estimated pipeline construction employment in Table II-1 of "Gasline Planning Update", Northwest Alaska Pipeline Company, September 1981; figures include direct, indirect, and government spending induced employment impact and employees' families.
3. Same ratio as footnote 2 multiplied by direct employment on conditioning plant construction interpolated from Table VI-2 of "Gasline Planning Update" til peak construction year of FY 85. Population declines thereafter at same rate as Col. 2.
4. Col. 1 + Col. 2 + Col. 3
5. Annual percentage increase in Col. 4

TABLE XIII
State of Alaska
Nominal General Fund Budget Growth at the Level Permitted by the Proposed Constitutional Spending Limit

FY	(1) NO GASLINE	(2) GASLINE LOW INFLATION	(3) GASLINE HIGH INFLATION
83	12.10%	14.26%	15.33%
84	12.10	17.07	20.47
85	12.10	17.72	23.47
86	12.10	12.05	12.11
87	12.10	10.24	9.00
88	12.10	7.48	7.48
89-90, annually	12.10	12.10	12.10

NOTES:

1. Annual inflation at 9% x average population growth of 2.84% between 1970 and 1980 census.
2. Population growth from Col. 5, Table XII x annual inflation of 9% x additional inflation due to gasline from Col. 5, Table IX
3. Population growth from Col. 5, Table XII x annual inflation of 9% x additional inflation from Col 2, Table X

TABLE XIV
State of Alaska
Nominal General Fund Budget Growth Required to Maintain FY 82 Level of Service

	(1)	(2)	(3)	(4)	(5)	(6)
	NO GASLINE		GASLINE LOW INFLATION		GASLINE HIGH INFLATION	
FY	Operating	Capital	Operating	Capital	Operating	Capital
83	11.36%	11.70%	13.21%	13.31%	14.26%	14.36%
84	"	"	15.09	14.51	18.43	17.83
85	"	"	15.53	14.78	21.17	20.38
86	"	"	11.73	12.38	16.05	16.73
87	"	"	10.53	11.64	9.28	10.38
88	"	"	8.28	9.74	8.28	9.74
89-98, annually	11.36%	11.70%	11.36	11.70	11.36	11.70

NOTES:
1. & 2. Real growth rates from Cols. 1 and 2, Table XVI x 9% annual inflation
3. & 4. Real growth rates from Cols. 3 and 4, Table XVI x 9% annual inflation x additional inflation due to gasline from Col. 5, Table IX
5. & 6. Real growth rates from Cols. 3 and 4, Table XVI x 9% annual inflation x additional inflation due to gasline from Col. 2, Table X

TABLE XV
STATE OF ALASKA
HIGHWAY COST IMPACT OF THE GASLINE
($ MILLIONS)

FY	Original Cost Estimate (Nominal $)	Original Cost Estimate (1980 $)	Low Inflation Cost Estimate (Nominal $)	High Inflation Cost Estimate (Nominal $)
82	8.4	6.9	-	-
83	25.7	19.3	9.1	9.3
84	31.1	21.2	28.3	29.3
85	31.0	19.2	34.1	37.0
86	207.1	116.7	34.0	38.2
87	-	-	227.4	253.0
TOTAL	303.3	183.3	332.9	366.8

NOTES:

1. Amounts from July 21, 1980 letter from Commissioner Robert Ward of the Alaska Department of Transportation and Public Facilities to Al Kuhn of Northwest Alaskan Pipeline Company.

2. FY 82-85: amount from Co. 1 discounted at 10% per annum, the inflation rate assumed in Commissioner Ward's letter.
   FY 86: amount from Commissioner Ward's letter

3. Col. 2 inflated at 10% per annum to succeeding year to reflect current estimated construction commencement date.

4. Col. 2 inflated at 9% per annum plus additional inflation from Table X to succeeding year.

TABLE XVI
STATE OF ALASKA
REAL GENERAL FUND BUDGET GROWTH REQUIRED TO MAINTAIN FY 82 LEVEL OF SERVICE PER CAPITA

	(1)	(2)	(3)	(4)
	No Gasline		Gasline	
FY	Operating	Capital	Operating	Capital
83	2.17%	2.48%	2.77%	2.86%
84	2.17%	2.48%	4.47%	3.94%
85	2.17%	2.48%	4.87%	4.19%
86	2.17%	2.48%	1.40%	1.99%
87	2.17%	2.48%	.26%	1.27%
88	2.17%	2.48%	(.66)%	.68%
89-98, annually	2.17%	2.48%	2.17%	2.48

NOTES:

1. 2.84% population growth (see Footnote 1, Table XII) x .764 which is the proportion of the general fund operating budget estimated to be population sensitive in Table 5 of ISER study (mentioned in Footnote 2, Table XII); this includes a percentage for government support activities in the same ratio as directly population sensitive programs are to the total general fund budget; it also includes population sensitive programs outside the impact area from Table B.1 of ISER.

2. 2.84 population growth x .872 which is the proportion of the general fund and general obligation bond capital budget estimated to be population sensitive in Table B.3 of ISER; this growth rate is to be applied to one-twentieth of the total capital stock in Col. 5, Table XVII adjusted for inflation at 9% over a three year construction period, a factor of 1.2.

3. No gasline growth rate from Col. 1 x (additional gasline growth rate, ((1 + Col. 5, Table XII)/1.0284)-1, x .735 population sensitive operating budget in impact areas derived from ISER Table 5 x .919 to reflect different age and family structure of migrants); .919 is derived from Table B.2 and Table 5 of ISER by comparing the total population sensitive general fund budget per capita to the cost per capita calculated for migrants.

4. No gasline growth rate from Col. 2 x (additional gasline growth rate, ((1 + Col. 5, Table XII)/1.0284)-1, x .465 population sensitive non-highway impact area capital budget estimated from Table B.3 of ISER x .917 to reflect different age and family structure of migrants); .917 is derived from Table B.4 of ISER; this growth rate is to be applied to one-twentieth of the non-highway capital stock in Col. 10, Table XVII adjusted for inflation (see Footnote 2).

TABLE XVIII
STATE OF ALASKA
STATE-FUNDED CAPITAL STOCK IN MILLIONS OF FY 82 $

	TOTAL					NON-HIGHWAY				
FY	(1) Gen.Fund Capital Approp.	(2) G.O.Bond Authorizations	(3) Annual Projects Completed	(4) Value of Projects Completed	(5) Value of Cap.Stock FY 82 $	(6) Gen.Fund Capital Approp.	(7) G.O.Bond Authorizations	(8) Annual Projects Completed	(9) Value of Projects Completed	(10) Value of Cap.Stock FY 82 $
63	6.8					2.0				
64	8.2	7.0				2.8	7.0			
65	.9					.9				
66	2.0	62.6	6.8	25.2		1.8	52.1	2.0	7.4	
67	1.3	13.2	15.2	53.6		1.3	8.2	9.8	34.6	
68	1.8	44.7	.9	3.0		1.8	33.5	.9	3.0	
69	2.3		64.6	200.7		2.2		53.9	167.5	
70	2.0	146.2	14.5	42.1		2.0	111.5	9.5	27.6	
71	61.2		46.5	125.7		57.5		35.3	95.4	
72	8.4	124.5	2.3	5.9		8.4	114.5	2.2	5.6	
73	11.6		148.2	345.3		10.5		113.5	264.5	
74	7.5	189.5	61.2	125.4		7.4	152.2	57.5	117.8	
75	12.4		132.9	248.6		11.1		122.9	229.9	
76	16.2	201.1	11.6	20.9		14.8	150.0	10.5	18.9	
77	10.9		197.0	325.1		10.1		159.6	263.4	
78	29.8	271.3	12.4	18.2		27.3	188.4	11.1	16.3	
79	138.9		217.3	281.4		137.7		164.8	213.4	
80	100.6	289.7	10.9	12.9		89.9	206.1	10.1	12.0	
81	707.4		301.1	328.2		622.2		215.7	235.1	
82	1380.0	-	138.9	138.9		1287.9		137.7	137.7	
83			390.3	358.1				296.0	271.6	
84			707.4	595.4				622.2	523.7	
85			1380.0	1065.6	3175.5			1287.9	994.5	2728.0

NOTES: 1. FY 63-79 amounts from general appropriations act plus Ch. 134 for FY 79. FY 80-82 amounts from "Alaska Budget in Brief, FY 82," Division of Budget & Management.

2. Amounts from "Annual Financial Report" State of Alaska, various years.

3. Col. 1 and Col. 2 lagged three years.

4. Col. 3 x Department of Commerce Construction Index derived from Table 13 of the ISER study (mentioned in Footnote 2, Table XII) adjusted to FY 82 $ assuming 9% annual inflation for FY 80-85.

5. This is what the value of all projects would be in FY 82 $ upon completion of all authorized projects in FY 85 after depreciating each year's projects over a 20 year period.

6. Amounts for highways from "Annual Financial Report," State of Alaska, various years and "Free Conference Committee Report, Operating and Capital Budget" Alaska Legislature, various years and Session Laws of Alaska, various years, are deducted from Col. 1.

7. Col. 2 less amounts for highways bond issues from "Annual Financial Report," State of Alaska, various years.

8. Col. 6 and Col. 7 lagged three years

9. Same method as Footnote 4.

10. Same method as Footnote 5.

TABLE XVIII
State of Alaska
Capital Projects
($ Millions)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		HYDROELECTRIC PROJECTS						
				SUSITNA				
FY	Governor's Six-year Capital Budget	Licensed or under Construction	West Creek Bradley Lake Taximina	Watana	Devil Canyon	Total Hydro	Capital City Relocation	Total Capital Projects
83	1156.0	228.0	200.0	25.6		453.6	-	1609.6
84	1819.4		200.0	50.0		250.0	13.4	2082.8
85	981.8		180.0	220.0		400.0	64.0	1445.8
86	782.9		160.0	490.0		650.0	120.8	1553.7
87	1001.2			600.0		600.0	110.7	1711.9
88	1106.2			750.0		750.0	143.4	1999.6
89				900.0		900.0	120.5	1020.5
90				1000.0		1000.0	150.9	1150.9
91				750.0		750.0	97.6	847.6
92				610.0		610.0	153.0	763.0
93				460.0	480.0	940.0	172.5	1112.5
94					610.0	610.0	145.7	755.7
95					760.0	760.0	120.8	880.8
96					830.0	830.0	134.5	964.5
97					900.0	900.0	88.9	988.9
98					860.0	860.0	39.8	899.8
TOTAL	6847.5			5855.6		11263.6	1676.5	19787.6

NOTES: 1. Computer total of general fund (including voter approval) projects contained in "Executive Budget, Book 2-Capital Budget and Six Year Capital Program, FY 83", Jay Hammond, Governor, provided by Budget and Management.
2. Figure provided by Alaska Power Authority.
3 & 4. Figures provided by Alaska Power Authority; assumes 9% inflation; costs not yet definitive; project feasibility uncertain; Watana costs $3.5 billion in January 1982 $
5. According to Alaska Power Authority, Devil Canyon will cost $1.55 billion in January 1982 $ and would be constructed over a seven year period beginning sometime between 1990 and 1996; scheduled appropriations in Col. 5 estimated by comparison to Watana schedule in January 1982 $
6. Sum of Col. 2 thru 5
7. Amounts from a table on pages 82 and 83 of "Financial Plan and Detailed Economic Projections, Background Report No. 9", Capital Site Planning Commission, March 1978 which are in 1978 dollars have been inflated at 9% per annum and lagged four years; figures are net of land sales and developers costs and represent state and municipal investment exclusive of any financing costs.

COMMENT: These amounts have not been appropriated; appropriation of these amounts may depend on future levels of state revenue.

TABLE XIX
Alaska Personal Income
Resulting from Gasline Impact
(Millions 1980 $)

FY	(1) Wages	(2) Gasline Construction Corporate Profits	(3) Corporate Profits From Indirect Gasline Impact	(4) Personal Income From Gasline Impact
82	13.9	5.3	1.1	20.3
83	171.9	21.2	6.4	199.5
84	593.1	37.2	25.5	655.8
85	1115.8	95.7	70.2	1281.7
86	980.9	111.7	108.5	1201.1
87	591.3	63.8	78.7	733.8

Notes:

1. Amount from Col. 8, Table XX
2. Income taxes of pipeline contractors from Table 2 "Estimated State and Local Revenue from the Alaska Highway Natural Gas Pipeline Project", Berman and Myers, October 1980 ÷ .094 Alaska tax rate x 50% rough assumption of Alaskan-owned businesses' share of contracts; amounts lagged one year for construction commencement.
3. Income taxes from Table 5 of Berman and Myers ÷ .094; lagged one year.
4. Sum of Cols. 1 through 3

TABLE XX
Alaska Employment and Wages
Resulting from Gasline Impact

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	EMPLOYMENT				WAGES (Millions 1980 $)			
	CONSTRUCTION				CONSTRUCTION			
FY	Staff	Craft	Other	Total	Staff	Craft	Other	Total
82	220	32	134	386	8.3	1.9	3.7	13.9
83	1290	1072	2185	4547	48.5	63.0	60.4	171.9
84	2859	4216	8607	15682	107.4	247.9	237.8	593.1
85	3607	7805	18875	30287	135.5	458.9	521.4	1115.8
86	1957	5255	21660	28872	73.5	309.0	598.4	980.9
87	314	378	20172	20864	11.8	22.2	557.3	591.3

NOTES:

1. & 2. Ratio of staff and craft to total pipeline construction employment as contained in Table 2, "The Relationship Between the Alaska Natural Gas Pipeline and State and Local Government Expenditures", Goldsmith and Mogford, ISER, December 1980, applied to estimated pipeline and conditioning plant construction contained in Tables II-1 and VI-2 of "Gasline Planning Update", Northwest Alaskan Pipeline Company, December 1980; ratio lagged one year;

3. Col. 4 less Cols. 1 and 2;
4. Ratio of Col. 4 to Col. 1 on page A-11 of "ISER" x sum of Col. 1 and Col. 2 above, ratio lagged one year; includes state government employment;
5. Average salary of $37,650 as calculated on page A-6 of "ISER" x Col. 1;
6. Average wage of $20 per hour for 70 hour weeks for 42 weeks per year as calculated on pages A-5 and A-7 of "ISER" x Col. 2;
7. Col. 3 x average weekly earnings for non-government and non-service employment for November 1980 of $531.27 as calculated from February 1981 and 1982 issues of "Alaska Economic Trends", Alaska Department of Labor, x 52;
8. Sum of Cols. 5 through 7.

TABLE XXI
PRIVATE SECTOR ECONOMIC BENEFIT
FROM GASLINE IMPACT
(MILLIONS 1980 $)

FY	(1) Wage Gains of Alaska Residents	(2) Corporate Profits	(3) Total Benefits
82	1.9	6.4	8.3
83	27.9	27.6	55.5
84	96.1	62.7	158.8
85	167.7	165.9	333.6
86	110.1	220.2	330.3
87	9.0	142.5	151.5

NOTES:

1. This assumes only pipeline employees experience a gain in wages in real dollars. It assumes that 60% of pipeline jobs go to Alaska residents, based on a review of the TAPS experience in "The Relationship Between the Alaska Natural Gas Pipeline and State and Local Government Experiences," Goldsmith and Mogford, ISER, December 1980. The gain in wages is calculated on the basis of wage rates in footnotes 5, 6, and 7 of Table XX applied to 60% of the employment in Cols. 1 and 2 of Table XX

2. Sum of Cols. 2 and 3 from Table XIX

3. Sum of Cols. 1 and 2.

TABLE XXII
Alaska Local Government
Revenues and Expenditures
from Gasline Impact
(Millions 1980 $)

FY		(1) Additional Revenue	(2) Additional Expenditures Operating	(3) Additional Expenditures Capital	(4) Additional Expenditures Total	(5) Surplus (Deficit)
82		.3	.1	--	.1	.2
83		2.1	1.5	.3	1.8	.3
84		7.2	6.9	1.4	8.3	(1.1)
85		25.6	13.8	2.8	16.6	9.0
86		62.8	12.1	2.5	14.6	48.2
87		59.7	7.4	1.5	8.9	50.8
	TOTAL	157.7	41.8	8.5	50.3	107.4

Notes:

1. Sum of Col. 5, Table 3 and Col. 6, Table 5 of "Estimated State and Local Revenue from the Alaska Natural Gas Pipeline Project", Berman and Myers, October 1980; amounts include direct and indirect effects of gasline construction on local property and sales taxes;
2. Estimated calendar 1979 expenditures per migrant of $353.70 per annum in 1980 $ from "The Relationship Between the Alaska Natural Gas Pipeline and State and Local Government Expenditures", Goldsmith and Mogford, ISER, December 1980, multiplied by the sum of gasline and conditioning plant construction-related population increases from Cols. 2 and 3 of Table XII;
3. Expenditures of $72.28 per migrant required to maintain 1979 level of local government fixed assets as estimated by Goldsmith and Mogford multiplied by population impact as in footnote 2.
4. Col. 2 + Col. 3.
5. Col. 1 - Col. 4.

APPENDIX A

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

1

13-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	402.0	4220.7	1830.2	212.8	113.2	152.5	2308.6	1912.0	4771.9	1218.6	0.0
1984	4630.3	762.4	5392.7	2038.1	237.7	138.8	162.3	2576.9	2815.8	5606.2	4034.5	0.0
1985	5424.0	1306.9	6730.9	2269.6	265.5	163.8	231.8	2930.7	3800.1	6505.0	7834.6	0.0
1986	6096.8	1969.6	8066.4	2527.5	296.6	161.9	300.6	3286.5	4779.8	7459.1	12614.4	0.0
1987	6957.0	2764.1	9721.1	2814.6	331.3	157.8	367.2	3670.9	6050.2	8513.6	18664.6	0.0
1988	7006.3	3646.9	10653.2	3134.3	370.0	154.8	423.6	4082.8	6570.4	9664.3	25235.0	0.0
1989	7698.8	4646.7	12345.5	3490.4	413.3	146.5	485.0	4535.2	7810.3	10944.2	33045.3	0.0
1990	7504.1	5757.4	13261.5	3886.9	461.7	135.4	551.3	5035.3	8226.2	12218.7	41271.5	0.0
1991	7172.2	6919.8	14092.0	4328.5	515.7	114.8	621.6	5580.5	8511.5	13454.1	49783.0	0.0
1992	7095.9	8138.5	15234.4	4820.2	576.0	114.1	694.8	6205.2	9029.2	14730.3	58812.2	0.0
1993	7219.3	9444.5	16663.8	5367.7	643.4	31.7	770.5	6813.3	9850.5	16053.9	68662.6	0.0
1994	7272.1	10847.3	18119.4	5977.5	718.7	25.8	847.6	7569.7	10549.8	17413.3	79212.4	0.0
1995	6746.5	12301.6	19048.0	6656.6	802.8	23.0	925.4	8407.7	10640.3	18707.8	89852.7	0.0
1996	6541.8	13786.4	20328.2	7412.7	896.7	21.5	1003.5	9334.5	10993.7	19993.6	100846.4	0.0
1997	6984.4	15357.4	22341.8	8254.8	1001.7	16.7	1082.7	10355.8	11985.9	21377.2	112832.3	0.0
1998	7159.9	17038.1	24198.0	9192.6	1118.8	14.4	1163.3	11489.1	12708.9	22839.6	125541.2	0.0

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

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13-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	402.0	4220.7	1830.2	212.8	113.2	152.5	2308.6	1912.0	4771.9	1218.6	0.0
1984	4248.0	699.5	4947.5	1869.8	218.1	127.3	148.9	2364.1	2583.3	5143.3	3701.3	0.0
1985	4565.2	1100.0	5665.2	1910.3	223.5	137.9	195.1	2466.7	3198.5	5475.1	6594.2	0.0
1986	4707.8	1520.9	6228.7	1951.7	229.0	125.0	232.1	2537.8	3690.9	5759.8	9740.7	0.0
1987	4928.5	1958.2	6886.6	1993.9	234.7	111.8	260.1	2600.6	4286.1	6031.2	13222.5	0.0
1988	4553.6	2370.2	6923.9	2037.1	240.5	100.6	275.3	2653.5	4270.3	6281.1	16401.0	0.0
1989	4590.5	2770.7	7361.2	2081.2	246.5	87.4	289.2	2704.2	4657.0	6525.7	19703.8	0.0
1990	4105.0	3149.5	7254.5	2126.3	252.6	74.1	301.6	2754.5	4500.0	6684.0	22576.9	0.0
1991	3599.5	3472.8	7072.3	2172.3	258.8	57.6	311.9	2800.7	4271.6	6752.1	24984.4	0.0
1992	3267.1	3747.2	7014.3	2219.3	265.2	52.5	319.9	2857.0	4157.3	6782.2	27078.8	0.0
1993	3049.5	3989.5	7039.0	2267.4	271.8	13.4	325.5	2878.0	4161.0	6781.3	29003.8	0.0
1994	2818.2	4203.7	7021.9	2316.5	278.5	10.0	328.5	2933.5	4088.4	6748.2	30697.4	0.0
1995	2398.6	4373.6	6772.2	2366.6	285.4	8.2	329.0	2989.2	3783.0	6651.3	31945.8	0.0
1996	2133.8	4496.8	6630.6	2417.9	292.5	7.0	327.3	3044.7	3585.9	6521.5	32893.9	0.0
1997	2090.1	4595.6	6685.7	2470.2	299.7	5.0	324.0	3099.0	3586.7	6397.1	33764.7	0.0
1998	1965.7	4677.6	6643.3	2523.7	307.2	4.0	319.4	3154.2	3489.1	6270.3	34465.8	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	157.0	212.8	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	225.0	222.4	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	283.1	244.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	304.2	269.5	2,869.6	0.0
1987	81.9	0.0	3,420.7	430.0	317.9	296.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	460.0	317.9	326.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	490.0	318.0	359.6	3,954.0	49.8
1990	59.5	0.0	3,386.2	520.0	318.0	395.9	3,793.3	78.1
1991	38.9	0.0	3,138.7	550.0	318.0	435.9	3,582.9	84.8
1992	38.2	0.0	3,061.4	580.0	305.0	479.9	3,389.4	255.0
1993	31.7	0.0	3,095.6	610.0	293.0	528.3	3,349.8	360.1
1994	25.8	0.0	3,092.8	640.0	281.0	581.6	3,260.1	463.2
1995	23.0	0.0	2,740.0	670.0	270.0	640.2	2,896.5	507.8
1996	21.5	0.0	2,572.1	700.0	259.0	704.9	2,670.0	606.6
1997	16.7	0.0	2,771.4	730.0	251.0	775.9	2,778.8	744.0
1998	14.4	0.0	2,799.9	730.0	238.0	854.3	2,803.6	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
OPERATING BUDGET GROWTH RATE	=	0.114
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
CAPITAL BUDGET GROWTH RATE	=	0.117
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

13-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	392.4	4211.0	1830.2	1421.8	113.2	152.5	3517.6	693.4	4771.9	0.0	0.0
1984	4630.3	671.9	5302.2	2038.1	2963.0	138.8	162.3	5302.2	0.0	5606.2	0.0	0.0
1985	5424.0	988.7	6412.7	2269.6	3747.5	163.8	231.8	6412.7	0.0	6505.0	0.0	0.0
1986	6096.8	1252.3	7349.1	2527.5	4359.1	161.9	300.6	7349.1	0.0	7459.1	0.0	0.0
1987	6957.0	1490.7	8447.7	2814.6	5108.0	157.8	367.2	8447.7	-0.0	8513.6	0.0	0.0
1988	7006.3	1667.8	8674.1	3134.3	4961.4	154.8	423.6	8674.1	0.0	9664.3	0.0	0.0
1989	7698.8	1829.4	9528.2	3490.4	5406.3	146.5	485.0	9528.2	-0.0	10944.2	0.0	0.0
1990	7504.1	1971.8	9476.0	3886.9	4902.3	135.4	551.3	9476.0	0.0	12218.7	0.0	0.0
1991	7172.2	2060.4	9232.5	4328.5	4167.7	114.8	621.6	9232.5	0.0	13454.1	0.0	0.0
1992	7095.9	2127.7	9223.5	4820.2	3594.4	114.1	694.8	9223.5	-0.0	14730.3	0.0	0.0
1993	7219.3	2219.8	9439.1	5367.7	3269.2	31.7	770.5	9439.1	-0.0	16053.9	0.0	0.0
1994	7272.1	2326.5	9598.6	5977.5	2747.6	25.8	847.6	9598.6	0.0	17413.3	0.0	0.0
1995	6746.5	2392.0	9138.5	6656.6	1533.6	23.0	925.4	9138.5	0.0	18707.8	0.0	0.0
1996	6541.8	2439.4	8981.2	7412.7	896.7	21.5	1003.5	9334.5	-353.3	19993.6	0.0	353.3
1997	6984.4	2553.1	9537.5	8254.8	1001.7	16.7	1082.7	10355.8	-818.4	21377.2	0.0	818.4
1998	7159.9	2735.7	9895.6	9192.6	1118.8	14.4	1163.3	11489.1	-1593.5	22839.6	0.0	1593.5

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

13-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	392.4	4211.0	1830.2	1421.8	113.2	152.5	3517.6	693.4	4771.9	0.0	0.0
1984	4248.0	616.4	4864.4	1869.8	2718.4	127.3	148.9	4864.4	0.0	5143.3	0.0	0.0
1985	4565.2	832.2	5397.4	1910.3	3154.2	137.9	195.1	5397.4	0.0	5475.1	0.0	0.0
1986	4707.8	967.0	5674.8	1951.7	3366.0	125.0	232.1	5674.8	0.0	5759.8	0.0	0.0
1987	4928.5	1056.1	5984.5	1993.9	3618.7	111.8	260.1	5984.5	-0.0	6031.2	0.0	0.0
1988	4553.6	1084.0	5637.6	2037.1	3224.5	100.6	275.3	5637.6	0.0	6281.1	0.0	0.0
1989	4590.5	1090.8	5681.4	2081.2	3223.6	87.4	289.2	5681.4	-0.0	6525.7	0.0	0.0
1990	4105.0	1078.7	5183.7	2126.3	2681.7	74.1	301.6	5183.7	0.0	6684.0	0.0	0.0
1991	3599.5	1034.0	4633.5	2172.3	2091.6	57.6	311.9	4633.5	0.0	6752.1	0.0	0.0
1992	3267.1	979.6	4246.8	2219.3	1655.0	52.5	319.9	4246.8	-0.0	6782.2	0.0	0.0
1993	3049.5	937.7	3987.2	2267.4	1380.9	13.4	325.5	3987.2	-0.0	6781.3	0.0	0.0
1994	2818.2	901.6	3719.8	2316.5	1064.8	10.0	328.5	3719.8	0.0	6748.2	0.0	0.0
1995	2398.6	850.5	3249.1	2366.6	545.2	8.2	329.0	3249.1	0.0	6651.3	0.0	0.0
1996	2133.8	795.7	2929.5	2417.9	292.5	7.0	327.3	3044.7	-115.2	6521.5	0.0	115.2
1997	2090.1	764.0	2854.1	2470.2	299.7	5.0	324.0	3099.0	-244.9	6397.1	0.0	244.9
1998	1965.7	751.0	2716.7	2523.7	307.2	4.0	319.4	3154.2	-437.5	6270.3	0.0	437.5

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	157.0	212.8	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	225.0	222.4	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	283.1	244.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	304.2	269.5	2,869.6	0.0
1987	81.9	0.0	3,420.7	430.0	317.9	296.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	460.0	317.9	326.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	490.0	318.0	359.6	3,954.0	49.8
1990	59.5	0.0	3,3[illegible].2	520.0	318.0	395.9	3,793.3	78.1
1991	38.9	0.0	3,138.7	550.0	318.0	435.9	3,582.9	84.8
1992	38.2	0.0	3,061.4	580.0	305.0	479.9	3,389.4	255.0
1993	31.7	0.0	3,095.6	610.0	293.0	528.3	3,349.8	360.1
1994	25.8	0.0	3,092.8	640.0	281.0	581.6	3,260.1	463.2
1995	23.0	0.0	2,740.0	670.0	270.0	640.2	2,896.5	507.8
1996	21.5	0.0	2,572.1	700.0	259.0	704.9	2,670.0	606.6
1997	16.7	0.0	2,771.4	730.0	251.0	775.9	2,778.8	744.0
1998	14.4	0.0	2,799.9	730.0	238.0	854.3	2,803.6	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
OPERATING BUDGET GROWTH RATE	=	0.114
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
CAPITAL BUDGET GROWTH RATE	=	0.117
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

15-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	394.9	4213.5	1866.7	933.3	113.2	152.5	3065.6	1147.9	4771.9	454.5	0.0
1984	4630.3	708.1	5338.4	2092.6	1046.2	138.8	162.3	3439.9	1898.5	5606.2	2353.0	0.0
1985	5424.0	1157.4	6581.4	2345.8	1172.8	163.8	231.8	3914.2	2667.2	6505.0	5020.2	0.0
1986	6096.8	1682.8	7779.6	2629.6	1314.7	161.9	300.6	4406.8	3372.7	7459.1	8392.9	0.0
1987	6957.0	2305.8	9262.8	2947.8	1473.8	157.8	367.2	4946.7	4316.1	8513.6	12709.0	0.0
1988	7006.3	2976.3	9982.6	3304.5	1652.1	154.8	423.6	5535.1	4447.5	9664.3	17156.5	0.0
1989	7698.8	3715.2	11414.0	3704.3	1852.1	146.5	485.0	6187.9	5226.1	10944.2	22382.6	0.0
1990	7504.1	4507.1	12011.3	4152.5	2076.2	135.4	551.3	6915.4	5095.8	12218.7	27478.4	0.0
1991	7172.2	5282.4	12454.6	4655.0	2327.4	114.8	621.6	7718.8	4735.8	13454.1	32214.3	0.0
1992	7095.9	6033.0	13128.8	5218.3	2609.0	114.1	694.8	8636.2	4492.6	14730.3	36706.9	0.0
1993	7219.3	6775.3	13994.6	5849.7	2924.7	31.7	770.5	9576.5	4418.1	16053.9	41125.0	0.0
1994	7272.1	7501.7	14773.8	6557.5	3278.6	25.8	847.6	10709.5	4064.4	17413.3	45189.3	0.0
1995	6746.5	8147.1	14893.6	7350.9	3675.3	23.0	925.4	11974.6	2919.0	18707.8	48108.3	0.0
1996	6541.8	8667.4	15209.2	8240.4	4120.0	21.5	1003.5	13385.4	1823.8	19993.6	49932.1	0.0
1997	6984.4	9091.4	16075.8	9237.5	4618.5	16.7	1082.7	14955.3	1120.5	21377.2	51052.6	0.0
1998	7159.9	9411.3	16571.2	10355.2	5177.3	14.4	1163.3	16710.2	-139.0	22839.6	50913.6	0.0

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

3

15-FEB-82

NO GASLINE
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	394.9	4213.5	1866.7	933	113.2	152.5	3065.6	1147.9	4771.9	454.5	0.0
1984	4248.0	649.6	4897.6	1919.8	959.8	127.3	148.9	3155.9	1741.7	5143.3	2158.7	0.0
1985	4565.2	974.2	5539.4	1974.4	987.1	137.9	195.1	3294.5	2244.9	5475.1	4225.4	0.0
1986	4707.8	1299.4	6007.2	2030.5	1015.2	125.0	232.1	3402.9	2604.4	5759.8	6480.8	0.0
1987	4928.5	1633.5	6562.0	2088.3	1044.1	111.8	260.1	3504.3	3057.6	6031.2	9003.4	0.0
1988	4553.6	1934.4	6488.0	2147.7	1073.8	100.6	275.3	3597.4	2890.6	6281.1	11150.6	0.0
1989	4590.5	2215.2	6805.8	2208.8	1104.3	87.4	289.2	3689.6	3116.1	6525.7	13346.0	0.0
1990	4105.0	2465.6	6570.6	2271.6	1135.7	74.1	301.6	3783.0	2787.6	6684.0	15031.6	0.0
1991	3599.5	2651.1	6250.5	2336.2	1168.0	57.6	311.9	3873.8	2376.8	6752.1	16167.3	0.0
1992	3267.1	2777.7	6044.9	2402.6	1201.2	52.5	319.9	3976.3	2068.5	6782.2	16900.9	0.0
1993	3049.5	2861.9	5911.5	2471.0	1235.4	13.4	325.5	4045.2	1866.2	6781.3	17371.6	0.0
1994	2818.2	2907.2	5725.3	2541.2	1270.5	10.0	328.5	4150.3	1575.1	6748.2	17512.3	0.0
1995	2398.6	2896.6	5295.2	2613.5	1306.7	8.2	329.0	4257.4	1037.8	6651.3	17104.2	0.0
1996	2133.8	2827.1	4960.9	2687.8	1343.8	7.0	327.3	4366.0	594.9	6521.5	16286.8	0.0
1997	2090.1	2720.6	4810.6	2764.3	1382.1	5.0	324.0	4475.3	335.3	6397.1	15277.3	0.0
1998	1965.7	2583.8	4549.4	2842.9	1421.4	4.0	319.4	4587.6	-38.2	6270.3	13977.7	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	157.0	212.8	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	225.0	222.4	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	283.1	244.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	304.2	269.5	2,869.6	0.0
1987	81.9	0.0	3,420.7	430.0	317.9	296.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	460.0	317.9	326.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	490.0	318.0	359.6	3,954.0	49.8
1990	59.5	0.0	3,386.2	520.0	318.0	395.9	3,793.3	78.1
1991	38.9	0.0	3,138.7	550.0	318.0	435.9	3,582.9	84.8
1992	38.2	0.0	3,061.4	580.0	305.0	479.9	3,389.4	255.0
1993	31.7	0.0	3,095.6	610.0	293.0	528.3	3,349.8	360.1
1994	25.8	0.0	3,092.8	640.0	281.0	581.6	3,260.1	463.2
1995	23.0	0.0	2,740.0	670.0	270.0	640.2	2,896.5	507.8
1996	21.5	0.0	2,572.1	700.0	259.0	704.9	2,670.0	606.6
1997	16.7	0.0	2,771.4	730.0	251.0	775.9	2,778.8	744.0
1998	14.4	0.0	2,799.9	730.0	238.0	854.3	2,803.6	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
OPERATING BUDGET GROWTH RATE	=	0.121
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
CAPITAL BUDGET GROWTH RATE	=	0.121
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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NO GASLINE
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	391.3	4209.9	1866.7	1384.2	113.2	152.5	3516.5	693.4	4771.9	0.0	0.0
1984	4630.3	667.6	5297.9	2092.6	2904.3	138.8	162.3	5297.9	-0.0	5606.2	0.0	0.0
1985	5424.0	981.4	6405.3	2345.8	3664.0	163.8	231.8	6405.3	0.0	6505.0	0.0	0.0
1986	6096.8	1241.8	7338.6	2629.6	4246.6	161.9	300.6	7338.6	0.0	7459.1	0.0	0.0
1987	6957.0	1476.7	8433.7	2947.8	4960.8	157.8	367.2	8433.7	0.0	8513.6	0.0	0.0
1988	7006.3	1649.5	8655.9	3304.5	4772.9	154.8	423.6	8655.9	0.0	9664.3	0.0	0.0
1989	7698.8	1806.1	9504.9	3704.3	5169.0	146.5	485.0	9504.9	0.0	10944.2	0.0	0.0
1990	7504.1	1942.5	9446.6	4152.5	4607.3	135.4	551.3	9446.6	-0.0	12218.7	0.0	0.0
1991	7172.2	2023.9	9196.1	4655.0	3804.7	114.8	621.6	9196.1	0.0	13454.1	0.0	0.0
1992	7095.9	2082.8	9178.7	5218.3	3151.5	114.1	694.8	9178.7	-0.0	14730.3	0.0	0.0
1993	7219.3	2175.2	9394.5	5849.7	2924.7	31.7	770.5	9576.5	-182.0	16053.9	0.0	182.0
1994	7272.1	2335.1	9607.2	6557.5	3278.6	25.8	847.6	10709.5	-1102.3	17413.3	0.0	1102.3
1995	6746.5	2549.2	9295.7	7350.9	3675.3	23.0	925.4	11974.6	-2678.9	18707.8	0.0	2678.9
1996	6541.8	2785.0	9326.8	8240.4	4120.0	21.5	1003.5	13385.4	-4058.6	19993.6	0.0	4058.6
1997	6984.4	3032.3	10016.7	9237.5	4618.5	16.7	1082.7	14955.3	-4938.6	21377.2	0.0	4938.6
1998	7159.9	3293.3	10453.2	10355.2	5177.3	14.4	1163.3	16710.2	-6257.0	22839.6	0.0	6257.0

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

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NO GASLINE
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3818.7	391.3	4209.9	1866.7	1384.2	113.2	152.5	3516.5	693.4	4771.9	0.0	0.0
1984	4248.0	612.5	4860.5	1919.8	2664.5	127.3	148.9	4860.5	-0.0	5143.3	0.0	0.0
1985	4565.2	826.0	5391.2	1974.4	3083.9	137.9	195.1	5391.2	0.0	5475.1	0.0	0.0
1986	4707.8	958.9	5666.8	2030.5	3279.1	125.0	232.1	5666.8	0.0	5759.8	0.0	0.0
1987	4928.5	1046.1	5974.6	2088.3	3514.4	111.8	260.1	5974.6	0.0	6031.2	0.0	0.0
1988	4553.6	1072.1	5625.7	2147.7	3102.1	100.6	275.3	5625.7	0.0	6281.1	0.0	0.0
1989	4590.5	1076.9	5667.5	2208.8	3082.1	87.4	289.2	5667.5	0.0	6525.7	0.0	0.0
1990	4105.0	1062.6	5167.6	2271.6	2520.4	74.1	301.6	5167.6	-0.0	6684.0	0.0	0.0
1991	3599.5	1015.7	4615.2	2336.2	1909.4	57.6	311.9	4615.2	0.0	6752.1	0.0	0.0
1992	3267.1	959.0	4226.1	2402.6	1451.0	52.5	319.9	4226.1	-0.0	6782.2	0.0	0.0
1993	3049.5	918.8	3968.3	2471.0	1235.4	13.4	325.5	4045.2	-76.9	6781.3	0.0	76.9
1994	2818.2	904.9	3723.1	2541.2	1270.5	10.0	328.5	4150.3	-427.2	6748.2	0.0	427.2
1995	2398.6	906.3	3304.9	2613.5	1306.7	8.2	329.0	4257.4	-952.4	6651.3	0.0	952.4
1996	2133.8	908.4	3042.2	2687.8	1343.8	7.0	327.3	4366.0	-1323.8	6521.5	0.0	1323.8
1997	2090.1	907.4	2997.5	2764.3	1382.1	5.0	324.0	4475.3	-1477.9	6397.1	0.0	1477.9
1998	1965.7	904.1	2869.8	2842.9	1421.4	4.0	319.4	4587.6	-1717.8	6270.3	0.0	1717.8

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	157.0	212.8	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	225.0	222.4	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	283.1	244.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	304.2	269.5	2,869.6	0.0
1987	81.9	0.0	3,420.7	430.0	317.9	296.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	460.0	317.9	326.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	490.0	318.0	359.6	3,954.0	49.8
1990	59.5	0.0	3,386.2	520.0	318.0	395.9	3,793.3	78.1
1991	38.9	0.0	3,138.7	550.0	318.0	435.9	3,582.9	64.8
1992	38.2	0.0	3,061.4	580.0	305.0	479.9	3,389.4	255.0
1993	31.7	0.0	3,095.6	610.0	293.0	528.3	3,349.8	360.1
1994	25.8	0.0	3,092.8	640.0	281.0	581.6	3,260.1	463.2
1995	23.0	0.0	2,740.0	670.0	270.0	640.2	2,896.5	507.8
1996	21.5	0.0	2,572.1	700.0	259.0	704.9	2,670.0	606.6
1997	16.7	0.0	2,771.4	730.0	251.0	775.9	2,778.8	744.0
1998	14.4	0.0	2,799.9	730.0	238.0	854.3	2,803.6	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
OPERATING BUDGET GROWTH RATE	=	0.121
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
CAPITAL BUDGET GROWTH RATE	=	0.121
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	400.6	4237.7	1860.6	194.6	113.2	152.5	2320.9	1916.8	4771.9	1223.4	0.0
1984	4679.0	760.3	5439.3	2141.4	240.7	138.8	162.3	2683.2	2756.2	5606.2	3979.6	0.0
1985	5593.5	1302.6	6896.0	2473.9	277.9	163.8	231.8	3147.4	3748.6	6505.0	7728.2	0.0
1986	6419.2	1968.4	8387.6	2764.1	308.0	161.9	300.6	3534.6	4853.0	7459.1	12581.2	0.0
1987	7771.5	2802.2	10573.6	3055.2	533.3	157.8	367.2	4113.5	6460.1	8513.6	19041.3	0.0
1988	7768.7	3751.6	11520.3	3308.1	390.6	154.8	423.6	4277.2	7243.2	9664.3	26284.4	0.0
1989	8420.5	4825.5	13246.0	3684.0	436.3	146.5	485.0	4751.8	8494.2	10944.2	34778.6	0.0
1990	8256.7	6020.5	14277.2	4102.5	487.4	135.4	551.4	5276.7	9000.6	12230.6	43779.2	0.0
1991	8093.4	7292.8	15386.1	4568.5	544.4	114.8	622.1	5849.8	9536.4	13514.2	53315.6	0.0
1992	8192.2	8655.3	16847.4	5087.5	608.1	114.1	696.6	6506.3	10341.1	14879.6	63656.7	0.0
1993	8451.6	10141.8	18593.4	5665.4	679.2	31.7	774.8	7151.1	11442.3	16329.9	75099.0	0.0
1994	8518.3	11756.4	20274.6	6309.0	758.7	25.8	856.1	7949.6	12325.0	17832.4	87424.1	0.0
1995	8008.8	13449.4	21458.2	7025.7	847.5	23.0	939.8	8836.0	12622.2	19285.7	100046.3	0.0
1996	7813.0	15202.1	23015.1	7823.8	946.6	21.5	1025.5	9817.4	13197.7	20745.7	113244.0	0.0
1997	8279.3	17073.1	25352.4	8712.6	1057.4	16.7	1113.6	10900.3	14452.1	22326.0	127696.1	0.0
1998	8463.5	19088.5	27552.0	9702.4	1181.1	14.4	1204.2	12102.1	15449.9	23993.5	143146.0	0.0

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	400.6	4237.7	1860.6	194.6	113.2	152.5	2320.9	1916.8	4771.9	1223.4	0.0
1984	4292.7	697.5	4990.2	1964.6	220.8	127.3	148.9	2461.6	2528.6	5143.3	3651.0	0.0
1985	4707.9	1096.4	5804.3	2082.3	233.9	137.9	195.1	2649.1	3155.1	5475.1	6504.7	0.0
1986	4956.8	1519.9	6476.7	2134.4	237.8	125.0	232.1	2729.4	3747.4	5759.8	9715.0	0.0
1987	5505.5	1985.1	7490.6	2164.4	377.8	111.8	260.1	2914.1	4576.5	6031.2	13489.3	0.0
1988	5049.1	2438.3	7487.4	2150.1	253.9	100.6	275.3	2779.9	470[illegible].6	6281.1	17083.1	0.0
1989	5020.9	2877.3	7898.1	2196.6	260.2	87.4	289.2	2833.3	5064.8	6525.7	20737.4	0.0
1990	4516.7	3293.4	7810.1	2244.2	266.6	74.1	301.6	2886.5	4923.6	6690.6	23948.7	0.0
1991	4061.8	3660.0	7721.8	2292.8	273.2	57.6	312.2	2935.8	4786.0	6782.3	26757.3	0.0
1992	3771.9	3985.1	7757.0	2342.4	280.0	52.5	320.7	2995.7	4761.3	6851.0	29309.3	0.0
1993	3570.0	4284.0	7854.1	2393.1	286.9	13.4	327.3	3020.7	4833.4	6897.9	31722.6	0.0
1994	3301.1	4556.0	7857.1	2444.9	294.0	10.0	331.8	3080.7	4776.4	6910.6	33879.7	0.0
1995	2847.4	4781.7	7629.1	2497.9	301.3	8.2	334.1	3141.5	4487.6	6856.7	35569.9	0.0
1996	2548.4	4958.6	7507.0	2552.0	308.8	7.0	334.5	3202.2	4304.8	6766.8	36937.8	0.0
1997	2477.5	5109.1	7586.6	2607.2	316.4	5.0	333.2	3261.9	4324.7	6681.0	38212.6	0.0
1998	2323.6	5240.5	7564.1	2663.7	324.3	4.0	330.6	3322.5	4241.6	6587.1	39299.0	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	256.0	240.1	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	399.0	298.4	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	543.2	352.9	2,869.6	0.0
1987	81.9	0.0	3,420.7	641.5	857.9	359.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	663.0	836.3	367.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	684.6	814.8	389.9	3,954.0	49.8
1990	59.5	0.0	3,421.2	706.1	793.2	418.2	3,838.6	78.1
1991	38.9	0.0	3,256.9	747.3	771.6	453.3	3,762.5	84.8
1992	38.2	0.0	3,257.3	792.3	737.0	495.4	3,710.2	255.0
1993	31.7	0.0	3,348.7	833.7	703.4	544.0	3,789.0	360.1
1994	25.8	0.0	3,357.0	861.2	669.8	598.6	3,733.4	463.2
1995	23.0	0.0	3,014.3	889.3	637.2	658.5	3,407.5	507.8
1996	21.5	0.0	2,844.4	918.6	604.6	724.8	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.2	575.0	797.6	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.1	540.4	878.0	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	390.9	4228.0	1860.6	1408.3	113.2	152.5	3534.6	693.4	4771.9	0.0	0.0
1984	4679.0	670.0	5349.0	2141.4	2906.6	138.8	162.3	5349.0	0.0	5606.2	0.0	0.0
1985	5593.5	987.7	6581.1	2473.9	3711.6	163.8	231.8	6581.1	0.0	6505.0	0.0	0.0
1986	6419.2	1259.1	7678.3	2764.1	4451.7	161.9	300.6	7678.3	0.0	7459.1	0.0	0.0
1987	7771.5	1534.4	9305.8	3055.2	5725.6	157.8	367.2	9305.8	0.0	8513.6	0.0	0.0
1988	7768.7	1751.0	9519.8	3308.1	5633.2	154.8	423.6	9519.8	0.0	9664.3	0.0	0.0
1989	8420.5	1926.1	10346.6	3684.0	6031.1	146.5	485.0	10346.6	0.0	10944.2	0.0	0.0
1990	8256.7	2067.7	10324.4	4102.5	5535.1	135.4	551.4	10324.4	0.0	12230.6	0.0	0.0
1991	8093.4	2165.1	10258.5	4568.5	4953.1	114.8	622.1	10258.5	0.0	13514.2	0.0	0.0
1992	8192.2	2255.0	10447.1	5087.5	4549.0	114.1	696.6	10447.1	0.0	14879.6	0.0	0.0
1993	8451.6	2374.7	10826.3	5665.4	4354.4	31.7	774.8	10826.3	0.0	16329.9	0.0	0.0
1994	8518.3	2503.0	11021.3	6309.0	3830.3	25.8	856.1	11021.3	0.0	17832.4	0.0	0.0
1995	8008.8	2583.4	10592.2	7025.7	2603.7	23.0	939.8	10592.2	0.0	19285.7	0.0	0.0
1996	7813.0	2625.0	10437.9	7823.8	1567.1	21.5	1025.5	10437.9	0.0	20745.7	0.0	0.0
1997	8279.3	2702.4	10981.6	8712.6	1138.8	16.7	1113.6	10981.6	-0.0	22326.0	0.0	0.0
1998	8463.5	2857.4	11320.9	9702.4	1181.1	14.4	1204.2	12102.1	-781.1	23993.5	0.0	781.1

STATE OF ALASKA
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BUDGET FORECASTING MODEL
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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	390.9	4228.0	1860.6	1408.3	113.2	152.5	3534.6	693.4	4771.9	0.0	0.0
1984	4292.7	614.7	4907.4	1964.6	2666.6	127.3	148.9	4907.4	0.0	5143.3	0.0	0.0
1985	4707.9	831.3	5539.2	2082.3	3124.0	137.9	195.1	5539.2	0.0	5475.1	0.0	0.0
1986	4956.8	972.3	5929.1	2134.4	3437.5	125.0	232.1	5929.1	0.0	5759.8	0.0	0.0
1987	5505.5	1087.0	6592.5	2164.4	4056.2	111.8	260.1	6592.5	0.0	6031.2	0.0	0.0
1988	5049.1	1138.0	6187.2	2150.1	3661.2	100.6	275.3	6187.2	0.0	6281.1	0.0	0.0
1989	5020.9	1148.5	6169.4	2196.6	3596.2	87.4	289.2	6169.4	0.0	6525.7	0.0	0.0
1990	4516.7	1131.1	5647.8	2244.2	3027.9	74.1	301.6	5647.8	0.0	6690.6	0.0	0.0
1991	4061.8	1086.6	5148.4	2292.8	2485.8	57.6	312.2	5148.4	0.0	6782.3	0.0	0.0
1992	3771.9	1038.3	4810.2	2342.4	2094.5	52.5	320.7	4810.2	0.0	6851.0	0.0	0.0
1993	3570.0	1003.1	4573.1	2393.1	1839.3	13.4	327.3	4573.1	0.0	6897.9	0.0	0.0
1994	3301.1	970.0	4271.1	2444.9	1484.4	10.0	331.8	4271.1	0.0	6910.6	0.0	0.0
1995	2847.4	918.5	3765.9	2497.9	925.7	8.2	334.1	3765.9	0.0	6856.7	0.0	0.0
1996	2548.4	856.2	3404.6	2552.0	511.2	7.0	334.5	3404.6	0.0	6766.8	0.0	0.0
1997	2477.5	808.7	3286.2	2607.2	340.8	5.0	333.2	3286.2	-0.0	6681.0	0.0	0.0
1998	2323.6	784.5	3108.0	2663.7	324.3	4.0	330.6	3322.5	-214.5	6587.1	0.0	214.5

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	256.0	240.1	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	399.0	298.4	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	543.2	352.9	2,869.6	0.0
1987	81.9	0.0	3,420.7	641.5	857.9	359.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	663.0	836.3	367.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	684.6	814.8	389.9	3,954.0	49.8
1990	59.5	0.0	3,421.2	706.1	793.2	418.2	3,838.6	78.1
1991	38.9	0.0	3,256.9	747.3	771.6	453.3	3,762.5	84.8
1992	38.2	0.0	3,257.3	792.3	737.0	495.4	3,710.2	255.0
1993	31.7	0.0	3,348.7	833.7	703.4	544.0	3,789.0	360.1
1994	25.8	0.0	3,357.0	861.2	669.8	598.6	3,733.4	463.2
1995	23.0	0.0	3,014.3	889.3	637.2	658.5	3,407.5	507.8
1996	21.5	0.0	2,844.4	918.6	604.6	724.8	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.2	575.0	797.6	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.1	540.4	878.0	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	439.0	4276.2	1904.4	952.1	113.2	152.5	3122.2	1154.0	4771.9	460.6	0.0
1984	4679.0	722.4	5401.4	2229.4	1114.7	138.8	162.3	3645.2	1756.2	5606.2	2216.8	0.0
1985	5593.5	1144.4	6737.9	2624.5	1312.2	163.8	231.8	4332.3	2405.6	6505.0	4622.4	0.0
1986	6419.2	1651.0	8070.2	2940.8	1470.3	161.9	300.6	4873.5	3196.7	7459.1	7819.1	0.0
1987	7771.5	2286.6	10058.1	3241.9	1620.8	157.8	367.2	5387.8	4670.3	8513.6	12489.3	0.0
1988	7768.7	3003.6	10772.3	3484.4	1742.1	154.8	423.6	5804.9	4967.4	9664.3	17456.7	0.0
1989	8420.5	3801.0	12221.5	3906.0	1952.9	146.5	485.0	6490.4	5731.1	10944.2	23187.8	0.0
1990	8256.7	4658.0	12914.7	4378.6	2189.2	135.4	551.4	7254.6	5660.0	12230.6	28847.9	0.0
1991	8093.4	5516.9	13610.3	4908.4	2454.1	114.8	622.1	8099.4	5510.9	13514.2	34358.8	0.0
1992	8192.2	6380.1	14572.3	5502.4	2751.0	114.1	696.6	9064.1	5508.2	14879.6	39867.0	0.0
1993	8451.6	7266.0	15717.6	6168.1	3083.9	31.7	774.8	10058.5	5659.1	16329.9	45526.0	0.0
1994	8518.3	8160.4	16678.6	6914.5	3457.0	25.8	856.1	11253.4	5425.2	17832.4	50951.2	0.0
1995	8008.8	8992.6	17001.5	7751.1	3875.3	23.0	939.8	12589.2	4412.2	19285.7	55363.4	0.0
1996	7813.0	9719.7	17532.7	8689.0	4344.3	21.5	1025.5	14080.3	3452.4	20745.7	58815.8	0.0
1997	8279.3	10371.5	18650.8	9740.4	4869.9	16.7	1113.6	15740.6	2910.2	22326.0	61726.1	0.0
1998	8463.5	10941.2	19404.7	10919.0	5459.2	14.4	1204.2	17596.8	1807.9	23993.5	63533.9	0.0

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	439.0	4276.2	1904.4	952.1	113.2	152.5	3122.2	1154.0	4771.9	460.6	0.0
1984	4292.7	662.7	4955.4	2045.4	1022.6	127.3	148.9	3344.2	1611.2	5143.3	2033.7	0.0
1985	4707.9	963.2	5671.1	2209.0	1104.4	137.9	195.1	3646.4	2024.8	5475.1	3890.5	0.0
1986	4956.8	1274.9	6231.7	2270.8	1135.3	125.0	232.1	3763.3	2468.4	5759.8	6037.7	0.0
1987	5505.5	1619.9	7125.4	2296.6	1148.3	111.8	260.1	3816.8	3308.5	6031.2	8847.8	0.0
1988	5049.1	1952.1	7001.3	2264.6	1132.2	100.6	275.3	3772.8	3228.5	6281.1	11345.7	0.0
1989	5020.9	2266.4	7287.3	2329.0	1164.4	87.4	289.2	3870.0	3417.3	6525.7	13826.2	0.0
1990	4516.7	2548.1	7064.8	2395.3	1197.6	74.1	301.6	3968.5	3096.2	6690.6	15780.8	0.0
1991	4061.8	2768.7	6830.5	2463.4	1231.6	57.6	312.2	4064.8	2765.7	6782.3	17243.5	0.0
1992	3771.9	2937.6	6709.5	2533.4	1266.6	52.5	320.7	4173.4	2536.1	[illegible]351.0	18355.9	0.0
1993	3570.0	3069.2	6639.3	2605.5	1302.7	13.4	327.3	4248.8	2390.5	6897.9	19230.7	0.0
1994	3301.1	3162.4	6463.5	2679.6	1339.7	10.0	331.8	4361.1	2102.4	6910.6	19745.3	0.0
1995	2847.4	3197.2	6044.6	2755.8	1377.8	8.2	334.1	4475.9	1568.7	6856.7	19683.6	0.0
1996	2548.4	3170.4	5718.8	2834.2	1417.0	7.0	334.5	4592.7	1126.1	6766.8	19184.5	0.0
1997	2477.5	3103.6	5581.2	2914.8	1457.3	5.0	333.2	4710.3	870.9	6681.0	18471.3	0.0
1998	2323.6	3003.8	5327.3	2997.7	1498.7	4.0	330.6	4831.0	496.3	6587.1	17442.5	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	256.0	240.1	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	399.0	298.4	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	543.2	352.9	2,869.6	0.0
1987	81.9	0.0	3,420.7	641.5	857.9	359.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	663.0	836.3	367.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	684.6	814.8	389.9	3,954.0	49.8
1990	59.5	0.0	3,421.2	706.1	793.2	418.2	3,838.6	78.1
1991	38.9	0.0	3,256.9	747.3	771.6	453.3	3,762.5	84.8
1992	38.2	0.0	3,257.3	792.3	737.0	495.4	3,710.2	255.0
1993	31.7	0.0	3,348.7	833.7	703.4	544.0	3,789.0	360.1
1994	25.8	0.0	3,357.0	861.2	669.8	598.6	3,733.4	463.2
1995	23.0	0.0	3,014.3	889.3	637.2	658.5	3,407.5	507.8
1996	21.5	0.0	2,844.4	918.6	604.6	724.8	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.2	575.0	797.6	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.1	540.4	878.0	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	435.4	4272.5	1904.4	1409.0	113.2	152.5	3579.1	693.4	4771.9	0.0	0.0
1984	4679.0	682.7	5361.7	2229.4	2831.2	138.8	162.3	5361.7	0.0	5606.2	0.0	0.0
1985	5593.5	977.8	6571.2	2624.5	3551.1	163.8	231.8	6571.2	0.0	6505.0	0.0	0.0
1986	6419.2	1240.6	7659.8	2940.8	4256.5	161.9	300.6	7659.8	0.0	7459.1	0.0	0.0
1987	7771.5	1511.0	9282.5	3241.9	5515.5	157.8	367.2	9282.5	0.0	8513.6	0.0	0.0
1988	7768.7	1726.1	9494.9	3484.4	5432.0	154.8	423.6	9494.9	0.0	9664.3	0.0	0.0
1989	8420.5	1900.1	10320.6	3906.0	5783.1	146.5	485.0	10320.6	-0.0	10944.2	0.0	0.0
1990	8256.7	2036.9	10293.6	4378.6	5228.2	135.4	551.4	10293.6	0.0	12230.6	0.0	0.0
1991	8093.4	2127.2	10220.5	4908.4	4575.2	114.8	622.1	10220.5	0.0	13514.2	0.0	0.0
1992	8192.2	2208.3	10400.5	5502.4	4087.4	114.1	696.6	10400.5	-0.0	14879.6	0.0	0.0
1993	8451.6	2317.7	10769.3	6168.1	3794.6	31.7	774.8	10769.3	0.0	16329.9	0.0	0.0
1994	8518.3	2449.8	10968.0	6914.5	3457.0	25.8	856.1	11253.4	-285.4	17832.4	0.0	285.4
1995	8008.8	2629.8	10638.6	7751.1	3875.3	23.0	939.8	12589.2	-1950.7	19285.7	0.0	1950.7
1996	7813.0	2869.0	10681.9	8689.0	4344.3	21.5	1025.5	14080.3	-3398.4	20745.7	0.0	3398.4
1997	8279.3	3139.0	11418.3	9740.4	4869.9	16.7	1113.6	15740.6	-4322.3	22326.0	-0.0	4322.3
1998	8463.5	3425.6	11889.1	10919.0	5459.2	14.4	1204.2	17596.8	-5707.7	23993.5	0.0	5707.7

STATE OF ALASKA

LEGISLATIVE FINANCE WORKING DOCUMENT

BUDGET FORECASTING MODEL

FY 1983 $

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GASLINE DEC 1986-LOW INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	435.4	4272.5	1904.4	1409.0	113.2	152.5	3579.1	693.4	4771.9	0.0	0.0
1984	4292.7	626.3	4919.0	2045.4	2597.4	127.3	148.9	4919.0	0.0	5143.3	0.0	0.0
1985	4707.9	823.0	5530.9	2209.0	2988.9	137.9	195.1	5530.9	0.0	5475.1	0.0	0.0
1986	4956.8	958.0	5914.8	2270.8	3286.8	125.0	232.1	5914.8	0.0	5759.8	0.0	0.0
1987	5505.5	1070.5	6575.9	2296.6	3907.4	111.8	260.1	6575.9	0.0	6031.2	0.0	0.0
1988	5049.1	1121.9	6171.0	2264.6	3530.4	100.6	275.3	6171.0	0.0	6281.1	0.0	0.0
1989	5020.9	1133.0	6153.9	2329.0	3448.3	87.4	289.2	6153.9	-0.0	6525.7	0.0	0.0
1990	4516.7	1114.3	5631.0	2395.3	2860.0	74.1	301.6	5631.0	0.0	6690.6	0.0	0.0
1991	4061.8	1067.6	5129.3	2463.4	2296.1	57.6	312.2	5129.3	0.0	6782.3	0.0	0.0
1992	3771.9	1016.8	4788.7	2533.4	1881.9	52.5	320.7	4788.7	-0.0	6851.0	0.0	0.0
1993	3570.0	979.0	4549.1	2605.5	1602.9	13.4	327.3	4549.1	0.0	6897.9	0.0	0.0
1994	3301.1	949.4	4250.5	2679.6	1339.7	10.0	331.8	4361.1	-110.6	6910.6	0.0	110.6
1995	2847.4	935.0	3782.4	2755.8	1377.8	8.2	334.1	4475.9	-693.5	6856.7	0.0	693.5
1996	2548.4	935.8	3484.2	2834.2	1417.0	7.0	334.5	4592.7	-1108.5	6766.8	0.0	1108.5
1997	2477.5	939.3	3416.9	2914.8	1457.3	5.0	333.2	4710.3	-1293.4	6681.0	-0.0	1293.4
1998	2323.6	940.4	3264.0	2997.7	1498.7	4.0	330.6	4831.0	-1567.0	6587.1	0.0	1567.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	256.0	240.1	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	399.0	298.4	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	543.2	352.9	2,869.6	0.0
1987	81.9	0.0	3,420.7	641.5	857.9	359.7	3,322.2	0.0
1988	78.9	0.0	3,179.9	663.0	836.3	367.7	3,629.1	0.0
1989	70.6	0.0	3,540.8	684.6	814.8	389.9	3,954.0	49.8
1990	59.5	0.0	3,421.2	706.1	793.2	418.2	3,838.6	78.1
1991	38.9	0.0	3,256.9	747.3	771.6	453.3	3,762.5	84.8
1992	38.2	0.0	3,257.3	792.3	737.0	495.4	3,710.2	255.0
1993	31.7	0.0	3,348.7	833.7	703.4	544.0	3,789.0	360.1
1994	25.8	0.0	3,357.0	861.2	669.8	598.6	3,733.4	463.2
1995	23.0	0.0	3,014.3	889.3	637.2	658.5	3,407.5	507.8
1996	21.5	0.0	2,844.4	918.6	604.6	724.8	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.2	575.0	797.6	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.1	540.4	878.0	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM- ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	446.0	4283.2	1877.9	196.5	113.2	152.5	2340.1	1943.1	4771.9	1249.7	0.0
1984	4680.1	776.0	5456.2	2224.0	249.9	138.8	162.3	2774.9	2681.2	5606.2	3931.0	0.0
1985	5604.9	1289.2	6894.0	2694.8	302.5	163.8	231.8	3392.9	3501.2	6505.0	7432.1	0.0
1986	6455.3	1920.6	8375.9	3127.3	348.2	161.9	300.6	3938.0	4438.0	7459.1	11870.1	0.0
1987	7834.1	2704.5	10538.5	3417.5	595.1	157.8	367.2	4537.6	6000.9	8513.6	17871.0	0.0
1988	7826.8	3595.9	11422.8	3700.5	436.9	154.8	423.6	4715.8	6707.0	9664.3	24578.0	0.0
1989	8474.9	4598.8	13073.7	4120.8	488.1	146.5	485.0	5240.5	7833.2	10944.2	32411.2	0.0
1990	8245.7	5703.2	13948.9	4588.9	545.2	135.4	551.3	5820.9	8128.0	12221.1	40539.2	0.0
1991	7976.9	6855.1	14832.0	5110.3	608.9	114.8	621.7	6455.7	8376.3	13474.8	48915.5	0.0
1992	8051.9	8064.8	16116.7	5690.8	680.2	114.1	695.6	7180.7	8936.1	14804.0	57851.5	0.0
1993	8353.1	9370.4	17723.5	6337.3	759.8	31.7	772.7	7901.4	9822.1	16223.2	67673.7	0.0
1994	8559.9	10782.1	19342.0	7057.2	848.7	25.8	852.7	8784.3	10557.7	17719.4	78231.3	0.0
1995	8048.4	12244.2	20292.6	7858.9	948.0	23.0	935.0	9764.9	10527.8	19168.4	88759.1	0.0
1996	7850.7	13724.4	21575.0	8751.6	1058.9	21.5	1019.6	10851.6	10723.4	20626.0	99482.5	0.0
1997	8315.0	15274.8	23589.7	9745.8	1182.8	16.7	1106.9	12052.2	11537.5	22205.2	111020.0	0.0
1998	8497.4	16913.8	25411.2	10852.9	1321.1	14.4	1197.2	13385.6	12025.6	23872.2	123045.6	0.0

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
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GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	446.0	4283.2	1877.9	196.5	113.2	152.5	2340.1	1943.1	4771.9	1249.7	0.0
1984	4293.7	712.0	5005.7	2040.3	229.3	127.3	148.9	2545.8	2459.8	5143.3	3606.4	0.0
1985	4717.5	1085.1	5802.6	2268.1	254.6	137.9	195.1	2855.7	2946.9	5475.1	6255.5	0.0
1986	4984.7	1483.1	6467.8	2414.8	268.9	125.0	232.1	3040.8	3426.9	5759.8	9165.9	0.0
1987	5549.8	1915.9	7465.8	2421.0	421.6	111.8	260.1	3214.6	4251.2	6031.2	12660.3	0.0
1988	5086.9	2337.1	7424.0	2405.0	284.0	100.6	275.3	3064.9	4359.1	6281.1	15974.0	0.0
1989	5053.3	2742.1	7795.4	2457.1	291.0	87.4	289.2	3124.7	4670.7	6525.7	19325.7	0.0
1990	4510.7	3119.9	7630.5	2510.3	298.2	74.1	301.6	3184.2	4446.3	6685.3	22176.3	0.0
1991	4003.3	3440.4	7443.7	2564.7	305.6	57.6	312.0	3239.9	4203.8	6762.5	24549.0	0.0
1992	3707.3	3713.3	7420.6	2620.2	313.2	52.5	320.3	3306.2	4114.4	6816.2	26636.5	0.0
1993	3528.5	3958.2	7486.6	2676.9	320.9	13.4	326.4	3337.6	4149.0	6852.8	28586.1	0.0
1994	3317.2	4178.4	7495.7	2734.9	328.9	10.0	330.4	3404.2	4091.4	6866.8	30317.2	0.0
1995	2861.5	4353.2	7214.7	2794.1	337.0	8.2	332.4	3471.7	3743.0	6815.0	31556.9	0.0
1996	2560.7	4476.6	7037.3	2854.6	345.4	7.0	332.6	3539.6	3497.8	6727.8	32449.1	0.0
1997	2488.2	4570.9	7059.1	2916.4	353.9	5.0	331.2	3606.6	3452.6	6644.8	33222.4	0.0
1998	2332.9	4643.5	6976.3	2979.5	362.7	4.0	328.7	3674.9	3301.5	6553.8	33780.7	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	257.0	240.2	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	409.0	299.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	572.8	359.4	2,869.6	0.0
1987	81.9	0.0	3,420.7	642.7	911.9	367.1	3,322.2	0.0
1988	78.9	0.0	3,179.9	664.2	888.1	372.8	3,629.1	0.0
1989	70.6	0.0	3,540.8	685.7	864.5	393.5	3,954.0	49.8
1990	59.5	0.0	3,386.2	707.2	840.7	420.8	3,802.3	78.1
1991	38.9	0.0	3,193.1	730.0	817.0	455.3	3,652.1	84.8
1992	38.2	0.0	3,186.3	772.4	780.2	497.3	3,584.3	255.0
1993	31.7	0.0	3,295.9	818.4	744.4	545.9	3,691.3	360.1
1994	25.8	0.0	3,357.0	862.0	708.7	600.5	3,733.4	463.2
1995	23.0	0.0	3,014.3	890.1	673.9	660.6	3,407.5	507.8
1996	21.5	0.0	2,844.4	919.3	639.2	727.2	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.9	607.4	800.2	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.9	570.6	880.9	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	436.2	4273.3	1877.9	1436.3	113.2	152.5	3579.9	693.4	4771.9	0.0	0.0
1984	4680.1	684.9	5365.0	2224.0	2839.9	138.8	162.3	5365.0	-0.0	5606.2	0.0	0.0
1985	5604.9	977.6	6582.4	2694.8	3492.1	163.8	231.8	6582.4	-0.0	6505.0	0.0	0.0
1986	6455.3	1233.0	7688.3	3127.3	4098.5	161.9	300.6	7688.3	0.0	7459.1	0.0	0.0
1987	7834.1	1496.6	9330.6	3417.5	5388.1	157.8	367.2	9330.6	0.0	8513.6	0.0	0.0
1988	7826.8	1710.0	9536.8	3700.5	5257.9	154.8	423.6	9536.8	-0.0	9664.3	0.0	0.0
1989	8474.9	1881.3	10356.2	4120.8	5603.8	146.5	485.0	10356.2	-0.0	10944.2	0.0	0.0
1990	8245.7	2013.0	10258.6	4588.9	4982.9	135.4	551.3	10258.6	0.0	12221.1	0.0	0.0
1991	7976.9	2092.2	10069.1	5110.3	4222.3	114.8	621.7	10069.1	0.0	13474.8	0.0	0.0
1992	8051.9	2161.8	10213.7	5690.8	3713.2	114.1	695.6	10213.7	0.0	14804.0	0.0	0.0
1993	8353.1	2267.7	10620.8	6337.3	3479.2	31.7	772.7	10620.8	0.0	16223.2	0.0	0.0
1994	8559.9	2393.5	10953.4	7057.2	3017.7	25.8	852.7	10953.4	-0.0	17719.4	0.0	0.0
1995	8048.4	2472.0	10520.4	7858.9	1703.6	23.0	935.0	10520.4	0.0	19168.4	0.0	0.0
1996	7850.7	2529.7	10380.3	8751.6	1058.9	21.5	1019.6	10851.6	-471.3	20626.0	0.0	471.3
1997	8315.0	2661.6	10976.6	9745.8	1182.8	16.7	1106.9	12052.2	-1075.6	22205.2	0.0	1075.6
1998	8497.4	2869.9	11367.3	10852.9	1321.1	14.4	1197.2	13385.6	-2018.3	23872.2	0.0	2018.3

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GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
FY82 LEVEL OF SERVICE BUDGETS
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	436.2	4273.3	1877.9	1436.3	113.2	152.5	3579.9	693.4	4771.9	0.0	0.0
1984	4293.7	628.3	4922.0	2040.3	2605.4	127.3	148.9	4922.0	-0.0	5143.3	0.0	0.0
1985	4717.5	822.8	5540.3	2268.1	2939.2	137.9	195.1	5540.3	-0.0	5475.1	0.0	0.0
1986	4984.7	952.1	5936.8	2414.8	3164.8	125.0	232.1	5936.8	0.0	5759.8	0.0	0.0
1987	5549.8	1060.2	6610.0	2421.0	3817.1	111.8	260.1	6610.0	0.0	6031.2	0.0	0.0
1988	5086.9	1111.4	6198.3	2405.0	3417.3	100.6	275.3	6198.3	-0.0	6281.1	0.0	0.0
1989	5053.3	1121.7	6175.0	2457.1	3341.4	87.4	289.2	6175.0	-0.0	6525.7	0.0	0.0
1990	4510.7	1101.2	5611.8	2510.3	2725.8	74.1	301.6	5611.8	0.0	6685.3	0.0	0.0
1991	4003.3	1050.0	5053.3	2564.7	2119.0	57.6	312.0	5053.3	0.0	6762.5	0.0	0.0
1992	3707.3	995.3	4702.7	2620.2	1709.7	52.5	320.3	4702.7	0.0	6816.2	0.0	0.0
1993	3528.5	957.9	4486.4	2676.9	1469.7	13.4	326.4	4486.4	0.0	6852.8	0.0	0.0
1994	3317.2	927.6	4244.8	2734.9	1169.5	10.0	330.4	4244.8	-0.0	6866.8	0.0	0.0
1995	2861.5	878.9	3740.4	2794.1	605.7	8.2	332.4	3740.4	0.0	6815.0	0.0	0.0
1996	2560.7	825.1	3385.8	2854.6	345.4	7.0	332.6	3539.6	-153.7	6727.8	0.0	153.7
1997	2488.2	796.5	3284.7	2916.4	353.9	5.0	331.2	3606.6	-321.9	6644.8	0.0	321.9
1998	2332.9	787.9	3120.8	2979.5	362.7	4.0	328.7	3674.9	-554.1	6553.8	0.0	554.1

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	257.0	240.2	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	409.0	299.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	572.8	359.4	2,869.6	0.0
1987	81.9	0.0	3,420.7	642.7	911.9	367.1	3,322.2	0.0
1988	78.9	0.0	3,179.9	664.2	888.1	372.8	3,629.1	0.0
1989	70.6	0.0	3,540.8	685.7	864.5	393.5	3,954.0	49.8
1990	59.5	0.0	3,386.2	707.2	840.7	420.8	3,802.3	78.1
1991	38.9	0.0	3,193.1	730.0	817.0	455.3	3,652.1	84.8
1992	38.2	0.0	3,186.3	772.4	780.2	497.3	3,584.3	255.0
1993	31.7	0.0	3,295.9	818.4	744.4	545.9	3,691.3	360.1
1994	25.8	0.0	3,357.0	862.0	708.7	600.5	3,733.4	463.2
1995	23.0	0.0	3,014.3	890.1	673.9	660.6	3,407.5	507.8
1996	21.5	0.0	2,844.4	919.3	639.2	727.2	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.9	607.4	800.2	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.9	570.6	880.9	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	438.2	4275.4	1922.2	961.0	113.2	152.5	3148.9	1126.5	4771.9	433.1	0.0
1984	4680.1	715.9	5396.0	2315.7	1157.8	138.8	162.3	3774.5	1621.5	5606.2	2054.6	0.0
1985	5604.9	1117.8	6722.7	2859.2	1429.5	163.8	231.8	4684.3	2038.4	6505.0	4093.0	0.0
1986	6455.3	1584.0	8039.3	3205.4	1602.6	161.9	300.6	5270.5	2768.8	7459.1	6861.8	0.0
1987	7834.1	2170.1	10004.1	3493.9	1746.8	157.8	367.2	5765.8	4238.3	8513.6	11100.1	0.0
1988	7826.8	2830.7	10657.5	3755.2	1877.5	154.8	423.6	6211.2	4446.3	9664.3	15546.4	0.0
1989	8474.9	3560.5	12035.4	4209.6	2104.7	146.5	485.0	6945.8	5089.6	10944.2	20636.0	0.0
1990	8245.7	4331.1	12576.8	4719.0	2359.4	135.4	551.3	7765.1	4811.7	12221.1	25447.7	0.0
1991	7976.9	5074.4	13051.3	5290.0	2644.8	114.8	621.7	8671.4	4379.9	13474.8	29827.6	0.0
1992	8051.9	5790.3	13842.2	5930.1	2964.9	114.1	695.6	9704.6	4137.6	14804.0	33965.1	0.0
1993	8353.1	6501.5	14854.7	6647.6	3323.6	31.7	772.7	10775.6	4079.1	16223.2	38044.2	0.0
1994	8559.9	7200.4	15760.2	7452.0	3725.8	25.8	852.7	12056.2	3704.0	17719.4	41748.2	0.0
1995	8048.4	7810.0	15858.4	8353.7	4176.6	23.0	935.0	13488.3	2370.2	19168.4	44118.4	0.0
1996	7850.7	8273.9	16124.5	9364.5	4682.0	21.5	1019.6	15087.5	1037.0	20626.0	45155.4	0.0
1997	8315.0	8615.6	16930.6	10497.6	5248.5	16.7	1106.9	16869.7	60.9	22205.2	45216.3	0.0
1998	8497.4	8820.6	17318.0	11767.8	5883.5	14.4	1197.2	18862.9	-1544.9	23872.2	43671.4	0.0

STATE OF ALASKA
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BUDGET FORECASTING MODEL
FY 1983 $

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15-FEB-82

GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	438.2	4275.4	1922.2	961.0	113.2	152.5	3148.9	1126.5	4771.9	433.1	0.0
1984	4293.7	656.8	4950.5	2124.5	1062.2	127.3	148.9	3462.9	1487.6	5143.3	1884.9	0.0
1985	4717.5	940.9	5658.3	2406.5	1203.2	137.9	195.1	3942.6	1715.7	5475.1	3445.0	0.0
1986	4984.7	1223.2	6207.8	2475.2	1237.5	125.0	232.1	4069.8	2138.0	5759.8	5298.6	0.0
1987	5549.8	1537.3	7087.2	2475.2	1237.5	111.8	260.1	4084.6	3002.5	6031.2	7863.6	0.0
1988	5086.9	1839.8	6926.7	2440.7	1220.3	100.6	275.3	4036.9	2889.8	6281.1	10104.1	0.0
1989	5053.3	2123.0	7176.3	2510.1	1255.0	87.4	289.2	4141.6	3034.7	6525.7	12304.6	0.0
1990	4510.7	2369.3	6879.9	2581.5	1290.6	74.1	301.6	4247.8	2632.2	6685.3	13920.8	0.0
1991	4003.3	2546.7	6550.0	2654.9	1327.4	57.6	312.0	4351.9	2198.1	6762.5	14969.5	0.0
1992	3707.3	2666.0	6373.3	2730.4	1365.1	52.5	320.3	4468.3	1905.0	6816.2	15638.5	0.0
1993	3528.5	2746.3	6274.8	2808.0	1403.9	13.4	326.4	4551.7	1723.0	6852.8	16070.3	0.0
1994	3317.2	2790.4	6107.6	2887.9	1443.9	10.0	330.4	4672.2	1435.4	6866.8	16178.8	0.0
1995	2861.5	2776.7	5638.2	2970.0	1484.9	8.2	332.4	4795.5	842.7	6815.0	15685.6	0.0
1996	2560.7	2698.8	5259.5	3054.5	1527.2	7.0	332.6	4921.2	338.3	6727.8	14728.7	0.0
1997	2488.2	2578.2	5066.4	3141.4	1570.6	5.0	331.2	5048.2	18.2	6644.8	13530.8	0.0
1998	2332.9	2421.6	4754.4	3230.7	1615.3	4.0	328.7	5178.6	-424.1	6553.8	11989.5	0.0

ASSUMPTIONS

	EXISTING DEBT SERVICE	NEW DEBT	SEVERANCE TAXES	PETROL INCOME TAX	PROPERTY TAX	OTHER REVENUE	ROYALTIES X% TO PF	ROYALTIES 50% TO PF
1983	94.2	0.0	1,819.6	304.0	169.0	219.3	1,767.0	0.0
1984	91.3	0.0	2,214.1	360.0	257.0	240.2	2,145.1	0.0
1985	87.9	0.0	2,616.1	373.0	409.0	299.8	2,542.6	0.0
1986	86.0	0.0	2,970.9	400.0	572.8	359.4	2,869.6	0.0
1987	81.9	0.0	3,420.7	642.7	911.9	367.1	3,322.2	0.0
1988	78.9	0.0	3,179.9	664.2	888.1	372.8	3,629.1	0.0
1989	70.6	0.0	3,540.8	685.7	864.5	393.5	3,954.0	49.8
1990	59.5	0.0	3,386.2	707.2	840.7	420.8	3,802.3	78.1
1991	38.9	0.0	3,193.1	730.0	817.0	455.3	3,652.1	84.8
1992	38.2	0.0	3,186.3	772.4	780.2	497.3	3,584.3	255.0
1993	31.7	0.0	3,295.9	818.4	744.4	545.9	3,691.3	360.1
1994	25.8	0.0	3,357.0	862.0	708.7	600.5	3,733.4	463.2
1995	23.0	0.0	3,014.3	890.1	673.9	660.6	3,407.5	507.8
1996	21.5	0.0	2,844.4	919.3	639.2	727.2	3,223.0	606.6
1997	16.7	0.0	3,033.1	948.9	607.4	800.2	3,404.5	744.0
1998	14.4	0.0	3,076.6	948.9	570.6	880.9	3,447.2	870.0

ANNUAL RATE OF INTEREST ON GENERAL + PERMANENT FUNDS	=	0.120
ANNUAL RATE OF INTEREST ON NEW BONDS	=	0.100
MATURITY PERIOD ON NEW BONDS IN YEARS	=	10.000
% OF OPERATING BUDGET IN G.F. CASH BAL	=	0.200
% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

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15-FEB-82

GASLINE DEC 1986-HIGH INFLATION
DEPT OF REVENUE ESTIMATES
BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	434.8	4272.0	1922.2	1390.7	113.2	152.5	3578.6	693.4	4771.9	0.0	0.0
1984	4680.1	678.8	5359.0	2315.7	2742.2	138.8	162.3	5359.0	0.0	5606.2	0.0	0.0
1985	5604.9	964.6	6569.4	2859.2	3314.7	163.8	231.8	6569.4	0.0	6505.0	0.0	0.0
1986	6455.3	1215.7	7671.0	3205.4	4003.1	161.9	300.6	7671.0	-0.0	7459.1	0.0	0.0
1987	7834.1	1483.2	9317.3	3493.9	5298.3	157.8	367.2	9317.3	0.0	8513.6	0.0	0.0
1988	7826.8	1699.7	9526.5	3755.2	5192.8	154.8	423.6	9526.5	0.0	9664.3	0.0	0.0
1989	8474.9	1871.8	10346.7	4209.6	5505.6	146.5	485.0	10346.7	0.0	10944.2	0.0	0.0
1990	8245.7	2000.5	10246.2	4719.0	4840.4	135.4	551.3	10246.2	-0.0	12221.1	0.0	0.0
1991	7976.9	2074.3	10051.2	5290.0	4024.6	114.8	621.7	10051.2	0.0	13474.8	0.0	0.0
1992	8051.9	2137.1	10189.0	5930.1	3449.3	114.1	695.6	10189.0	-0.0	14804.0	0.0	0.0
1993	8353.1	2244.7	10597.8	6647.6	3323.6	31.7	772.7	10775.6	-177.8	16223.2	0.0	177.8
1994	8559.9	2423.7	10983.6	7452.0	3725.8	25.8	852.7	12056.2	-1072.7	17719.4	0.0	1072.7
1995	8048.4	2658.0	10706.4	8353.7	4176.6	23.0	935.0	13488.3	-2781.8	19168.4	0.0	2781.8
1996	7850.7	2917.5	10768.1	9364.5	4682.0	21.5	1019.6	15087.5	-4319.4	20626.0	0.0	4319.4
1997	8315.0	3193.3	11508[illegible]	10497.6	5248.5	16.7	1106.9	16869.7	-5361.4	22205.2	0.0	5361.4
1998	8497.4	3487.3	11984.[illegible]	11767.8	5883.5	14.4	1197.2	18862.9	-6878.2	23872.2	0.0	6878.2

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL
FY 1983 $

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GASLINE DEC 1986-HIGH INFLATION
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BUDGETS AT SPENDING LIMIT
SURPLUS SPENT ON CAPITAL

YEAR END	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF $0 MIL
1982										4005.3	-693.4	
1983	3837.2	434.8	4272.0	1922.2	1390.7	113.2	152.5	3578.6	693.4	4771.9	0.0	0.0
1984	4293.7	622.8	4916.5	2124.5	2515.8	127.3	148.9	4916.5	0.0	5143.3	0.0	0.0
1985	4717.5	811.9	5529.3	2406.5	2789.9	137.9	195.1	5529.3	0.0	5475.1	0.0	0.0
1986	4984.7	938.7	5923.4	2475.2	3091.1	125.0	232.1	5923.4	-0.0	5759.8	0.0	0.0
1987	5549.8	1050.8	6600.6	2475.2	3753.5	111.8	260.1	6600.6	0.0	6031.2	0.0	0.0
1988	5086.9	1104.7	6191.6	2440.7	3375.0	100.6	275.3	6191.6	0.0	6281.1	0.0	0.0
1989	5053.3	1116.1	6169.4	2510.1	3282.8	87.4	289.2	6169.4	0.0	6525.7	0.0	0.0
1990	4510.7	1094.3	5605.0	2581.5	2647.9	74.1	301.6	5605.0	-0.0	6685.3	0.0	0.0
1991	4003.3	1041.0	5044.3	2654.9	2019.8	57.6	312.0	5044.3	0.0	6762.5	0.0	0.0
1992	3707.3	984.0	4691.3	2730.4	1588.1	52.5	320.3	4691.3	-0.0	6816.2	0.0	0.0
1993	3528.5	948.2	4476.6	2808.0	1403.9	13.4	326.4	4551.7	-75.1	6852.8	0.0	75.1
1994	3317.2	939.3	4256.5	2887.9	1443.9	10.0	330.4	4672.2	-415.7	6866.8	0.0	415.7
1995	2861.5	945.0	3806.5	2970.0	1484.9	8.2	332.4	4795.5	-989.0	6815.0	0.0	989.0
1996	2560.7	951.6	3512.3	3054.5	1527.2	7.0	332.6	4921.2	-1408.9	6727.8	0.0	1408.9
1997	2488.2	955.6	3443.8	3141.4	1570.6	5.0	331.2	5048.2	-1604.4	6644.8	0.0	1604.4
1998	2332.9	957.4	3290.3	3230.7	1615.3	4.0	328.7	5178.6	-1888.3	6553.8	0.0	1888.3

ASSUMPTIONS

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% OF ROYALTIES TO PERMANENT FUND	=	0.250
% OF PERMANENT FUND EARNINGS PAID AS DIVIDENDS	=	0.500
% OF GF ADDED TO CAPITAL BUDGET	=	1.000
INFLATION RATE	=	0.090
'1' IF PERMANENT FUND INCOME BASED ON 5 YEAR AVERAGE	=	1.000
PER CAPITA DIVIDEND	=	50.000
NUMBER OF PRIOR YEAR DIVIDEND RECIPIENTS	=	2.966
GROWTH RATE IN DIVIDEND RECIPIENTS	=	0.028

APPENDIX B

Mr. Edwin (Al) Kuhn, Director
Government & Environmental Affairs
Northwest Alaskan Pipeline Company
1801 K Street, N.W.
Washington, D. C. 20006

Dear Mr. Kuhn:

In accordance with our ongoing discussions regarding Northwest Pipeline impact on the State highway system, our Department has prepared an estimate of what the expected cost of that impact will be. We have made every effort to fairly discriminate between the effects of non-pipeline related use and those impacts which can be related to the pipeline construction effort.

As can be seen in the attached report, pipeline related use will be equivalent to many years of expected normal usage, necessitating repair and reconstruction of these routes much sooner than would be normally anticipated.

In addition, certain maintenance costs which are directly related to traffic volume can be expected to increase substantially.

In order to properly protect other highway users and our taxpayers' investment in our present roadway system, gas pipeline project costs must include $300 Million for reimbursement to the State of Alaska to repair pipeline-related damages to our highway system.

We would like to meet with you at your earliest convenience to discuss this proposal.

Sincerely,

Robert W. Ward

Robert W. Ward
Commissioner

Enclosure.

RWW:JCB:rm

DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES
Division of Planning and Programming

NORTHWEST ALASKAN PIPELINE COMPANY HIGHWAY IMPACT REPORT

June 27, 1980

The following analysis has been undertaken to determine the relative impact construction of the Northwest-Alaskan Natural Gas Pipeline will have on the Alaska Road System.

Information received from Northwest Alaskan Pipeline Company officials concerning their line hauling operations (pipe, insulation, equipment and POL products) were analysed to determine the expected traffic in terms of volume and equivalent axle loadings (EAL's). Equivalent axle loadings are used by our Department to develop the design parameters for highway construction, the physical characteristics being directly related to the requirements to sustain a projected number of EAL's over a 20 year design life. The more EAL's in those 20 years, the stronger the road will need to be.

In addition to the line haul traffic, the impact of support traffic for the pipeline, including camp mobilization, hauling from staging areas, and the shipment of foodstuffs and other commodities, will be very substantial. It has been estimated from experience with the Alyeska Pipeline that this will equal approximately 50% of the line haul traffic.

Non-pipeline traffic on roads south of Fairbanks have historically experienced volume increases of 7% to 8% per year, a trend which is expected to continue. North of Fairbanks there is a lack of historical data, but it can be assumed that truck traffic there would level out near the volumes experienced in the past two years. These years should represent the amount of traffic necessary to sustain current levels of activity and should not contain significant levels of pipeline construction traffic.

Assuming an average age of 10 years for these roads, the number of EAL's which could normally be expected in a 20 year life was computed. This 20 year EAL expectancy has been compared in Table 1 to the number of EAL's generated by pipeline related traffic. The comparative usage was then used to allocate estimated highway rebuilding costs to pipeline impact, as shown in Tables 2 and 4. Results of that investigation indicate that the Northwest construction effort will expend between 19% and 96% of the traffic loadings we would normally expect on the routes studied. Applying this to the repair and reconstruction estimates prepared by our Design section results in a cost of $84,700,000 in today's dollars attributable to pipeline related traffic.

This excludes areas where pipeline related gravel hauling is to be done on public highways. These areas total approximately 42 miles. Determination of traffic volumes and equivalent axle loadings in these areas is very difficult due to lack of information on the hauling units which will be utilized. This is complicated by the fact that these areas are isolated sections where enforcement of legal loading regulations will be inhibited by lack of weigh stations. It may be possible to treat these areas as construction haul roads allowing the use of off road equipment, detours and other forms of traffic control. Repair of these sections would become the total responsibility of Northwest Alaskan Pipeline Company and should be done immediately after hauling is finished. Repair cost of these sections is estimated at $4,116,000 in today's dollars.

Another important factor which is left out of this discussion is impact on bridges. Our computations indicate that the 80 ft. pipe hauling units will have one axle group (tri-axle) grossing over 58 kips, or approximately a 40% overload. This problem must be analyzed by our Bridge Design section to determine the impact in this area.

Past research has also indicated that increased frequency of loading may accelerate roadway damage; however, this information is not available in a quantifiable form which could be applied to the situation at hand.

Pipeline related traffic has also been compared on an annual basis to normal traffic in order to determine expected additional maintenance costs. These comparisons are shown in Tables 3-C through 3-D. This information has been analysed by our Maintenance section and applied to historical maintenance costs to arrive at an estimate of increased costs due to pipeline impact. These costs are shown in Table 4. The resulting estimate of pipeline related maintenance costs is nearly $67,000,000 in 1980 dollars. This estimate is based upon the assumption that reasonable load restrictions will continue to be imposed during breakup, periods of excessively wet weather, or other conditions which could lead to extensive sub-base damage.

In summary, our recapitulation of estimated costs for the known impacts of pipeline construction includes the following:

Roadway & bridge repair and reconstruction--------	$112,588,000
Roadway repair in areas impacted by gravel haul----------------------------------	4,100,000
Additional maintenance costs during pipeline construction-------------------------	66,800,000
TOTAL:	$184,488,000

This cost is given in 1980 dollars.

The effect of inflation on these figures is substantial. Using a 10% inflationary constant with 1980 as the base year, the estimated costs for the known impacts of pipeline construction would be:

Roadway repair and reconstruction (1986)		$199,822,000
Roadway repair in areas impacted by gravel haul (1986)		7,300,000
Additional maintenance costs during pipeline construction:		
1982	8,400,000	
1983	25,700,000	
1984	31,100,000	
1985	31,000,000	
	96,200,000	96,200,000
TOTAL:		$303,422,000

APPENDIX C

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES

DEPUTY COMMISSIONER – PLANNING AND PROGRAMMING

POUCH Z
JUNEAU, ALASKA 99811
PHONE:

January 28, 1982

Honorable Vic Fischer
Alaska State Senator
Pouch V
Juneau, AK 99811

Dear Senator Fischer:

Re: Construction Costs Escalation

Mr. Bob Williams of your staff contacted my office on January 18, 1982, requesting a brief explanation of the reasons behind the great increases in construction costs as compared to the consumer price index.

At the current time, the demand for construction-related materials is out-stripping overall population increases. The current availability of low-interest loan programs has greatly stimulated construction associated with smaller development projects, especially housing. Large-scale capital funding by the State and the oil industry has further increased demand for the limited supply of materials.

In a survey conducted by HMS, Inc. of Anchorage during October of 1981, it was found that basic material costs for steel, copper, aluminum, etc., as well as manufactured items, have been increasing at a 30% annual rate. It was also found that some items, such as concrete, have shown surprising price stability. HMS, Inc., determined that the overall annual inflation rate for materials is approaching 20% annually. Material cost increases combined with union contract wage increases could easily result in a construction escalation rate of 2% per month (24% per year) in 1982.

I hope this information helps clarify your observation that construction prices are rising at a much faster rate than the overall consumer price index. If I can be of further help, please contact me.

Sincerely,

John C. Bates
Deputy Commissioner

APPENDIX D

MEMORANDUM

State of Alaska
Department of Revenue

TO: Joe Donohue
Deputy Commissioner

DATE: February 18, 1982

FILE NO:

TELEPHONE NO:

FROM: Chuck Logsdon
Petroleum Economist
Petroleum Revenue Division

C Logsdon

SUBJECT: Gasline Analysis

Subsequent to my memorandum to you on January 25, 1982 I reworked the input assumptions to reflect the possibility of zero wellhead price for the first several years of ANGTS operation.

Milt Barker provided me with numbers published from U.S. Senate Hearings on the ANGTS waiver recommendation. The numbers included Northwest's current cost estimates and wellhead prices from the Federal Inspectors cost of service simulation model.

I ran three cases:

1. Center point cost estimate and Federal ceiling price @ wellhead.
2. Center point cost estimate and cost of service model wellhead (0 for the 1st three years).
3. 40% cost overrun and cost of service model wellhead prices (0 for the 1st four years).

These runs are attached for your information.

I telecopied these numbers to Milt on February 12, 1982 as he needed them for input into his cost-benefit projections which were presented February 16, 1982.

These revenue projections should take care of the problems mentioned in Mary Halloran's memo to you February 8, 1982. As nearly as I can tell the cost of the conditioning plant is handled by the cost of service model as allocated entirely to the consumers through the tariff.

CLL:il

cc: Fred Boetsch, Petroleum Revenue
Mary Halloran, Dept. of Natural Resources
Milt Barker, Legislative Finance

MEMORANDUM

State of Alaska

Department of Revenue

TO: Joseph K. Donohue
Deputy Commissioner

DATE: January 25, 1982

FILE NO:

TELEPHONE NO:

FROM: Charles L. Logsdon
Petroleum Economist
Petroleum Revenue Division

CLLogsdon

SUBJECT: Prudhoe Bay Gas
Revenue Projections

Attached you will find several tables which lay out projected gas revenues under varying assumptions concerning wellhead price, actual construction cost of the Northwest Alaska ANGTS segment, and property tax methodology.

For comparative purposes I have run out the numbers for the following cases:

Case 1 - High price, \$27 B construction cost, and trended depreciation for property tax purposes;

Case 2 - High price, \$24 B construction cost, and trended depreciation;

Case 3 - Low price, \$27 B construction cost, st. line depreciation for property tax;

Case 4 - Low price, \$24 B construction cost, st. line depreciation.

The other assumptions regarding key variables such as number of wells and assumed inflation appear with each output.

Since the algorithm for revenue projection is computerized further sensitivity analyses could be performed.

The various input assumptions are as follows:

ASSUMPTIONS

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1. Volume (bcf/day) is assumed to be the amount delivered from conditioning plant; actual production volume will be closer to 2.4 bcf/d at the wellhead.

2. High price is calculated by inflating the FERC ceiling price of \$1.78/Mcf (1.63/MMbtu) in December 1978 by 7% per annum. All conditioning costs are passed forward to consumer in tariff. Low price is assumed to be \$1.25/Mcf in 1986 inflated at the rate of 7% annually. This is to account for downward pressure on wellhead price to assure marketability downstream.

3. $ELF = \left[1 - \frac{(300 * \text{wells} * \text{days})}{\text{daily prod.} * \text{days}}\right] \exp \left[{}^{460}/{300}\right]$

NOTE: The price and inflation assumptions in this memo were modified to those in the February 18, 1982 memo of Charles Logsdon for use in the benefits analysis.

Column

4. Severance tax is at 10% * ELF * non-royalty production * price

5. Royalties are equal to production * (price - field cost) * .125. Field cost assumed to be $.20/Mcf times 7% annual inflation.

6. Two Ways A. Property Taxes (2%) calculated on inflated undepreciated base assuming an initial cost of $27 B. Inflation is assumed to be 7%.

B. Property taxes (2%) are calculated on a straight line depreciation remaining life basis.

7. Production expenses are assumed to be $500 million and inflated by 3% until 2005 when they are assumed level at $850 million.

8. The production income tax is calculated as .275 * .094 * (Gross production value less royalties less severance tax less production expenses) .275 is a factor used to scale production income tax estimates in line with the current corporate income tax law.

9. ANGST-Northwest income tax is calculated on straight line depreciated equity of 25% of the estimated $27.0 billion construction cost with a rate of return after tax equal to 17.5%. A federal tax rate of 42% and a state tax rate of 9.4% are assumed.

10. $27.0 billion is assumed to be the center point cost of construction; hence, if the NW ANGTS portion of the gas line costs $24 B to build the rate of return would be:

$$R = [(17.5) \times (1.3) + 8(\frac{24.0}{20.77} - 1.3)] / \frac{24.0}{20.77}$$

$$= [22.75 - 1.16] / 1.16$$

$$= 18.61\%$$

CLL:il

cc: Vincent Wright
Milt Barker

INPUT ASSUMPTIONS FOR THE NORTHWEST ALASKA SEGMENT OF ANGTS

RATE OF INFLATION (PERCENT): 8.0%
COST OF CONSTRUCTION: 27000
ECONOMIC LIFE: 25
PERCENT EQUITY: 25.00%
DISCOUNT RATE: 10.00%
CNTR PT RATE OF RETURN: 17.5%
AD VALOREM: ORIGINAL COST

Rate Base = Cost of Construction = Sponsor
Estimate for Centerpoint Rate of Return.
Wellhead Price @ FERC ceiling
8% Inflation

FISCAL YEAR	VOLUME	PRICE	WELLS	ELF	PROD. EXPENSE	FIELD COST
1987	2.000	3.060	550.000	0.840	500.000	0.200
1988	2.000	3.305	555.000	0.839	530.450	0.216
1989	2.000	3.569	560.000	0.837	546.360	0.233
1990	2.000	3.855	540.000	0.843	562.450	0.252
1991	2.000	4.163	520.000	0.826	579.640	0.272
1992	2.000	4.496	500.000	0.805	597.030	0.294
1993	2.000	4.856	490.000	0.773	614.940	0.317
1994	2.000	5.244	480.000	0.748	633.390	0.343
1995	2.000	5.664	470.000	0.719	652.390	0.370
1996	2.000	6.117	460.000	0.660	671.960	0.400
1997	2.000	6.606	450.000	0.589	692.120	0.432
1998	2.000	7.135	440.000	0.576	712.880	0.466
1999	2.000	7.706	430.000	0.535	734.270	0.504
2000	2.000	8.322	420.000	0.511	756.300	0.544
2001	2.000	8.988	410.000	0.461	778.980	0.587
2002	2.000	9.707	400.000	0.406	802.350	0.634
2003	2.000	10.483	390.000	0.359	826.420	0.685
2004	2.000	11.322	380.000	0.314	851.220	0.740
2005	1.600	12.228	370.000	0.260	850.000	0.799
2006	1.280	13.206	360.000	0.229	850.000	0.863
2007	1.020	14.263	350.000	0.212	850.000	0.932
2008	0.820	15.404	340.000	0.193	850.000	1.007
2009	0.660	16.636	330.000	0.172	850.000	1.087
2010	0.520	17.967	320.000	0.149	850.000	1.174
2011	0.420	19.404	310.000	0.167	850.000	1.268
2012	0.340	20.956	300.000	0.186	850.000	1.370
2013	0.270	22.633	300.000	0.186	850.000	1.479
2014	0.210	24.443	300.000	0.186	850.000	1.598
2015	0.210	26.399	300.000	0.186	850.000	1.725
2016	0.210	28.511	300.000	0.186	850.000	1.863

PROJECTED STATE OF ALASKA NATURAL GAS REVENUES FROM
PRUDHOE BAY EXTRACTION & SALE THROUGH ANGTS

FISCAL YEAR	SEV.TAX	ROYALTY	AD VALOREM	PRODUCTION INCOME TAX	PIPELINE INCOME TAX	TOTAL GAS REVENUE	DISCOUNTED CASHFLOW
1987	164.182	260.975	540.000	33.828	211.500	1210.485	621.170
1988	177.018	281.853	518.400	36.789	203.040	1217.101	1188.957
1989	190 859	304.401	496.800	40.426	194.580	1227.066	1709.353
1990	207.[illegible]	328.753	475.200	44.339	186.120	1241.928	2188.170
1991	219.718	355.054	453.600	48.718	177.660	1254.749	2627.952
1992	231.137	383.458	432.000	53.524	169.200	1269.319	3032.396
1993	239.619	414.135	410.400	58.836	160.740	1283.730	3404.246
1994	250.591	447.265	388.800	64.550	152.280	1303.486	3747.495
1995	260.199	483.047	367.200	70.802	143.820	1325.068	4064.706
1996	257.799	521.690	345.600	77.910	135.360	1338.360	4355.972
1997	248.396	563.425	324.000	85.787	126.900	1348.509	4622.767
1998	262.564	608.499	302.400	93.693	118.440	1385.596	4871.979
1999	263.269	657.179	280.800	102.634	109.980	1413.862	5103.157
2000	271.410	709.754	259.200	112.128	101.520	1454.011	5319.286
2001	264.477	766.534	237.600	122.816	93.060	1484.487	5519.086
2002	251.762	827.857	216.000	134.524	84.600	1514.743	5705.966
2003	240.268	894.085	194.400	147.141	76.140	1552.034	5879.294
2004	227.061	965.612	172.800	160.818	67.680	1593.972	6041.123
2005	162.696	834.289	151.200	136.852	59.220	1344.256	6165.193
2006	123.863	720.826	129.600	115.683	50.760	1140.732	6260.906
2007	98.504	620.361	108.000	96.707	42.300	965.071	6334.581
2008	77.824	538.619	86.400	81.268	33.840	817.752	6391.300
2009	60.305	468.204	64.800	67.961	25.380	686.651	6434.586
2010	44.452	398.399	43.200	54.730	16.920	557.702	6466.547
2011	43.442	347.527	21.600	44.815	8.460	465.844	6490.817
2012	42.219	303.838	0.000	36.310	0.000	382.366	6508.927
2013	36.209	260.586	0.000	28.013	0.000	324.808	6522.912
2014	30.416	218.892	0.000	20.015	0.000	269.323	6533.454
2015	32.849	236.403	0.000	23.374	0.000	292.626	6543.867
2016	35.477	255.315	0.000	27.002	0.000	317.794	6554.147

INPUT ASSUMPTIONS FOR THE NORTHWEST ALASKA SEGMENT OF ANGTS

RATE OF INFLATION (PERCENT): 8.0%
COST OF CONSTRUCTION: 27000
ECONOMIC LIFE: 25
PERCENT EQUITY: 25.00%
DISCOUNT RATE: 10.00%
CNTR PT RATE OF RETURN: 17.5%
AD VALOREM: ORIGINAL COST

Wellhead Price from Cost of Service Model for ANGTS, Federal Inspector for ANGTS, October 19, 1981

FISCAL YEAR	VOLUME	PRICE	WELLS	ELF	PROD. EXPENSE	FIELD COST
1987	2.000	0.000	550.000	0.840	500.000	0.200
1988	2.000	0.000	555.000	0.839	530.450	0.216
1989	2.000	0.000	560.000	0.837	546.360	0.233
1990	2.000	0.650	540.000	0.843	562.450	0.252
1991	2.000	2.240	520.000	0.826	579.640	0.272
1992	2.000	3.810	500.000	0.805	597.030	0.294
1993	2.000	5.130	490.000	0.773	614.940	0.317
1994	2.000	5.530	480.000	0.748	633.390	0.343
1995	2.000	5.970	470.000	0.719	652.390	0.370
1996	2.000	6.460	460.000	0.660	671.960	0.400
1997	2.000	6.960	450.000	0.589	692.120	0.432
1998	2.000	7.520	440.000	0.576	712.880	0.466
1999	2.000	8.050	430.000	0.535	734.270	0.504
2000	2.000	8.610	420.000	0.511	756.300	0.544
2001	2.000	9.210	410.000	0.461	778.980	0.587
2002	2.000	9.860	400.000	0.406	802.350	0.634
2003	2.000	10.550	390.000	0.359	826.420	0.685
2004	2.000	11.290	380.000	0.314	851.220	0.740
2005	1.600	12.080	370.000	0.260	850.000	0.799
2006	1.280	12.920	360.000	0.229	850.000	0.863
2007	1.020	13.830	350.000	0.212	850.000	0.932
2008	0.820	14.790	340.000	0.193	850.000	1.007
2009	0.660	15.830	330.000	0.172	850.000	1.087
2010	0.520	16.940	320.000	0.149	850.000	1.174
2011	0.420	18.120	310.000	0.167	850.000	1.268
2012	0.340	19.390	300.000	0.186	850.000	1.370
2013	0.270	20.750	300.000	0.186	850.000	1.479
2014	0.210	22.200	300.000	0.186	850.000	1.598
2015	0.210	23.750	300.000	0.186	850.000	1.725
2016	0.210	25.420	300.000	0.186	850.000	1.863

PROJECTED STATE OF ALASKA NATURAL GAS REVENUES FROM
PRUDHOE BAY EXTRACTION & SALE THROUGH ANGTS

FISCAL YEAR	SEV.TAX	ROYALTY	AD VALOREM	PRODUCTION INCOME TAX	PIPELINE INCOME TAX	TOTAL GAS REVENUE	DISCOUNTED CASHFLOW
1987	0.000	0.000	540.000	0.000	211.500	751.500	385.638
1988	0.000	0.000	518.400	0.000	203.040	721.440	722.195
1989	0.000	0.000	496.800	0.000	194.580	691.380	1015.408
1990	34.992	36.323	475.200	0.000	186.120	732.635	1297.871
1991	118.222	179.571	453.600	19.588	177.660	948.641	1630.363
1992	195.864	320.847	432.000	43.106	169.200	1161.017	2000.299
1993	253.148	439.152	410.400	63.014	160.740	1326.453	2384.526
1994	264.243	473.335	388.800	68.914	152.280	1347.572	2739.383
1995	274.264	510.983	367.200	75.494	143.820	1371.761	3067.772
1996	272.257	552.993	345.600	83.201	135.360	1389.411	3370.148
1997	261.695	595.700	324.000	91.284	126.900	1399.578	3647.047
1998	276.739	643.648	302.400	99.686	118.440	1440.913	3906.208
1999	275.035	688.606	280.800	108.017	109.980	1462.438	4145.329
2000	280.801	736.029	259.200	116.640	101.520	1494.190	4367.430
2001	271.015	786.809	237.600	126.316	93.060	1514.799	4572.126
2002	255.735	841.833	216.000	136.950	84.600	1535.118	4760.709
2003	241.795	900.164	194.400	148.201	76.140	1560.700	4935.005
2004	226.419	962.687	172.800	160.306	67.680	1589.891	5096.420
2005	160.729	823.498	151.200	134.950	59.220	1329.597	5219.136
2006	121.180	704.121	129.600	112.730	50.760	1118.390	5312.975
2007	95.517	600.232	108.000	93.142	42.300	939.190	5384.615
2008	74.725	515.665	86.400	77.195	33.840	787.825	5439.245
2009	57.384	443.939	64.800	63.646	25.380	655.149	5480.545
2010	41.912	374.041	43.200	50.388	16.920	526.462	5510.716
2011	40.568	322.922	21.600	40.437	8.460	433.987	5533.326
2012	39.064	279.540	0.000	31.994	0.000	350.598	5549.931
2013	33.197	237.391	0.000	23.894	0.000	294.482	5562.611
2014	27.624	197.397	0.000	16.198	0.000	241.219	5572.053
2015	29.553	211.023	0.000	18.867	0.000	259.443	5581.285
2016	31.631	225.701	0.000	21.743	0.000	279.075	5590.313

INPUT ASSUMPTIONS FOR THE NORTHWEST ALASKA SEGMENT OF ANGTS

RATE OF INFLATION (PERCENT): 8.0%
COST OF CONSTRUCTION: 29700
ECONOMIC LIFE: 25
PERCENT EQUITY: 25.00%
DISCOUNT RATE: 10.00%
CNTR PT RATE OF RETURN: 17.5%
AD VALOREM: ORIGINAL COST

40% Cost Overrun Case
Rate of Return = 16.00%
Wellhead Price from Federal Inspector
Cost of Service Model

FISCAL YEAR	VOLUME	PRICE	WELLS	ELF	PROD. EXPENSE	FIELD COST
1987	2.000	0.000	550.000	0.840	500.000	0.200
1988	2.000	0.000	555.000	0.839	530.450	0.216
1989	2.000	0.000	560.000	0.837	546.360	0.233
1990	2.000	0.000	540.000	0.843	562.450	0.252
1991	2.000	1.030	520.000	0.826	579.640	0.272
1992	2.000	2.430	500.000	0.805	597.030	0.294
1993	2.000	4.060	490.000	0.773	614.940	0.317
1994	2.000	5.530	480.000	0.748	633.390	0.343
1995	2.000	5.970	470.000	0.719	652.390	0.370
1996	2.000	6.460	460.000	0.660	671.960	0.400
1997	2.000	6.960	450.000	0.589	692.120	0.432
1998	2.000	7.520	440.000	0.576	712.880	0.466
1999	2.000	8.050	430.000	0.535	734.270	0.504
2000	2.000	8.610	420.000	0.511	756.300	0.544
2001	2.000	9.210	410.000	0.461	778.980	0.587
2002	2.000	9.860	400.000	0.406	802.350	0.634
2003	2.000	10.550	390.000	0.359	826.420	0.685
2004	2.000	11.290	380.000	0.314	851.220	0.740
2005	1.600	12.080	370.000	0.260	850.000	0.799
2006	1.280	12.920	360.000	0.229	850.000	0.863
2007	1.020	13.830	350.000	0.212	850.000	0.932
2008	0.820	14.790	340.000	0.193	850.000	1.007
2009	0.660	15.830	330.000	0.172	850.000	1.087
2010	0.520	16.940	320.000	0.149	850.000	1.174
2011	0.420	18.120	310.000	0.167	850.000	1.268
2012	0.340	19.390	300.000	0.186	850.000	1.370
2013	0.270	20.750	300.000	0.186	850.000	1.479
2014	0.210	22.200	300.000	0.186	850.000	1.598
2015	0.210	23.750	300.000	0.186	850.000	1.725
2016	0.210	25.420	300.000	0.186	850.000	1.863

PROJECTED STATE OF ALASKA NATURAL GAS REVENUES FROM
PRUDHOE BAY EXTRACTION & SALE THROUGH ANGTS

FISCAL YEAR	SEV.TAX	ROYALTY	AD VALOREM	PRODUCTION INCOME TAX	PIPELINE INCOME TAX	TOTAL GAS REVENUE	DISCOUNTED CASHFLOW
1987	0.000	0.000	594.000	0.000	212.709	806.709	413.969
1988	0.000	0.000	570.240	0.000	204.200	774.440	775.251
1989	0.000	0.000	546.480	0.000	195.692	742.172	1090.004
1990	0.000	0.000	522.720	0.000	187.184	709.904	1363.703
1991	54.361	69.159	498.960	1.260	178.675	802.415	1644.944
1992	124.921	194.922	475.200	22.154	170.167	987.364	1959.549
1993	200.347	341.515	451.440	46.711	161.659	1201.671	2307.630
1994	264.243	473.335	427.680	68.914	153.150	1387.322	2672.956
1995	274.264	510.983	403.920	75.494	144.642	1409.302	3010.331
1996	272.257	552.993	380.160	83.201	136.133	1424.744	3320.397
1997	261.695	595.700	356.400	91.284	127.625	1432.704	3603.850
1998	276.739	643.648	332.640	99.686	119.117	1471.830	3868.572
1999	275.035	688.606	308.880	108.017	110.608	1491.146	4112.386
2000	280.801	736.029	285.120	116.640	102.100	1520.690	4338.427
2001	271.015	786.809	261.360	126.316	93.592	1539.091	4546.405
2002	255.735	841.833	237.600	136.950	85.083	1557.201	4737.701
2003	241.795	900.164	213.840	148.201	76.575	1580.575	4914.217
2004	226.419	962.687	190.080	160.306	68.067	1607.558	5077.425
2005	160.729	823.498	166.320	134.950	59.558	1345.055	5201.568
2006	121.180	704.121	142.560	112.730	51.050	1131.640	5296.519
2007	95.517	600.232	118.800	93.142	42.542	950.232	5369.000
2008	74.725	515.665	95.040	77.195	34.033	796.658	5424.243
2009	57.384	443.939	71.280	63.646	25.525	661.774	5465.961
2010	41.912	374.041	47.520	50.388	17.017	530.878	5496.385
2011	40.568	322.922	23.760	40.437	8.508	436.195	5519.110
2012	39.064	279.540	0.000	31.994	0.000	350.598	5535.716
2013	33.197	237.391	0.000	23.894	0.000	294.482	5548.395
2014	27.624	197.397	0.000	16.198	0.000	241.219	5557.837
2015	29.553	211.023	0.000	18.867	0.000	259.443	5567.069
2016	31.631	225.701	0.000	21.743	0.000	279.075	5576.097

APPENDIX E

STATE OF ALASKA

THE LEGISLATURE

1981

Source

FSS-FCCSSJR 4

Legislative Resolve No.

1

Proposing amendments to the Constitution of the State of Alaska relating to limiting increases in appropriations.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. Article IX, Constitution of the State of Alaska, is amended by adding a new section to read:

SECTION 16. APPROPRIATION LIMIT. Except for appropriations for Alaska permanent fund dividends, appropriations of revenue bond proceeds, appropriations required to pay the principal and interest on general obligation bonds, and appropriations of money received from a non-State source in trust for a specific purpose, including revenues of a public enterprise or public corporation of the State that issues revenue bonds, appropriations from the treasury made for a fiscal year shall not exceed $2,500,000,000 by more than the cumulative change, derived from federal indices as prescribed by law, in population and inflation since July 1, 1981. Within this limit, at least one-third shall be reserved for capital projects and loan appropriations. The legislature may exceed this limit in bills for appropriations to the Alaska permanent fund and in bills for appropriations for capital projects, whether of bond proceeds or otherwise, if each bill is approved by the governor, or passed by affirmative vote of three-fourths of the membership of the legislature over a veto or item veto, or becomes law without signature, and is also approved by the voters as prescribed by law. Each bill for appropriations for capital projects in excess of the limit shall be confined to capital projects of the same type, and the voters shall, as provided by law, be informed of the cost of operations and maintenance of the capital projects. No other appropriation in excess of this limit may be made except to meet a state of disaster declared by the governor as prescribed by law. The governor shall cause any unexpended and unappropriated balance to be invested so as to yield competitive market rates to the treasury.

* Sec. 2. Article XV, Constitution of the State of Alaska, is amended by adding new sections to read:

SECTION 26. APPROPRIATIONS FOR RELOCATION OF THE CAPITAL. If a majority of those voting on the question at the general election in 1982 approve the ballot proposition for the total cost to the State of providing for relocation of the capital, no additional voter approval of appropriations for that purpose within the cost approved by the voters is required under the 1982 amendment limiting increases in appropriations (art. IX, sec. 16).

SECTION 27. RECONSIDERATION OF AMENDMENT LIMITING INCREASES IN APPROPRIATIONS. If the 1982 amendment limiting appropriation increases (art. IX, sec. 16) is adopted, the lieutenant governor shall cause the ballot title and proposition for the amendment to be placed on the ballot again at the general election in 1986. If the majority of those voting on the proposition in 1986 rejects the amendment, it shall be repealed.

SECTION 28. APPLICATION OF AMENDMENT. The 1982 amendment limiting appropriation increases (art. IX, sec. 16) applies to appropriations made for fiscal year 1984 and thereafter.

* Sec. 3. The amendments proposed by this resolution shall be placed before the voters of the state at the next general election in conformity with art. XIII, sec. 1, Constitution of the State of Alaska, and the election laws of the state.

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MAJOR ISSUES ASSOCIATED WITH THE ALASKA NATURAL GAS TRANSPORTATION WAIVERS

Prepared at the request of the
House Energy and Commerce Subcommittee on Fossil and Synthetic Fuels

Prepared by

Gary J. Pagliano
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Environment and Natural Resources Policy Division

Joseph P. Riva
Science Policy Research Division

Congressional Research Division
December 18, 1981

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I. FOREWORD

When oil and gas were first located in 1969 at Prudhoe Bay on the North Slope of Alaska, the euphoria of discovery soon gave way to the sobering reality of the transportation problem that this presented. The first priority was to provide a system for moving the oil to market; this was accomplished through the completion of the Trans Alaska Pipeline System (TAPS) in 1977. The delivery of North Slope gas, yet to be realized, will be even more difficult and considerably more costly.

Several gas delivery systems (Arctic Gas, El Paso, Alcan) were proposed and later rejected, providing an opportunity for the Alaska Natural Gas Transportation System (ANGTS) to become the pipeline proposal selected. Its construction has been uncertain because of its high cost, which is already estimated to be five times that of the TAPS (the current record holder for the most expensive privately financed project in history). The costs for the ANGTS are higher for a variety of reasons including the length of the line, the large number of pump stations, the need for a gas conditioning plant, inflation, the extremely harsh climate, and the difficulty in supplying material and labor for construction. These costs have led the sponsors to request Congressional approval of waivers which would permit the North Slope gas producers to own equity in the pipeline and to finance a proportionate amount of its construction cost, to include in the rate base the cost of building a gas conditioning plant, and to permit pre-billing to consumers for segments that are completed before a certain date if the rest of the ANGTS is not finished by that time. It is generally conceded that financing would not be possible without the waivers, and it is far from certain that it will be forthcoming even with them.

The Congressional Research Service, at the request of the House Energy and Commerce Subcommittee on Fossil and Synthetic Fuels has examined various aspects of the ANGTS proposal and the alternatives to it. The report, originally written as a series of "white papers" and provided to the Subcommittee for use during its hearings on ANGTS, analyzes the pre-billing commencement waiver, the regulatory economics of the ANGTS, the potential consequences of not having a pipeline, the methanol alternative to the ANGTS, and the natural gas resources of Alaska.

This report is prepared for use by the Congress in its consideration of this complex and highly controversial issue. The decisions made by Congress on this matter could well have a major impact on U.S. energy policy for decades. The purpose of this report is to provide information on which those decisions can be based.

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II. Executive Summary

THE CONTROVERSIAL PROVISION OF THE WAIVERS PACKAGE: PRE-BILLING COMMENCEMENT

The pre-billing commencement provision of the President's waiver package potentially imposes direct liability on 38 million residential, commercial, and industrial gas consumers, and indirect liability on many more if industrial consumers buying high-priced Alaskan gas pass the extra cost on to customers buying their products. The potential consumer liability of the project depends on four factors: (1) the cost of building the project, (2) the order in which the project segments are completed, (3) the length of time the project remains inoperative, and (4) whether or not the Federal Energy Regulatory Commission (FERC) approves pre-billing commencement.

The final tariff plan of FERC will set a specific date as reasonable time for completing the entire project. If the Canadian segment of the pipeline is finished by that time, the Canadians could be permitted to begin charging U.S. consumers a rate covering their debt, equity and operating costs. The U.S. part of the project will be divided into two segments, the conditioning plant and the pipeline. The rate set by the FERC may allow each of the segments, if completed, to recover debts and operating expenses starting on the fixed date. When the entire system is completed and gas is flowing, the U.S. pipeline consortium will also be allowed to recover equity costs.

The intent is to give the U.S. sponsors an incentive to finish on time while giving their lenders some assurance of payment. The Canadians would be discouraged from moving too rapidly to complete their portion before the fixed date. The FERC could adjust the fixed date for completion if necessary.

The consumer may be called upon to assume financial risk which could run into the billions of dollars if the project is abandoned; but, re-receives little immediate compensation in return. An added consideration might be to either reduce the consumer's risk or increase the consumer's compensation for assuming a greater risk. Reducing consumer risk might include: (1) the gas producers risking more equity than the approximate $3 billion each has pledged; or (2) the State of Alaska, which could realize $10.7 billion (1980 dollars) from natural gas sales through royalties and severance taxes, assuming part of the risk. On the other hand, if consumers do take on the burden of increased liability, then their tariff could be reduced (by reducing rate of return on equity) proportionately to compensate them for their increased risk.

THE REGULATORY ECONOMICS OF THE ANGTS

A number of proposals have recently been made regarding the decontrol of gas prices. Even though the Natural Gas Policy Act (NGPA) provides for phased deregulation by 1985, many categories of gas still remain under price controls for the duration of their well's production life. Additionally, some gas is sold under contractual bases which prohibit price escalation, although many gas supply contracts have deregulation clauses in them which would allow the prices of older, flowing gas to rise to market levels if price controls were lifted. This deregulation could remove some of the inherent protection for Alaskan gas and its expensive transport system provided by the NGPA and by the supply of old gas under contracts which could ensure that its price remains well below market clearing levels which would prevail under deregulation.

There is a likelihood that the economic viability of the ANGTS project hinges upon the wellhead pricing issue to a large extent. The capital cost of the pipeline, including interest accrued during the construction period and amortized like a mortgage, results in an estimated fixed transport cost of $13.00 per mcf. The wellhead price actually paid for the gas itself, presently controlled under the NGPA, plus operating costs, would be additional. Whether or not the waiver package is passed, however, the project partners will be able to charge ANGTS fixed costs to all of their ratepayers equally. This means that the Alaskan gas can be "rolled in" (averaged) with the lower cost "Lower-48" gas for delivery and pricing; thus, spreading the pipeline costs to <u>all</u> of the partners' gas customers. These consumers would see the price of all purchased gas (whether Alaskan gas or not) rise by about $1.10 per mcf, assuming the ANGTS costs were allocated equally both among the partners' customers. Those customers who are the direct beneficiaries of the extra gas supply will not pay its real transportation cost. They will pay only a fraction of the costs involved. The rest of the partners' customers will pay a higher price for the bulk of their gas because of the higher ANGTS costs.

Also effecting ANGTS is what might happen to the NGPA in the near future. Not only does the 1978 law control Prudhoe Bay gas at a relatively low wellhead price, but it also controls a great deal of Lower-48 gas which will be flowing into the 1990s. The controlled Lower-48 gas provides a cushion of the ANGTS partners, giving them substantial quantities of low-priced gas with which to blend their higher-cost Alaskan supplies in order to make their product more competitive. A change in the law could cause this gas to be decontrolled, and its price determined in a way which does not appear to be well understood or much discussed.

One possible outcome of decontrol is that with transport costs already being paid by customers of the several ANGTS partners, and the partners' need to bid for other gas supplies in competition with pipeline companies not burdened with ANGTS project amortization, even the price of Prudhoe Bay gas will be determined in the Lower-48 market place, where most of the bidding for supplies occurs. If this were the case, the ANGTS parnters could end up paying the Lower-48 market clearing price (indeed, most of their supplies will still be purchased there) for Alaskan gas as well, in spite of its vastly higher, but disguised, transport cost.

THE POTENTIAL CONSEQUENCES OF NOT HAVING A PIPELINE

There are several facets of the decision on the ANGTS which are likely to affect U.S.-Canadian relations. First, there is the timeframe during which the decision is made. If the U.S. Congress does not approve the current waiver package, the project would probably be abandoned because of financial difficulties. A quick decision (even a positive one), however, could be just as damaging to U.S.-Canadian relations if financing cannot be arranged with the waivers. A longer timeframe could provide opportunities to improve country relations in general and to address the consequences of the ANGTS, whether it is completed or not.

Second, the U.S. Government handling of the ANGTS decision is very important. Even though the project has been touted a private sector project, the U.S. Government has provided official assurances to Canada that the ANGTS waivers would be sought. If the waiver package fails, the Canadian Government would surely question the level of U.S. Government support.

And third, some alternatives to the ANGTS could involve Canadian gas because of its proximity to Alaskan gas resources, and the potential economies of scale of joint transportation facilities. Frequent and explicit communication between the two countries is essential to any future joint venture. The Canadians should appreciate, however, that any action in the United States on the ANGTS has to be viewed with the same understanding that they are demanding of Americans concerning the Canadian National Energy Plan.

THE NET NATIONAL ECONOMIC BENEFIT(NNEB): IS THERE A LOSS?

Analysis of several major factors affecting the potential quantitative economic benefits of the ANGTS shows that most of the factors create large uncertainties concerning the project's economic viability. One of these uncertainties is the choice of an appropriate discount rate. If ten percent is used, the NNEB estimates in all three cited studies fall within the range of $9-13 billion. A ten percent discount rate would be reasonable for a normal project during most historical capital market situations, but the ANGTS is not a normal project. If a higher discount rate is assumed, based on extremely high rates of return in light of the great risk involved, the NNEB would be lower and might disappear completely. If somewhat lower discount rates are assumed, the result would be more favorable to the ANGTS.

Stable (increasing at a low rate) world oil prices, while good for the United States in general, would be bad for the ANGTS because they would delay the time when the initially expensive Alaskan gas could be competitive with oil. The prospects for finding more gas in Alaska are good, but location and quantity are factors which would influence potential further utilization of the ANGTS. There is still considerably uncertainty over whether or not those future gas supplies exist in quantities sufficient to warrant development. However, it should be pointed out that some benefits associated with ANGTS are difficult to quantify. The most important is the national security benefit to the United States.

THE METHANOL ALTERNATIVE TO THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

The prolonged difficulties associated with construction of the Alaska Natural Gas Transportation System (ANGTS), including the need for special legislative treatment by Congress, have prompted a review of alternative delivery systems. One of the potential alternatives is the conversion of the gas to methanol, which could be done incrementally, would have long-term flexibility, would be entirely on U.S. territory, and could cost less than the ANGTS. If the ANGTS line is not financed, methanol is considered by some to be the most practical alternative.

The methanol alternative consists of three major components, production, transportation, and market. The production of methanol on the North Slope would require the construction of approximately 17 barge-mounted methanol plants that would be towed to Prudhoe Bay. Each plant would produce about 3,000 metric tons/d (24,000 b/d) from 100 million cubic feet of gas. With all 17 plants operating, the total daily production would be about 51,000 tons (408,000 b/d). The conversion process would consume about 22 percent of the feedstock in processing, but it would convert to methanol all of the carbon dioxide and natural gas liquids in the gas stream in contrast to the ANGTS, which would remove these gases prior to transportation. The total resource cost (the total raw material consumed or lost between the time of its production and its end use) for methanol, however, is less than half that of natural gas moved through the ANGTS (16 percent versus 40.4 percent).

The transportation of methanol from the North Slope can be accomplished several ways. The one most often mentioned is to batch the methanol through the Trans-Alaska Pipeline (TAPS). This would utilize spare capacity and, except for additional storage tanks, would require little additional capital outlay. If additional oil were discovered in large quantities, the North Slope producers would probably want to use that capacity for oil. The methanol could be commingled with the crude, but this would require a distillation step to separate the methanol from the crude after shipment. A line dedicated to methanol and sized to its production level could be built parallel to the TAPS line, although this would probably cost about $5 billion. A fourth possibility is to use an all-marine route with ice-breakers escorting conventional tankers or icebreaking tankers by themselves to Prudhoe Bay. Submarine tankers might also be a possibility, although the costs and reliabilities are uncertain.

The market for methanol has grown in recent years and is likely to increase at an even greater rate in the future. The largest market for fuel-grade methanol is octane boosting for gasoline. Methanol additives of up to 12.6 percent total fuel volume are currently being marketed, and wider use is expected. Methanol has a blending octane value of about 120, costs less than conventional octane boosters, and displaces a like amount of petroleum-based fuel. The major advantages of methanol as a fuel are that its combustion produces very little pollution, it is cost-competitive, and it can be made from any hydrocarbon. Major disadvantages of North Slope methanol, however, include a limited market distribution system, required modifications in automobiles and power plants consuming methanol, and the prospects of strong competition from methanol using Southwestern coal as a feedstock.

The cost of methanol versus the cost of natural gas through the ANGTS is also an important consideration. After using the model of the Jet Propulsion Laboratory (of the California Institute of Technology) with CRS assumptions, estimates showed that first-year costs (1987 dollars) of converting Alaska gas to methanol and transporting it to Long Beach could be between $14.24 and $17.24 per million Btu's (mm/Btu's). The Office of the Federal Inspector has estimated that first-year costs (1987) for the ANGTS would be $15.15 mm/Btu's.

III. INTRODUCTION *

Thirteen years ago, a huge natural gas deposit (26 trillion cubic feet) was discovered at Prudhoe Bay. Today, there is still doubt about when or if a tranportation system will be built to bring the gas to the Lower 48 States. The Alaska Natural Gas Transportation System (ANGTS) project is currently two years behind schedule, and its costs have soared from $10 billion to about $44 billion. Even though preliminary construction has started, completion of the project remains uncertain because attempts at financing the project have so far been unsuccessful.

The Nation's need for development of new gas resources is readily apparent. Proven reserves of conventional gas in the Lower 48 States continue to decrease because the United States is consuming more gas than it is discovering. In 1973, the United States consumed 300 percent more gas than it found and in 1979, 40 percent. Consequently, U.S. proven gas reserves, which were 292 trillion cubic feet (tcf) 13 years ago, are today only 195 tcf of which 32 tcf is in Alaska.

There is little doubt, therefore, about the potential demand for Alaskan gas, providing the price is right. Some experts maintain, however, that Alaskan gas will be too expensive to compete with gas produced in the Lower 48, as well as most residual and distillate fuel oil. This will especially be true, they contend, because oil prices will moderate during the 1980s,

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* Prepared by Gary Pagliano, Analyst in Energy Policy, Environment and Natural Resources Policy Division, Congressional Research Service.

mainly due to decreasing oil demand. Proponents of the ANGTS concede that Alaskan gas will be expensive in the first years of the project, but they claim that in the later years its price will be significantly lower than the alternatives. Moreover, ANGTS advocates claim that the average price of Alaskan gas during the life of the project would be less than the average price of its energy competitors over the same time period.

The risks associated with the ANGTS are substantial, but so are the potential benefits. Many of the potential benefits of the ANGTS depend on the project's final cost and the future behavior of the world gas and oil markets. Also such domestic factors as future gas deregulation, national security considerations, and any future discoveries of other Alaskan gas resources would influence the magnitude of benefits. Two Federal government-sponsored studies have already shown that the economic benefit to the nation could run into billions of dollars. 1/

The principal risk is in the decision to commit a great deal of money to a project which has a high probability of some cost overruns and some probability (its magnitude is controversial) of large cost-overruns. Specifically, investors may be unwilling to finance a project costing about $45 billion because any construction delays or other problems associated with a project of this nature could cause project costs to rise by large increments This could result in project abandonment or, more likely, in a project that could never pay for itself. To complicate matters, the current project sponsors apparently do not have sufficient borrowing capacity to rescue the project if the worst began to happen.

1/ Executive Office of the President. Decision and Report to Congress on the Alaska Natural Gas Transportation System. September 1977.

To strengthen the financial safety net for the project, the sponsors have urged the Alaskan gas producers (Exxon, ARCO, and Sohio) with their large financial assets to participate in the project. Recently, the gas producers and the sponsors agreed on producer participation and a financing plan for the project. The plan contained regulatory conditions which must be ratified by the Federal Government.

These conditions, known as the "waiver package," involve overriding certain Federal regulations that would apply directly to this project. If the rate of return is high enough with the waivers, then financing probably could be obtained. Because the rate of return is generally accepted as adequate, especially when the investment tax credit is also considered, then risk reduction becomes the main problem facing the project. The "waiver package" reduces the project risk. The waiver package, as proposed, consists of the following elements:

-- Producer ownership: The gas producers participate in ownership of the Alaska segment provided there is no inconsistency with antitrust laws and no restrictions on access to the pipeline or capacity expansion.

-- Conditioning plant: The gas conditioning plant would be included as part of the pipeline for all legal purposes.

-- Hearings: Requirements for formal FERC evidentiary hearings are eliminated unless FERC determines that such a hearing is necessary.

-- Revisions: FERC would have no authority to change any final tariff rule or order in a way that would impair recovery of operating and debt costs. Nor could FERC change orders to allow purchasers of Alaska gas to recover all cost approved under the tariff.

-- Shipper status: The U.S. pipeline consortium and any other shipper of gas to the Alaska segment would be considered a "natural gas company" for purposes of the Natural Gas Act.

-- Import, export: Gas transported to the Alaska segment would be free of export restrictions if delivered to Canada and replaced by Canadian downstream gas. Such Canadian gas would also be free of U.S. import rules.

-- Pre-Billing commencement: FERC's final tariff plan would set a specific date as reasonable time for completing the entire project. If the Canadian segment of the pipeline is finished, the Canadians on that date could start charging U.S. consumers a rate covering their debt, equity and operating costs.

The U.S. part of the project would be divided into the conditioning plant segment and the pipeline segment. The rate set by FERC would allow each segment, if complete, to recover debt and operating expenses starting on the fixed date. When the entire system is completed and gas is flowing, the U.S. pipeline consortium would be allowed to recover equity costs also.

IV. THE CONTROVERSIAL PROVISION OF THE WAIVER PACKAGE: PRE-BILLING COMMENCEMENT *

A. Introduction

The pre-billing commencement provision of the President's waiver package potentially imposes direct liability on 38 million residential, commercial, and industrial gas consumers and indirect liability on many more if industrial consumers buying high-priced Alaskan gas pass the extra cost on to customers buying their products. How great is the potential consumer liability of the project? The answer depends on four factors: (1) the cost of building to project, (2) the order in which the project segments are completed, (3) the length of time the project remains inoperative, and (4) whether or not the Federal Energy Regulatory Commission (FERC) approves pre-billing commencement.

B. Pre-Billing Commencement

The provision would work in the following manner. The final tariff plan of FERC will set a specific date as reasonable time for completing the entire project. If the Canadian segment of the pipeline is finished by that time, the Canadians would be permitted to begin charging U.S. consumers a rate covering their debt, equity and operating costs. The U.S. part of the project will be divided into two segments, the conditioning plant and the pipeline. The rate set by the FERC may allow each of the segments, if completed, to recover debts and operating expenses starting on the fixed date. When the entire system

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is completed and gas is flowing, the U.S. pipeline consortium will also be allowed to recover equity costs.

The intent is to give the U.S sponsors an incentive to finish on time while giving their lenders some assurance of payment. The Canadians would be discouraged from moving too rapidly to complete their portion before the fixed date. The FERC could adjust the fixed date for completion if necessary.

C. Impact of Pre-Billing

In order to estimate the potential consumer liability, CRS analyzed data contained in the Office of the Federal Inspector's (OFI), Cost of Service Model (see Table 1). Calculations were made by the OFI in Table 1 to determine the first-year cost-of-service charges for each major segment -- the Alaskan gas conditioning plant, the Alaskan pipeline segment and the Canadian pipeline segment. High and low assumption cases were examined -- Case I (the Alaska plant is completed last) and Case II (the Alaska pipeline is completed last -- it is commonly accepted the Canadian pipeline segment will be completed first).

Table 2. shows a wide range of potential consumer liability. Total annual liability ranges from \$1.7 billion (low assumptions -- Case II) to \$2.9 billion (high assumptions -- Case I). The average monthly charge per customer ranges from \$1.37-\$2.30 for residential, \$8.79-\$14.82 for commercial, and \$387.00-\$610.00 for industrial customers (1980 dollars). The estimates for 1987 would be double the 1980 estimates assuming a 10 percent inflation rate. For example, the average monthly charge to industrial customers would range from \$744-\$1220.

TABLE I

BILLING COMMENCEMENT

	Low Assumptions		High Assumptions	
1980 Dollar Estimate	$ 19.1 B		$ 22.5 B	
Interest Rate	8%		14%	
Construction Escalation Rate	7%		11%	
General Inflation Rate	5%		11%	
ANGTS Costs in millions of 1987 dollars:				
Alaska Plant (min. bill)				
Operations & Maintenance	$ 92.45		$ 140.35	
Ad Valorem Tax	107.12		148.97	
Interest	257.91		652.02	
Debt Repayment	165.33		238.84	
Subtotal	622.81		1,180.18	
1980 Dollars		432.0		539.5
Alaska Pipeline (min. bill)				
Operations & Maintenance	$ 55.44		$ 84.08	
Ad Valorem Tax	330.91		500.48	
Interest	659.67		2,036.41	
Debt Repayment	422.86		745.94	
Subtotal	1,468.88		3,366.91	
1980 Dollars		1,018.7		1,539 [illegible]
Canada (Full Cost of Service)				
Canadian dollars	$2,350.85		$4,052.95	
U.S. Dollars	1,880.2		3,249.7	
1980 Dollars		1,304.0		1,389.0
23.5% Share of ANGTS costs (residential sales to total sales)				
Alaska Plant	$ 101.5		$ 126.8	
Alaska Pipeline	239.4		361.7	
Canada	306.4		326.4	
80.5% U.S. customers affected by Alaskan gas (in millions)	34.9		34.9	
Monthly average increase in customer's bill (1980 $)				
Alaska Plant	$ 0.24		$ 0.30	
Alaska Pipeline	0.57		0.86	
Canada	0.73		0.78	

Source: Office of the Federal Inspector.

The impact on the industrial sectors is especially noteworthy because most companies would either pass the increased cost to their customers through products price increases or, more likely in many cases, switch to a cheaper source of energy such as residual oil. If massive switching occurs in the industrial sector, then the average monthly cost to consumer in the residential and commercial sectors could skyrocket because the industrial sector is planned to bear 50 percent fo the consumer liability. The length of time two of the three project segments could remain idle and still be paid for by the consumer is difficult to estimate. Much depends on the FERC's decisions setting completion dates for each of the three segments. A project delay of one year, however, is not unreasonable considering the Artic weather factor, the technical complexities of the conditioning plant and Alaska's pipeline segment, and the past experience of some delays in the Trans Alaska Oil Pipeline System (TAPS).

Thus, the consumer may be called upon to take on a financial risk which could run into the billions of dollars if the project is abandonned and receives little immediate compensation in return. 1/ An added consideration might be to either reduce the consumer's risk or increase the consumer's compensation for assuming a greater risk. Reducing consumer risk might include: (1) the gas producers risking more equity than the approximate $3 billion each has pledged; or (2) the State of Alaska, which could realize $10.7 billion (1980 dollars) from natural gas sales through royalties and severance taxes,

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1/ It is unclear when gas from ANGTS will become competitive with gas from the Lower 48 States or other energy competitors such as residual oil; 5-10 years is a reasonable estimate. After gas from ANGTS under prices its competitors, can consumers claim compensation for the extra risk.

TABLE III

POTENTIAL CONSUMER LIABILITY

	Low Assumptions (Million 1980 dollars)		High Assumptions (Million 1980 dollars)	
First Year Costs				
Alaska Plant	$ 432.0		$ 539.5	
Alaska Pipeline	1,018.7		1,539.3	
Canada Pipeline	1,304.0		1,389.0	
Case I				
	1,018.7		1,539.3	
	1,304.0		1,389.0	
Total Annual Cost	2,322.7		244.0	
Total Monthly Cost	193.6			
Market Distribution*	Monthly Total	Monthly Average Per Consumer (1980 dollars)	Monthly Total	Monthly Average Per Consumer (1980 dollars)
Residential	63.9	$ 1.83	80.5	$ 2.30
Commercial	32.9	11.75	41.5	14.82
Industrial	96.8	484.00	122.0	610.00
Case II				
	432.0		539.5	
	1,304.0		1,389.0	
Total Annual Cost	1,736.0		1,928.5	
Total Monthly Cost	144.7		160.7	
Market Distribution*	Monthly Total	Monthly Average Per Consumer (1980 dollars)	Monthly Total	Monthly Average Per Consumer (1980 dollars)
Residential	47.8	1.37	53.0	1.52
Commercial	24.6	8.79	27.3	9.75
Industrial	77.4	387.00	80.4	402.00

*Based on 1979 interstate market distribution contained in AGA's Gas Facts.

assuming part of the risk. 2/ On the other hand, if consumers do take on the burden of increased liability, then their tariff could be reduced (by reducing rate of return on equity) proportionately to compensate them for their increased risk.

It is conceivable that potential consumer inequities could be resolved within the confines of the proposed waiver package. Several questions, however, should be answered, concerning consumer liability impact:

(1) What will be the FERC's policy in detail that will determine projected completion dates for each segment?

(2) What are reasonable estimates for delays for each segment?

(3) Should the consumer receive compensation for assuming increased financial risk? If so, how?

(4) Should the State of Alaska assume some risk in the project or should the producer assume more risk in the project to reduce risk to the consumer.

(5) If industrial customers balk at paying either any "idle" costs or the high initial delivered costs of Alaskan gas, what additional financial burden would the residential and commercial sectors have to bear?

2/ Decision and Report to Congress on the Alaskan Natural Gas Transportation System. Executive Office of the President. September 1977, p. 118 (translated to 1980 dollars).

V. Regulatory Economics of the Alaskan Natural Gas Transportation System (ANGTS)*

A. Introduction

The economics of the ANGTS project depend in important respects on a number of regulations in existing law that are essentially nonmarket in nature. The most important for ANGTS involves the set of regulations contained in the Natural Gas Policy Act (NGPA). NGPA imposes below-market price controls on gas wellhead prices in Alaska and the Lower 48 States, and it would permit the pipeline partners in the ANGTS project to average (or "roll-in") the high price of Alaskan gas with their Lower-48 supply. Since the partners would receive only about 10 percent of their gas supply from Prudhoe Bay (Alaska), there will be a significant dilution of the price actually paid for the Alaskan gas, at least as perceived by the consumer.

The result is that the NGPA, as it stands today, would probably reduce the effective price of Alaskan gas at the burner tip. However, there is a good chance that this regulatory arrangement could change. This section of the report will analyze the current NGPA-ANGTS relationship and its impact on the consumer, and it will then discuss possible changes in NGPA and the implications for ANGTS.

B. Current Pricing Under the Natural Gas Policy Act of 1978 (NGPA)

NGPA currently controls the average price of gas produced in the United States at about $2.25 per mcf, as indicated by the most recent data on the acquisition cost of gas by interstate pipelines (the June, 1981 data showed

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$2.16). Nearly all gas currently flowing is still under one form of price ceiling or another, as provided for in NGPA Title I. Even though a popular perception exists that gas will be completely deregulated in 1985 under existing law, gas supply contracts and older flowing gas which is controlled by NGPA in perpetuity will cause between 40 and 60 percent, according to most estimates, of the flowing gas in the Lower-48 to remain controlled in 1985 at prices substantially under oil-equivalent levels (or at least those expected based on current perceptions). One producer, CONOCO, has indicated that an analysis of its gas supply and related contracts showed that 70 percent of its 1985 gas output would effectively be under residual NGPA controls.

The fact that large quantities of gas will remain controlled for such a long period of time under the current NGPA provides the ANGST partnership pipelines with a "cushion" of gas priced well below market clearing levels, assuming these NGPA provisions are not ammended. Rolling-in the price of Alaskan gas and its transportation cost with the much lower-priced gas in the Lower-48 would enable the ANGST partnership pipelines to sell gas from Prudhoe Bay at a lower perceived price. How long into the future this could prevail (perhaps into the early 1990's) will depend upon the longevity of the controlled categories of gas. In any event, the existence of significant amounts of controlled gas in the Lower 48 at low prices could prove to be tacitly advantageous for Alaskan Gas.

1. Prudhoe Bay Gas Under NGPA

Section 109(a)(4) provides that "natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976" be subject to a ceiling price of $1.45 per mcf plus inflation adjustment after

April 1977. This would result in a current (October 1981) price of $2.09 per mcf at the wellhead. Section 109(b) further provides that this price can be increased if such a rise is "just and reasonable":

> The Commission may, by rule or order, prescribe a maximum lawful ceiling price, applicable to any first sale of any natural gas (or category thereof, as determined by the Commission) otherwise subject to the preceding provisions of this section if such price is --
>
> (A) higher than the maximum lawful price which would otherwise be applicable under such provisions; and
>
> (B) just and reasonable with the meaning of the Natural Gas Act.

It is noteworthy that gas in this category can never be deregulated under present law. Also of note is the specificity with which Sec 109(b) singles out Prudhoe Bay gas tranported via the ANGST. This conveys an impression that the NGPA's framers held special concerns regarding Alaskan gas and its pricing via-a-vis the viability of the ANGTS.

In summary, there are two important factors at work here which will make Prudhoe Bay gas tranported via the ANGTS more marketable than it would otherwise be: (1) the contolled, lower well-head price; and (2) the "cushion" resulting from rolling-in lower priced gas from the Lower-48 states. Absent these provisions, the ANGTS partner pipelines would lose two potential benefits: (1) the controlled wellhead price would be replaced by a presumably higher market price, and (2) the commercial advantage stemming from the ability to roll-in high-priced Prudhoe Bay gas with enough low-priced NGPA gas from the Lower-48 to make the apparent price of ANGTS supplies far lower than it would otherwise be. Without these implicit and explicit protections from the NGPA, the delivered gas prices of the ANGTS partners (as perceived by their customers) could be much higher than those which could be expected in a nonutility market and too high for competitive success.

2. The Potential Value of the NGPA Cushion

A number of factors make forecasts of gas prices even four or five years into the future extremely uncertain, but a calculation can be made which highlights the benefits of the NGPA cushion to ANGTS partners. It is important to note that these calculations are done for illustrative purposes. Even though they are based on fairly realistic assumptions, they should not be viewed as embodying projections of mathematical precision. They are designed to illustrate the general order of magnitude of the effects involved. Some reasonable assumptions have been made and used to approximate the benefits of rolled-in pricing of specified quantities of ANGTS gas with specified quantities of controlled NGPA gas in 1987. The example is framed in terms of 1980 constant dollars and is based on the following circumstances assumed to exist in 1987:

--The ANGTS partners will continue to have their 1980 levels of domestic supply -- 7.8 tcf -- and at least 40% of this will be under NGPA controls at an average price of $1.25 per mcf.

--ANGTS gas would be priced at $9.06 per mcf (cost estimate center point plus 10%).

--Uncontrolled Lower-48 gas will sell at the equivalent of 1% sulfur residual fuel oil, i.e, $30.00 per barrel or $4.80 per mcf equivalent.

--There will be no energy price increases in real dollars during the period prior to the ANGTS start-up.

Under these assumption, two scenarios are examined: one with no controlled "old" gas, and one in which there was a mix of uncontrolled, controlled, and ANGST gas as well. With the former, the ANGTS partners would have a weighted average price of flowing gas on their systems of $5.15 per mcf 1/

1/ Based on the weighted average prices of $1.25 (weight - 40%), $4.80 (weight - 50%), and $9.06 (weight - 10%) per mcf.

(in 1980 dollars). This is in contrast to \$3.84 per mcf 2/ with the latter, which with the blending of old gas lowers the price of blended gas flowing in the partners system by roughly one-third in this example. The weighted average price of gas acquired by the ANGTS partners would be \$1.31 higher -- an amount greater than the average cost of prebilling -- if it were not for the roll-in of controlled gas under these assumptions.

C. The Market Clearing Mechanism for Natural Gas

One of the best examples of the energy market at work is the market for Prudhoe Bay crude oil and the experience with it since the opening of the Trans Alaskan Oil Pipeline. Economic theory suggests that energy markets -- when they work well, unimpeded by regulation, the natural monopoly nature of the utility industy, and other obstacles -- take into account such factors as quality and transportation cost differentials in such a way that they are fully reflected in prices. Lower quality crudes sell at lower prices than higher quality oils. Those in remote locations sell for wellhead prices depressed to reflect the higher transport cost involved in getting them to market.

With Alaskan North Slope (ANS) crude, a high pipeline tariff plus tanker transport charges are associated with its delivery to refineries, where it has to compete with many other crudes available to the refiner. Thus, delivered prices for these oils are determined in a competitive marketing process. Because of this competition, ANS crude cannot continue for long to sell on a delivered basis at a higher price than other oils, even though the price

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2/ Based on the weighted average of \$4.80 (90%) and \$9.06 (10%).

reflects higher transport costs. As a consequence, transport costs are effectively absorbed at the wellhead, and the resulting financial netback realized at the wellhead by producers is reduced by the transport differential. This highlights an important economic point. In a market situation, wellhead prices will be reduced to reflect above average transport costs. This phenomenon is well documented with wellhead oil prices, but it appears that gas has circumstances associated with it which tend to insulate it from responding to these more customary forces. The ANGTS discussion to date contains little indication that the matter of wellhead prices reflecting the high tranport cost is being actively considered. Unlike oil producers, who must absorb transport cost differentials, the gas pipelines involved in the ANGTS project appear to be seeking situations which will permit the gas producers to avoid exposure to the market forces oil producers must face. Several sets of economic forces could be operative here, and they will likely be different than those associated with oil. In fact, the utility nature of the natural gas business (a regulated natural monopoly serving consumers who are, to some extent, captive) tends to blunt market forces.

A range of economic alternatives can be delineated which would offer extraordinarily high-priced gas some form of shelter from market forces, but the basic premise which underlies the fact that utilities can, and indeed now do pay very high prices for incremental gas supply is the natural monopoly nature of the utility business. Utilities have long been permitted in large measure to pass on costs without the inhibiting forces of direct competition. Now, with the prospect that natural gas and fuel oil prices will converge in terms of Btu-equivalence, the basis of interfuel competition is beginning to change. To deal with stronger competition as gas prices rise, the pipeline companies who must purchase gas from producers and sell it to end users seek ways to remain competitive with fuel oils, while seemingly avoiding situations in which market forces would tend to depress producer-prices at the wellhead. Utility regulation and the NGPA would lead to the allocation of ANGTS costs across the total sales of the pipelines involved. This would greatly dilute the perceived cost of Prudhoe Bay gas, as viewed by end users who would notice only relatively small increases in their unit gas costs. By lowering the apparent cost of ANGTS gas, the market forces which normally tend to lower wellhead prices because of high transport cost differentials could well be blunted.

D. Inclusion of ANGTS Fixed Costs in Partner Pipelines Cost of Service

If the ANGTS project proceeds, its cost would be added to the basic cost-of-service of the pipelines involved in the partnership. A simplistic illustration of the way in which this might work is to assume that the project as a whole would be completed by a certain date. During the construction period, the project would accrue interest, which would be capitalized. This would be similar to the conventional way in which utilities accrue allowance for funds used during construction (AFUDC). Then the whole project cost would be amortized exactly the same way a mortagage is amortized. In this case there would be a level annual payment consisting of declining amounts of interest and increasing amounts of principal over time. Since utility rates are made in "as spent" or nonimal dollars, the sponsor financing plan centerpoint would result in a \$44.3 billion rate base. Amortization of this over 20 years at a 20% composite (the average cost of debt and equity) rate of return would result in annual charges of about \$9.1 billion in principal and interest.

In 1980, the combined ANGTS partnership had sales of 7.8 tcf. Assuming they can maintain this level and can market an additional .7 tcf of ANGTS gas, the additional burden of the ANGTS' amortization would add an average of about $1.10 to every mcf sold on those systems. This could raise the average fixed cost of serving every customer, adding for example about $130.00 annually to a typical residential gas bill, assuming that all customers would pay the same unit charge.

The ultimate responsibility for actually allocating this extra burden will fall on state public service commissions. There is some chance that fear of lost industrial load (and its deleterious effects on the economics of pipelines and local distribution systems) mights lead to a disproportionate share of this burden falling on residential and commercial consumers. This is particularly true for residential and commercial consumers who cannot switch to cheaper oil fuels (chiefly residual fuels oil). Historical regulatory practice, however, would have this charge passed on from ANGTS partner pipelines to the distribution utility systems they serve in the purchased gas price. This would be reflected in the purchased gas adjustment clause (PGA), which virtually all gas utilities have. The PGA is a regulatory mechanism which allows pipelines to pass on high gas costs. As such, it would appear as higher commodity charges to the local utility and its customers. In most cases, the higher gas costs (including ANGTS supply) would presumably be passed along in the PGA, and be allocated uniformly to all classes of consumer.

It should be noted that the $1.10 per mcf is an average charge against all gas moving in the partners' systems. The true fixed system cost associated with the transport of Alaskan gas here is $13.00 per mcf. 4/ This incremental fixed cost does not include the commodity itself. The purchase of the .7 tcf per year that would be facilitated by the ANGTS waiver package would have to be paid for additionally. Under the NGPA as it stands today, this would be priced at $2.08 per mcf (in October, 1981), the base price of $1.45 per mcf plus inflation. This means that at current price levels, the full marginal or incremental cost of ANGTS would be over $15.00 per mcf, and if Prudhoe Bay gas is deregulated, the price could well be higher.

E. Price Determination -- The Market Mechanism As It Affects Alaskan Gas

The market mechanism for gas has been complicated by years of regulation. Standing between the ultimate purchaser and producer is the regulated utility industry. Apart from wellhead controls, the regulated behavior of the utility pipeline industry stands as a barrier to the sort of corporate performance which is necessary for the gas market to perform the allocation and pricing functions normally expected of the market mechanism (absent governmental regulation).

The operation of natural gas markets has been of little recent concern to policy makers because gas prices have been set more by government fiat than by market forces for more than a quarter of a century. As more gas becomes unregulated under NGPA and a complete deregulation is contemplated, however, market behavior reappears as an important consideration quite relevant to ANGTS economics.

Prudhoe Bay Gas, controlled by the NGPA at $1.45 per mcf plus inflation in perpetuity, would probably escalate to a market rate which is presumably much higher than the controlled price. Market clearing mechanisms are very complex affairs and could interact with the pre-billing provision in adverse and unintended ways.

4/ This figure is obtained by dividing the $9.1 billion amortization project by annaul ANGTS supply, .7 tcf.

There is also a role played by contracts between gas producers and gas transmission companies. The contract which CRS analyzed -- one date March 27, 1979, between Exxon and Pacific Gas and Electric (PG&E) -- contains provisions which could limit the prices paid if gas were deregulated. Section 11.4 of that contract contains language stating that under deregulation the applicable price would be the highest of:

> (i) the average of the two highest prices paid or contracted to be paid by Buyer or any other interstate purchaser(s) of gas in the Prudhoe BAy area (hereinafter caled "Area") under any gas sales contracts in effect in the Area at the time of such redetermination between a producer(s) and an interstate pipeline company purchasing gas for resale; and (ii) the Btu equivalent price of Distillate Fuel Oil (No. 2) per million Btu's less Buyer's transportation costs per million Btu's of Prudhoe Bay gas incurred between the delivery point for gas specified herein and the Milpitas Gas Terminal, California.

F. Natural Gas Market Dynamics

Gas does ultimately compete with fuel oils at the burner tip. The price determination mechanism is heavily dependent upon competition between gas and oil on a delivered basis. Important factors here are the type of oil and the market's distance (i.e, the transportation cost involved) from the gas fields. Gas may compete at the margin with the lowest grade of high-sulfur residual fuel oil. These final transactions make the market clear and determine prices. Not only has residual fuel historically sold for a lower price than crude oil, but its energy content is almost eight percent higher, making it a much better energy value. The same sort of thing is true, to a lesser extent, of high-sulfur residual fules which sell at energy equivalent values much closer to crude.

Beyond these heavy fuel oils, there is middle distillate fuel, a clean-burning oil which is most commonly viewed as the closest substitute to natural gas. Distillate now sells for a significantly higher price than crude, but it has a lower energy content than resid. Whether or not gas competes primarily with distillate or with resid is a key question. High-sulfur residual fuels sell at the equivalent of $4.20 per million Btu's, low-sulfur resid at $7.00 per million Btu. Realistically, it is almost impossible to forecast what these prices might be when ANGTS gas starts to flow, but an assumtion can be made for illustrative purposes that there will be no real dollar escalation from present prices.

What then is likely to be the marginal fuel that gas has to compete with in the future? In tight gas markets, demand (pushed either by economics, the pipeline curtailment process, or regulation) tends to gravitate toward the highest priority consumers -- those with the highest cost alternative fuels (distillate, for example). In times of slack energy markets, residual fuels are the swing fuels because most industrial consumers have the ability to switch among fuels quickly in order to take advantage of changing economics. The ability of these industrial fuel users to rapidly make and implement choices between fuels, makes energy markets function and causes fuel prices to be determined. Fuel markets can operate with leads and lags, or experience regulatory interference, but these economic forces will largely determine gas prices in the long run.

There is another key variable in the set of equations determining gas prices. This is the fact that oil is shipped and distributed rather cheaply relative to the transport costs of gas, and oil and gas compete with each other on a delivered basis. If oil and gas were comparably priced at a point of sale distant from the nearest gas field, the wellhead price of that gas would have to reflect the high transport gas incurred in getting that gas to market, if its delivered price is to be comparable to that of competitive fuels. In order to compete with heavier oil fuels, it is possible that the gas price in this example could be well below the crude oil equivalent for two reasons; the gas transport costs and the fact that it is competing with resid, which typically sells below the price of crude.

At the moment, these are characteristics of current markets wherein there are ample supplies of both resid and gas. A tightening gas supply, however, could result in increased gas prices in terms of diminished interruptible and off-system sales. This would drive industrial users back to their alternative fuel — resid. Users remaining on gas would be those whose alternative fuel is distillate and they would presumably be willing to pay up to distillate equivalent prices. This would tend to set natural gas wellhead prices at the distillate level less pipeline and local utility tariffs.

All this points toward a market which, absent wellhead regulation and despite natural monopoly utility economic behavior, is similar in function to that of Alaskan crude oil. In that market, gas would compete on a delivered basis with other fuels (and perhaps gas sold by other pipeline systems). Its price could well be determined by those end markets, at least in theory. Wellhead prices should, at least theoretically, consist of this market price less the pipeline utility tariffs associated with the delivery of the gas.

To a great extent, gas utilities are insulated from market forces because they supply certain classes of at least temporarily captive customers. The residential sector is a good example, and it accounts for 40 percent of utility sales. Also, there are commercial users and some industrial consumers for whom gas is an essential fuel for which no practical substitute exists. But about 50% of gas utility sales are to industrial consumers. These sales are to a great extent price sensitive, inasmuch as a large portion of this user class can switch with relative ease to oil fuels. In other words, these sales more or less compete with oil directly. These consumers can switch back and forth between fuels, and they constitute the marginal gas distribution system loan which would possess considerable leverage in ultimately determining unregulated wellhead prices.

Discrepancies in the rate schedules of utilities tend to hold price sensitive customers, while higher prices are charged to consumers with less elastic demand. While this sort of price discrimination is typically frowned upon by state and federal regulatory bodies, in practive there are exceptions to the general regulatory bias against price discrimination among classes of customers which is not justified by the cost of service. Included among these exceptions are interruptible sales to balance load on winter-peaking systems, and off-systems sales of gas (often at prices below marginal supply cost). The uncertain reaction of regulatory bodies to future load losses, the deterioration in utility economics associated with the operation of underutilized pipeline systems, and the possible behavior of the FERC and State utility regulatory bodies in the face of escalating wellhead prices are matters in need of exploration. Whether or not residential and commercial users are to be burdened with utility service costs which had previously been attributed to and borne by the price-sensitive industrial class of consumers may raise equity questions for the future as wellhead gas prices approach some form of parity with oil.

There are other possible outcomes which flow from the economic conditions described here. If gas is deregulated or otherwise rises to the equivalent price of oil at the wellhead (because increased amounts of high-priced gas under the NGPA is blended into the mix of flowing gas over time), pipelines, especially those burdened with ANGTS costs rolled into their cost of service, will find it difficult to sell their gas and recoup their full cost of service because of competition from oil. These pipelines would either earn losses or be forced to negotiate lower commodity prices with producers.

The second pricing alternative in the previously noted Exxon-PG&E contract is a good example of such a situation. In it, PG&E agreed to pay the equivalent of distillate prices for gas delivered to California, less transport costs to their terminal in California from the processing plant in Alaska. Although this appears to be a deal well construed on economic grounds, there could be some problems in marketing this gas to price-sensitive customers. The following are two possibilities:

(i) The gas distributed through PG&E's system will incur tariffed charges set by the state utility commission and then be sold in competition with other fuels at a price equal to the wholesale distillate price plus the PG&E tariff. Clearly this is likely to result in burner-tip prices above that of distillate.

(ii) Low-sulfure resid can be used by many PG&E industrial customers. Under the proposed pricing plan, ANGTS gas may not be competitive here absent the roll-in of cheaper gas or unless some form of rate structure favoring this class of user under PG&E tariffs approved by the state PUC.

G. Potential Concerns Associated with Inclusion of ANGTS Costs in Partners Cost of Service

Contractual relationships like the Exxon-PG&E deal described above would circumvent some of the presumably unintended and unanticipated side effects of the possible interaction of utility business practices and energy economics in an environment without wellhead price regulation. Nevertheless, there is a possibility that the combined inclusion of the ANGTS cost in the partners' rate base and the tariffed cost of service could result in very high well-head prices at Prudhoe Bay under decontrol. Note also the first pricing clause of the Exxon-PG&E contract, which specifies that the highest field prices paid by others would prevail. Some potential for concern exists here. Other purchasers with the ANGTS costs embedded in their ratebases will not, because of the relative marginal cost of incremental gas supply, discriminate between Lower-48 supplies and those from Prudhoe Bay. This is the scenario of concern.

Pipelines which are not ANGTS partners and which are not burdened with ANGTS amortization rolled into the tariffed rates charged to their customers will be able to bid for Lower-48 state gas and pay a higher price for several reasons:

--Because non-ANGTS pipelines would probably have a lower cost of service, they could pay higher wellhead prices than the ANGTS partners and still deliver gas for less, since they would not be burdened by the rolled-in cost of the project.

--The location of energy intensive industry -- as well as generally high rate of population and economic growth -- has focused on the South-western United States. Much of the marginal demand for gas, in all likelihood, could be located near South-western United States. Much of the marginal demand for gas, in all likelihood, could be located near South-western gasfields. The transport costs associated with this demand would be low, so a high wellhead price can be paid without adversely effecting those pipelines competitive position vis-a-vis oil fuels.

This could lead to a situation in which the ANGTS partners who will only receive ten percent of their supplies for Prudhoe Bay, are also bidding for Lower-48 gas against other pipelines which are not supporting the high cost of the ANGTS. The cost of service and near location of the other pipelines will determine their ability to bid and could allow them to set a higher price for gas than the ANGTS partners might otherwise be willing to pay. This could place the ANGTS partners in the position of having to pay a market clearing price for Lower-48 gas that is determined by other pipeline bidders who have lower costs of service. If they are willing to bid for this gas -- as they must if they intend to supply markets now supplied -- they will also probably be willing to bid against each other in Alaska on the same price basis as they bid against other pipelines in the Lower-48 states.

H. Implications of Decontrol for Prudhoe Bay Wellhead Prices and ANGTS Economics

The general economic environment created by the roll-in of ANGTS amortization with the cost of service of the partner pipelines, coupled with some portion of the cushion effect provided by gas contracts, might well result in a situation where Prudhoe Bay wellhead prices -- assuming that this gas were decontrolled -- could rise to considerably higher levels than they otherwise might. This would be due to the fact that both factors may tend to blunt market forces which could otherwise act to depress wellhead prices, reflecting the fact that the commodities net value is reduced because of the costly transportation involved in its delivery to the Lower-48 state markets.

Perhaps the most significant factor involved there is the over 90% reduction in the perceived cost of trasportation -- using the example cited above. This is based on the roll-in of ANGTS costs with the overall cost of service of the partner pipelines Lower-48 state systems. Significant dilution occurs here. Gas whose unit transport cost was estimated to be on the order of \$13.00 per mcf, ends up being sold to consumers at a diluted transport cost of about \$1.10. If this gas were sold at a price reflecting its full incremental transport cost (\$13.00), it would lose its competitive advantage vis-a-vis other gas, and other fuels which would leave little room for high wellhead prices. In other words, the high net cost of the ANGTS facilities amortization would result in a lower wellhead price because -- if the full ANGTS cost were charged consumers -- it would place Prudhoe Bay in such a tight competative situation that there would be little alternative b[illegible] s wellhead price to be depressed to a level reflective of the lower 48 burner tip price for clean fuels, less the high transportation cost. This is in fact exactly what has happened to North Slope crude oil. High pipeline tariff and tanker rates associated with its delivery to refineries have resulted in netback prices at the wellhead which fully reflect the depressing effect of high shipping costs. North Slope crude therefore sells for much lower prices at the wellhead than comparable crudes in the Lower-48.

With the ANGTS system costs rolled-in with the rest of the partner pipelines' service costs, a much lower transportation cost will be perceived by consumers at the burner tip. This leaves a great deal of margin for the partner pipelines -- in bidding against one another for Alaskan supplies -- to pay higher wellhead prices and still be able to deliver a product at what consumers see as a competitive price. In fact, the roll-in provides an extra \$12.00/mcf margin or latitude within which pipelines can determine prices. In competing with one another, pipelines will clearly be able to pay producers higher prices if they can charge consumers \$1.10/mcf for transport rather than \$13.00. Quantifying the extent to which higher prices will be due to the averaging out of the ANGTS costs is difficult, but it is obvious that wide latitude to pay higher prices is provided by the effective hiding of the true ANGTS cost. The ANGTS cost will be concealed among the other cost of service associated with 90 percent of the partners' sales from Lower-48 supplies on the rest of their pipelines' systems.

One possibility that could be an important factor in determining Prudhoe Bay wellhead prices is the Lower-48 market clearing price. As noted above, with a lion's share of the partners' supply coming from Lower-48 sources and with ANGTS amortization imbedded in their cost of service, they may well be price-indifferent between Lower-48 supply and Alaskan supply. If this were to be the case, the Lower-48 market clearing price -- determined by competition between pipelines whose overall cost of service is lower than the ANGTS partners because they do not share the project's burden or because their sales are to consumers less distant from gas fields -- could apply in North Slope gas fields as well. Because of the lower cost of service experienced by participants in the Lower-48 marketplace, they could set gas prices much higher than the ANGTS partners would pay, absent having to bid against other pipelines for supply. This could put the ANGTS partners in an adverse competitive position, resulting in their not only having high cost of service, but having to pay wellhead prices determined by competitors who have low cost of service and who can therefore pay high wellhead prices. In situations where ANGTS partners must compete with these other pipelines, they may well suffer reduced market shares. This may also be true in situations where gas must compete with residual fuel. Accompanying reduced market shares are the unfavorable economics of pipeline systems operating at less than full capacity, which would tend to raise unit operating costs. This, in turn, would place upward pressure on delivered gas prices and could lead to increasing prices and declining sales.

Finally, there is the matter of old gas which might remain under contract in the late 1980s, even under gas deregulation. Any low-priced gas on the partners' systems will enable them to lower their effective or average purchased gas cost and could enable ANGTS partners to pay higher wellhead prices. Again, incentives to escalate Prudhoe Bay wellhead prices (absent controls) could be created. The process of averaging in high and low cost items plays a role inhibiting the operating of market forces, which in this case would tend to moderate producer prices. Any low-priced gas flowing under old prices institutionalized either by contract of law would tend to work in this direction. Whatever low priced gas might be flowing at the time the ANGTS becomes operational could facilitate higher Prudhoe Bay prices for producers.

VI. THE POTENTIAL CONSEQUENCES OF NOT HAVING A PIPELINE

A. Introduction

U.S. relations with Canada are extremely complex and interwoven. Each country is the other's largest trading partner and each attracts the largest share of the other's foreign investment. However, two basic differences between the two countries dominate their relationship. First, the U.S. is ten times the size of Canada in terms of population and in Gross National Product (GNP). Second, Canada has historically struggled, often through government programs, to maintain its economic independence and national identity despite the influence of its neighbor.

The difference in size of the two economies has meant that Canadian investment in the U.S. has only scattered, local impact. On the other hand, the American economic presence in Canada has been a major factor in the Canadian economy and politics. It is also a major factor in any Canadian view of its relationship with the U.S.

The roles of Federal Government are different in each country. Since World War II, the Canadian economy has grown rapidly with the inflow of American capital. Aware of this, the Canadians for some years have sought to define a national economic policy, to establish rules and guidelines for investors, and to employ government assistance to direct the economy. In international trade, the Canadians have encouraged trade diversification to reduce Canada's economic dependence on the United States. On the other

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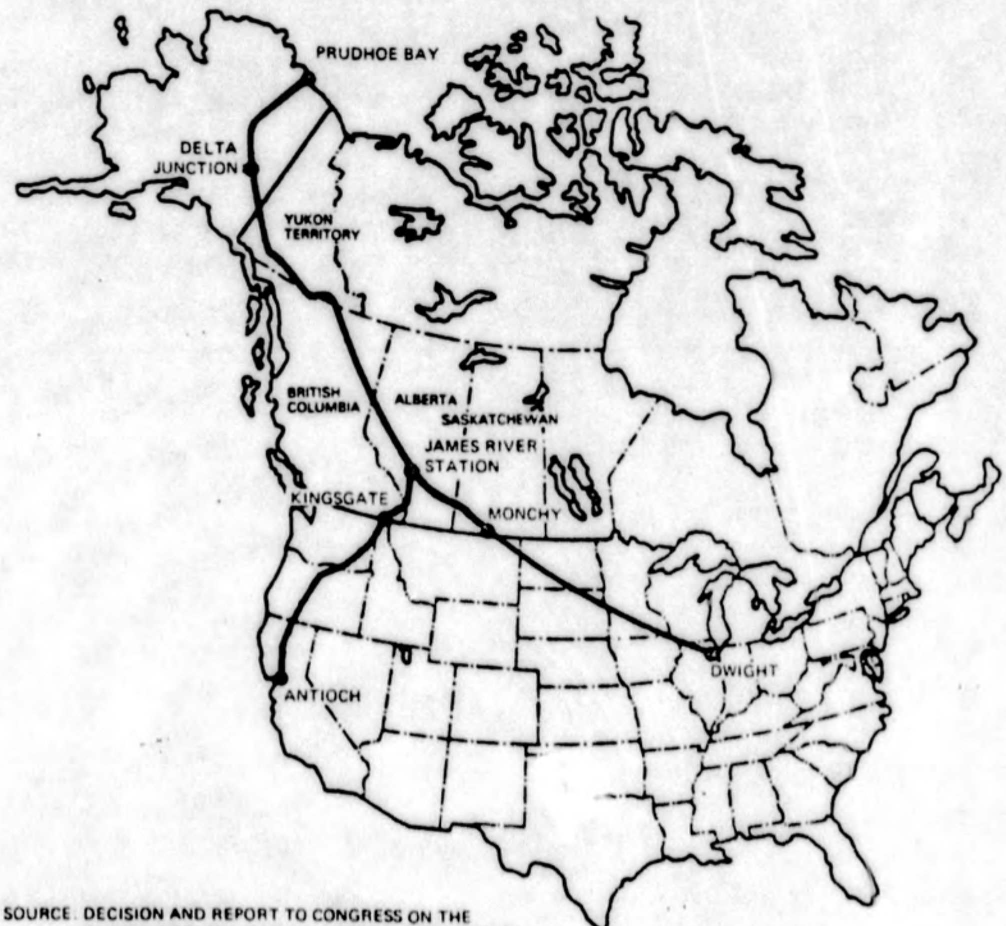
*/ Prepared by Gary Pagliano, Analyst in Energy Policy, Environment and Natural Resources Policy Division, Congressional Research Service.

Map I



SOURCE: DECISION AND REPORT TO CONGRESS ON THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM hand, in the United States market forces have generally determined the flow of money and trade in industrial goods within tariff and other regulatory limits. Government export restrictions or disincentives are more a characteristic of the United States, while Canada offers important incentive for manufactured goods exports and maintains few disincentives beyond those limiting exports of energy. 1/

With the re-election of Prime Minister Trudeau, Canada's economy is now more subject to governmental direction than in the recent past. A prime example of this is the new Federal policy to "Canadianize" foreign-owned investments in the energy industry. The main objective of the policy is to have at least 50 percent of Canada's oil and gas industry owned by indigenous Canadian companies rather than by subsidiaries of U.S. companies, which currently own about 70 percent of the Canadian oil and gas industry.

Successful but bitterly contested Canadian takeovers of U.S. subsidiary companies have prompted resentment in both counties. The United States objects because it is taking the brunt of a policy the Canadians claim is pro-Canadian but is widely interpreted as anti-American. Canada, for its part, is upset by the apparent misunderstanding of its policy in the United States. Tensions have recently heightened with U.S. talk of limiting Canadian ownership in the United States.

1/ Armstrong, Willis. U.S. Policy Towards Canada: The Neighbors We Cannot Take for Granted. The Atlantic Council of the United States July 1981. p. 16

While "Canadianization" is perhaps the most publicized problem between the United States and Canada, others are as volatile and include the following: (1) charges on both sides of inequities in the Automotive Agreement; (2) Canadian charges that its acid-rain problem is caused mainly by the United States and (3) U.S. resentment of Canada's natural gas export policy of controlling the quantity of exports and pegging its export price, in large part, to international oil prices. 2/

Canada and ANGTS

The ANGTS has remained a troubled but viable project during the evolution of these problems. In 1975, the ANGTS selection process started with three main contenders -- a U.S. liquefied natural gas (LNG) proposal and two overland, U.S.-Canadian Pipeline proposals. Two years later President Carter and Prime Minister Trudeau jointly announced they had selected the Alcan highway route for transporting Alaska natural gas to the Lower-48 States. 3/ The ANGTS would be built in two phases because of project financing reasons. Phase I called for the planned pipeline system south of James River Station to be built by October 1982 and to begin delivering Albertan natural gas to the Lower 48, thereby generating revenues to help finance the more costly and more difficult northern section.

2/ For more detail on these issues see the following CRS issue briefs: IB 80022, Acid Precipitation: A Serious and Growing Environmental Problem; and IB 80095, Canadian-U.S. Relations.

3/ For more detail on the selection process see CRS issue brief 75083, Alaskan Natural Gas: When and How.

Since work began on Phase I of the "pre-build segment" of the ANGTS, Canada has sought repeated assurances from the U.S. that the rest of the pipeline would be completed. The Carter and Reagan Administrations as well as the U.S Congress, have expressed support for the ANGTS if the project could be financed privately.

Canada's main worry is that the Alaskan segment will not be built and that Albertan natural gas will become the sole source of supply for a pipeline delivering gas to the U.S. As an open ended long-term arrangement, this would most likely be unacceptable to the Canadian Federal government, which began in the 1970's to closely control the amount of gas available for export. Federal control resulted from Canadian realization that it would otherwise become a net oil importer and would become vulnerable to supply disruptions such as those resulting from the 1974 Arab Embargo. Natural gas is seen by the Federal Government as a substitute for oil in the residential and industrial sectors, thus relieving pressure for more oil imports. Rightly or wrongly, natural gas in Canada is seen as a resource for primarily domestic use by the Federal Government and to a certain extent by many Canadian citizens.

On the other hand, there are Canadians particularly in the gas-producing provinces of Alberta, Saskatchewan, and British Columbia who disagree not only with the tight Federal controls on gas exports, but also with federal price controls on domestic gas sales and higher Federal taxes on gas export sales. The producing provinces favor a reduced Federal presence in the Canadian domestic and export gas market for the following reasons: (1) gas exports could increase without any appreciable drain on Canada's gas resource base, which the producing provinces and others believe is significantly understated by the Federal Government because of national security reasons; (2) the producing provinces are unhappy with Federal price controls on domestic gas to encourage greater gas usage because it means lower provincial-producer revenues and a lower sales volume due to a slower-than-expected increase in gas demand; and (3) producing provinces believe the gas industry could provide a greater stimulus to Canada's ailing economy and could improve Canada's balance of payments through greater investment, drilling activity, production and gas exports. As a result, the "producer perspective" could view an incomplete ANGTS project as a real market opportunity to expand gas sales in the United States.

While the "producer perspective" is ever present, it is the "Federal perspective" that would dominate any official Canadian reactions, at least in the short term, to an incomplete ANGTS. The following factors would shape the reaction of the Canadian Federal government. First, the Trudeau Administration has taken some political risk in approving the pre-build segment which was based in part on U.S. Government assurances. Second, the major Canadian segment of the ANGTS lying north of James River the construction of which is in question) would inject $11 billion (escalated 1987 dollars) into the Canadian economy. 4/ This sum would amount to at least one percent of Canada's GNP during the four years of its construction and would result in Provincial and Federal Government taxes averaging $50-100 million annually on the pipeline.

4/ Office of the Federal Inspector's Cost-of-Service Model for ANGTS, October 22, 1981, pg. 16.

Other factors include Canadian plans to build a branch pipeline (the Dempster Highway Lateral) from the planned ANGTS Canadian segment to the Mackenzie Delta where there are an estimated 6-8 trillion cubic feet (tcf) in natural gas reserves that could be transported to Canadian markets. Recently, however, administrator of Canada's Northern Pipeline Agency said that the Dempster Lateral is not practical because the ANGTS problably would not have enough spare capacity to handle the volumes of gas being discovered in both the Mackenzie Delta and the Beaufort Sea. 5/ In addition, if just the pre-build project were completed (south of James River Station), Canada could be saddled with excess pipeline capacity in five to seven years under current conditions. This is because the pre-build pipeline, which has a capacity of 2 billion cubic feet per day (bcf/d), would use all of the new gas (3.75 tcf) that the Canadian National Energy Board (NEB) has determined could be exported in the forseeable future. Although the size of Canada's gas reserve base could permit greater exports and Canadians have discussed exporting liquified natural gas from British Columbia to Japan, the NEB (which is the energy arm of the Canadian Government), could constrain any further new gas exports from Canada.

It is thus apparent that Canada would suffer negative consequences from the ANGTS not being finished. There would be some political repercussions particularly from those who believe the U.S. is draining Canada of its major abundant energy resource. A lot of time and money

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5/ Platt's Oilgram News. October 29, 1981. P. 2.

has already been invested in the ANGTS by private Canadian gas pipeline companies, engineering firms and government agencies. In addition, Canada's economy would suffer from the loss of potential jobs, capital investment opportunity, revenues tax, etc., that would have been generated by the project. Conversely, Alberta's Premier Lougheed recently said that completing the ANGTS could have a "negative" effect on Alberta's economy and Alberta is now "neutral" toward the project. 6/

There are several facets of the decision on the ANGTS which are likely to affect U.S.-Canadian relations. First, there is the timeframe during which the decision is made. If the U.S. Congress does not approve the current waiver package, the project would probably be abandoned because of financing difficulties. A quick decision (even a positive one), could be just as damaging to U.S.-Canadian relations if financing cannot be arranged with the waivers. A longer timeframe could provide opportunties to improve country relations in general and to on address the consequences of the ANGTS, whether it is completed or not.

Second, the U.S. Government handling of the ANGTS decision is very important. Even though the project has been touted a private sector project, the U.S. Government has provided official assurances to Canada that the ANGTS waivers would be sought. If the waiver package fails, the Canadian Government would surely question the level of U.S. Government support.

6/ Platt's Oilgram News. October 29, 1981. P. 1.

And third, some alternatives to the ANGTS could involve Canadian gas because of its proximity to Alaskan gas resources, and the potential economies of scale of joint transportation facilities. Frequent and explicit communication between the two countries is essential to any future joint venture. The Canadians should appreciate, however, that any action in the United States on the ANGTS has to be viewed with the same understanding that they are demanding of Americans concerning the Canadian National Energy Plan.

VII. NET NATIONAL ECONOMIC BENEFIT: IS THERE A LOSS?*

A. Introduction

Net National Economic Benefit (NNEB) is the term used to describe quantitative value of the ANGTS to the Nation after allowances have been made for project costs. 1/ The higher the NNEB, the more desirable the project. The following is a summary of the NNEB studies done on ANGTS:

TABLE III

NNEB Studies on ANGTS (billions of 1980 dollars)

Study	Base Case Costs	Base Case Benefits	NNEB
1. President's Decision 2/ and Report to Congress (Sept. 1977)	$10	$20	$10
2. ICF Inc. 3/ (May 1979)	$20	$36	$16
3. Resource Planning 4/ Associates (Sept. 1981)	$36	$68	$32

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*Prepared by Gary Pagliano, Analyst in Energy Policy, Environment and Natural Resources Policy Division, Congressional Research Service.

1/ NNEB is more precisely defined as the present value of the ANGTS gas delivered value minus production costs and transportation costs (including the payment of taxes to the Canadian government).

2/ President's Decision and Report to the Congress on the Alaska Natural Gas Transportation System. White House Task Force. September 1977.

3/ ICF Inc. "A Review of Alaska Natural Gas Transportation Issues", Study done for FERC, May 1979.

4/ Resources Planning Associates. "Net Economic Benefits of the Alaska Natural Gas Transportation System." Study done for Northwest Pipeline Co., lead company for the ANGTS project. July 1981.

Certain key assumptions were essential in the quantitication of the NNEB in these studies. These assumptions are: (1) the discount rate used to compute NNEB, (2) the interest rate associated with the ANGTS debt financing package, (3) project cost overruns, (4) the project life of the ANGTS and potential changes of gas volumes going through the pipeline, and (5) the future behavior of world oil prices. The analysis will show that a significant change in any one of these assumptions can significantly alter the NNEB estimate for the entire project.

It should be pointed out, however, that some benefits associated with ANGTS are difficult to quantify. The most important is the national security benefit of the ANGTS to the United States. Instability in the Middle East has placed a premium on secure supplies of oil and gas, but calculating the most "beneficial" size of such supplies really depends to a significant extent on the imprecise task of calculating the degree of instability in the future.

B. Discount rate

In both the private and public sectors, investment alternatives are evaluated in terms of expected returns over time. The present-value method, which was used to calculate the NNEB, for the ANGTS, is normally used to discount a project's future stream of costs and benefits to the present. The value of net benefits can be quite sensitive to the choice of a discount rate. If the discount rate is 10 percent, the present value of a dollar earned one year from now is 91 cents ($1/(1.10); if the discount rate is 20 percent, the present value of a dollar earned one year from now is only 83 cents ($1/1.20). These differences widen as receipts occur further out into the future. For example, changing the discount rate in the ICF study's base case from 6 percent to 10 percent (excluding inflation and before taxes) reduces the ANGTS' NNEB by 44 percent to $9 billion (from $16 billion). In the Resource Planning Associates study, the NNEB decreases by 58 percent to $13 billion (from $32 billion).

Many factors influence the choice of a discount rate. The rate used depends on whether or not costs and benefits are expressed in nominal dollars (for which a nominal discount rate is used) or in constant dollars (for which a real discount rate or a nominal rate less anticipated inflation is used). The basis for choosing a discount rate also depends on whether or not a pretax return (the opportunity cost of investment) or an after-tax return (the private rate of time preference) is used. For public projects, the choice of these two concepts may depend for public projects, on whether resources are to be drawn from investment or consumption. In addition, the amount of a subjective risk premium associated with a project and the presence of positive or negative externalities not accounted for in the stream of costs and benefits influence the choice of a discount rate.

Although market interest rates can be observed, the volatility of interest rates over the short term, the difficulties of measuring taxes and estimating anticipated inflation and problems with measuring returns to equity, along with the factors described above result in a wide range of discount rates which might be justified for a cost-benefit analysis. Thus any estimates from a cost-benefit study should be viewed with caution.

What is the proper discount rate for the ANGTS? There are two primary and distinct concepts of discount rate -- a private sector discount rate and a social discount rate. A private sector discount rate is the cost of capital to a particular company and is determined by taking a weighted average of the company's cost of debt and cost of equity, coupled with the company's minimum desired rate of return. Each company uses a different discount rate based on its own financial condition and the prevailing financial market condition and the project's risk as perceived by the market. For the ANGTS, a defensible estimate of the private discount rate, reflecting a percepti›n of substantial risk, is 12 percent, before taxes and after subtracting the inflation factor. 5/

The other concept is the social discount which is used to evaluate project value to the Nation as a whole. This concept may be applied, for example, when the project uses the Nation's natural resources or is federally financed. One accepted definition is that the social discount rate should be the opportunity cost to society in undertaking a particular project. Some experts dispute the degree of numerical difference between social and private discount rates, but most argue that the social discount rate should be lower. In 1972, the Office of Management and Budget promulgated a discount rate of 10 percent (before taxes and after inflation) for Federally sponsored investment projects.

The appropriate ANGTS discount rate depends on the choice of either a private or social perspective when evaluating the ANGTS. Because the project primarily involves the private sector, however, the appropriate discount rate would appear to be closer to the private discount rate (which may be about 12 percent if high risk is inferred...see footnote 5). The effect is to reduce the NNEB associated with the ANGTS.

5/ The estimate is based on borrowing cost of 20 percent, 75 percent debt finance, a 35-percent return on equity, the newly enacted tax law and a 7-percent inflation rate. This calculation reflects an extremely high degree of risk associated with the project. If a return of 20 percent on equity is assumed (typical of that earned by oil companies), the discount rate would be about 8 percent.

C. Interest Rates and Project Cost

One factor influencing the discount rate, or the cost of capital for ANGTS, will be the outlook for real interest rates (i.e., after deducting inflation rates) in the capital markets. The real interest rate level is important because 75 percent of the ANGTS capital cost would be financed through debt instruments (as compared with about 41 percent for the rest of the gas pipeline industry). Higher interests rates mean higher project costs and as a result lower NNEB as shown in Chart I.

The Congressional Research Service (CRS) used the Office of the Federal Inspector's (OFI) Cost-of-Service Model to test project cost sensitivity to interest rates. The OFI's base case uses an interest rate of 11 percent and an inflation rate of 8 percent in projecting the ANGTS cost of $44 billion or $22 billion in 1980 dollars. The real interest rate is 3 percent (11-8 percent). If real interest rates in the future were to vary, Chart I shows the possible effects on project costs. The range of effects is between -$.5 and +$.8 billion. The effect on the project sponsors, however, could be reduced by 50 percent because of taxes.

Higher interest rates would also accentuate the effect of any project cost-overruns or delays in completion. The cost-overrun potential is tied mainly to the Alaskan segment of the project; unlike Alaskan costs, Lower-48 gas pipelines typically are constructed at a cost within 5 percent of the initial estimate. 6/ The perceived Alaska gas segment cost-overrun

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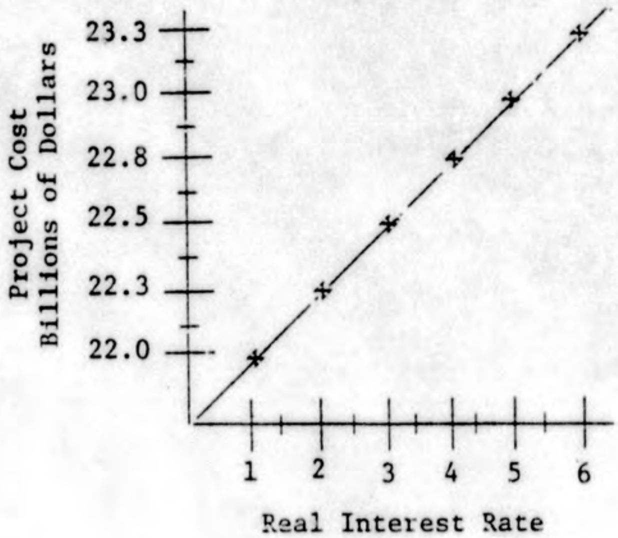
6/ ICF Study, op. cit., p. II-18.

CHART I

The Sensitivity of Project Costs to Real Interest Rates
(1980 Dollars)



Pts.

Int. Rates	Proj. Cost
1	22.0
2	22.3
3	22.5
4	22.8
5	23.0
6	23.3

potential derives from the experience of constructing the Trans Alaska Pipeline System (TAPS). Compared with an original cost estimate of $1.6 billion, the capital cost of the TAPS ultimately reached $7.7 billion, an increase of 380 percent. 7/ The Federal Energy Regulatory Commission (FERC) currently estimates that the Alaskan gas segment would cost $6.7-$8.1 billion (1980 dollars), but considerable uncertainty exists toward the estimate because of the TAPS experience. This uncertainty is one of the main reasons for the inclusion of the gas producers into the ANGTS project financing and for the pre-billing provision in the waiver package which requires consumers to share some of the risk. One factor which could partially offset the

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7/ Mead, Walter J., Transporting Natural Gas From the Artic American Enterprise Institute, 1977. pg. 88.

project's potential cost-overruns would be the discovery of more gas in Alaska which would extend the useful life of the pipeline.

D. Prospects for Finding More Alaskan Gas 8/

Most analyses of the ANGTS use an operating period for the pipeline of 20-25 years when, in fact, a more typical useful life of a pipeline is 40-50 years. The longer the pipeline operates at capacity the greater the NNEB; the ICF study calculates the NNEB could increase substantially if the pipeline operated for 50 years (depending on the discount rate). 9/

Is there enough of a future gas supply to support such a long period operation? The current knowledge of Alaskan energy resources is insufficient to provide an adequate answer. Proven gas reserves at the end of 1979 were estimated at 31.9 trillion cubic feet (tcf). Of this amount 5.2 tcf is in fields not associated with Prudhoe Bay oil, but located in the Cook Inlet region. The reserve base of 5.2 tcf supports the 50 billion cubic feet (bcf) annual export level to Japan. In the future, additional production from these reserves is expected to be sent to California. The remaining 26.7 tcf of gas reserves are in the Prudhoe Bay oil field.

8/ Most of this section is a summary of a detailed analysis of Alaska's Natural Gas Resources in Appendix II, By Joseph P. Riva, Specialist in Earth Sciences, Science Policy Division, Congressional Research Service.

9/ ICF Study, op. cit., pp. 11-16.

There are other prospects for natural gas sources in Alaska. The U. S. Geological Survey recently updated for 1980 the undiscovered recoverable natural gas resources of Alaska as follows (in trillion of cubic feet): 10/

	95% probability	5% probability	statistical mean
Onshore Regions	19.8	62.3	36.6
Offshore Regions	33.3	109.6	64.6
Total			101.2

The Potential Gas Committee (an industry, government, and academic group of geologists and engineers based at the Colorado School of Mines) also updated for 1980 their previous estimates on the gas resource potential of Alaska as follows (in trillions of cubic feet): 11/

	Probable	Possible (Fairly Likely)	Speculative
Onshore	6	16	28
Offshore	2	13	80
Total	8	29	108

10/ Dolton, G. L., et al. Estimates of Undiscovered recoverable natural gas resources of Alaska.

11/ Potential Supply of Natural Gas in the United States. Potential Gas Committee and Potential Gas Agency, Colorado School of Mines, Golden, Colorado, May 1981. p. 22.

The Potential Gas Committee is less optimistic in regard to Alaskan gas potential than is the U.S. Geological Survey. The 1980 Potential Gas Committee estimates for Alaska are about 30 percent lower than their 1978 estimates, while the Geological Survey's 1980 estimates are somewhat higher than their previous estimates, which were made in 1975.

Even though Alaska is still a frontier area, recent seismic surveys and exploration drilling have demonstrated that areas earlier thought to be highly promising may yield much less oil and gas than hoped. For example, negative exploratory results in portions of the Arctic basin, the Gulf of Alaska, Lower Cook Inlet, and in the Kodiak area have resulted in reductions of estimates of potential gas resources for these regions. 12/

There have been a number of wildcat wells drilled in the National Petroleum Reserve on the North Slope without a major discovery, but this area is still considered to have some hydrocarbon potential. Also, large and promising areas such as the Arctic Wildlife Refuge, the Norton Basin, the Chukchi Sea, and the Navarin Basin have not as yet been drilled. These frontier areas could contain substantial gas resources as could portions of such already partially drilled areas as the Arctic and Cook Inlet basins. 13/

It is interesting to note that, contrary to the Geological Survey, the Potential Gas Committee considers onshore Alaska likely to have a greater gas potential than offshore Alaska. In the speculative category, however, their offshore estimate is considerably higher than their onshore

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12/ Gas: What's Underground? The Energy Daily, May 26, 1981, p. 6.

13/ Ibid.

estimate and not much lower than the high offshore estimate of the Geological Survey. This, of course, indicates the uncertainty of offshore resources especially in areas where there has been no drilling.

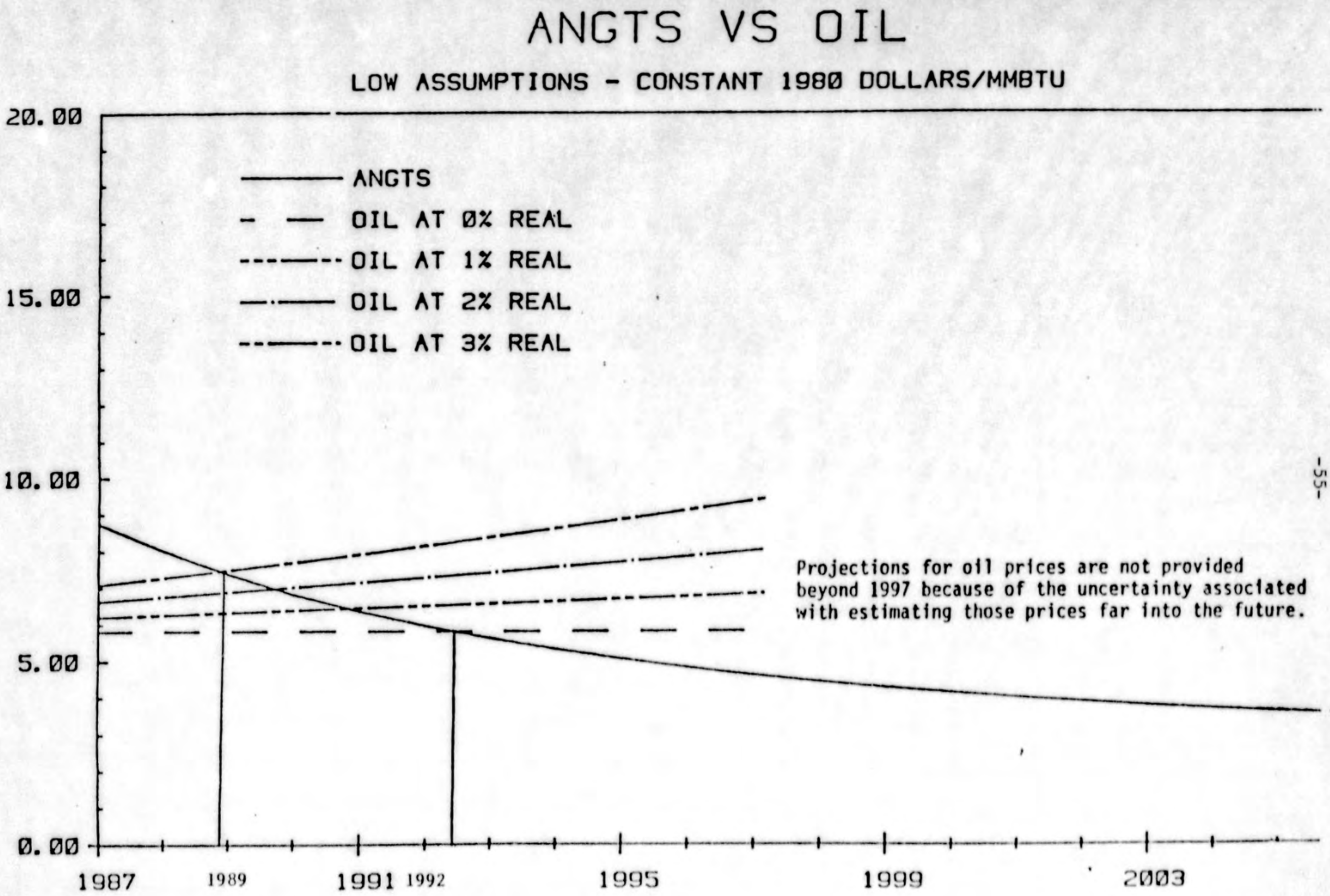
Implications for the ANGTS center on where the potential natural resource might be discovered. The average (about 30 tcf) of the studies' most likely gas potential yields is more than enough (26 tcf) to double the usable life of the pipeline. However, if the new discoveries were in the Navarin Basin, 1,000 miles from Prudhoe Bay and where the weather is extremely severe, there would be minimal benefit to the ANGTS. If the discoveries were in the Arctic Wildlife Refuge, then a relatively short connecting pipeline could make the ANGTS useful for a longer period of time.

E. World Oil Price Behavior

Proponents of the ANGTS have argued that the faster the real world price of oil increases, the sooner gas delivered through the ANGTS becomes more economical (see Chart II), i.e., Alaskan gas becomes cheaper than oil. For example, Alaska gas would be competitive almost three years sooner if the real price of oil increased three percent annually instead of remaining constant in real terms (zero percent annually). The sooner Alaska gas becomes competitive with oil, the two being easily substitutable for each other (particularly in the important industrial sector) the sooner a stable market would develop for the gas. The outlook for stable market would be a major factor in any investor's decision to help finance the ANGTS.

While there are no certainties on the future of the world oil market, perceptions of the future will have significantly changed over the past

CHART II



Source: Office of the Federal Inspector.

year. The new perception is that the tremendous rises in oil prices, particularly over the last 2 1/2 years ($13.00 per barrel to $34.00 per barrel) have contributed to a basic change in the level of demand for oil. Today, the Free World's demand for oil is 11 percent lower than it was in 1979, and the Organization of Petroleum Exporting Countries (OPEC) is producing about 20 million barrels of oil per day (b/d), down from 27.6 million b/d in 1980 and 31.6 million b/d in 1979. Three major consequences have followed from higher oil prices resulting in a decrease in oil demand: (1) reduced growth of the world's economies; (2) energy conservation; and (3) substitution of other energy, such as coal and natural gas for oil.

These three consequences have, in turn, resulted in oil prices decreasing about 10 percent in real terms in 1981, OPEC unification on pricing policy, and Saudi Arabia's Oil Minister assuring the world that oil prices would remain at their present levels for the near future. The effect of stable oil prices, which in fact would mean decreasing prices after accounting for inflation, could enable economies to grow faster, dampen desires to conserve oil and make energy substitutes for oil less attractive. Stable oil prices could also mean an increasing oil demand and perhaps an eventual increase in oil prices. Many believe, however, that current energy conservation and energy substitution trends have permanently reduced present and future world oil demand.

The debate, of course, is over the degree to which oil demand has shifted downward and the effect oil demand will have on future oil prices. Many believe that oil prices will remain stable, decreasing in real terms for the next 3-5 years, and then start slightly increasing for the balance of the century. One study projected the average real price of oil would only increase an average of one to two percent per year for the next 20 years.* Compared to a three percent annual rise, such an oil price trend would mean at least a two-year delay before Alaska gas would be competitive with world oil (see Chart II).

In sum, analysis of several major factors affecting the potential quantitative economic benefits of the ANGTS shows that most of the factors create large uncertainties concerning the project's economic viability. One of these uncertainties is the choice of an appropriate discount rate. If ten percent is used, the NNEB estimates in all three cited studies fall within the range of $9-13 billion. A ten percent discount rate would be reasonable for a normal project during most historical capital market situations, but the ANGTS is not a normal project. If a higher discount rate is assumed, based on extremely high rates of return in light of the great risk involved, the NNEB would be lower and might disappear completely. If somewhat lower discount rates are assumed, the result would be more favorable to the ANGTS.

Stable (increasing at a low rate) world oil prices, while good for the United States in general, would be bad for the ANGTS because they would delay the time when the initially expensive Alaskan gas could be competitive with oil. The prospects for finding more gas in Alaska are good, but location and quantity are factors which would influence potential further utilization of the ANGTS. There is still considerable uncertainty on whether or not those may prove to be greater constraints to production in Alaska than are generally realized.

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*/ Free World Eenergy Outlook. Texaco Finance and Economic Dept. July 1981, 22 pgs.

VIII. THE METHANOL ALTERNATIVE TO THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM *

A. Introduction

Since the Alaska Natural Gas Transportation System (ANGTS) was selected by President Carter in 1977 as the preferred means of transporting gas from the North Slope of Alaska to the Lower 48, there has been concern over that choice. Much of this concern has centered on the financial viability of the pipeline, which would be the most expensive project in history. Without the requested waivers the pipeline cannot be financed, and even with them financing is far from certain. These growing uncertainties combined with a relative surplus of domestic gas have led many to question the original decision. Because of the rapidly growing market for methanol, the conversion of the gas to methanol is an option which is now being examined with renewed interest. Liquefied natural gas (LNG), ammonia, and methanol are liquid forms in which gas can be transported, but only the latter is currently considered a practical alternative to the ANGTS.

The methanol alternative would require the building of approximately 17 barge-mounted methanol plants that would be towed to Prudhoe Bay. Each plant would produce about 24,000 barrels per day and would cost between $375 million and $500 million. 1/ All of the gas would be converted to methanol, none would be stripped as in the ANGTS. The methanol could then be transported to

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*/ Prepared by David Lindahl, Analyst in Energy Policy, Environment and Natural Resources Policy Division, Congressional Research Service.

1/ Sullivan, S. Marsden. Society of Petroleum Engineers of AIME, 54th Annual Fall Technical Conference, Sept. 23-26, 1979, SPE 0296, p. 2.

market by batching it through the Trans Alaska Pipeline, by commingling it with the crude oil in that line, by building a dedicated methanol pipeline alongside the oil line, or by carrying it in tankers directly from Prudhoe Bay. The capital cost of the methanol conversion plants and transportation system would be far less than the cost of the ANGTS. The methanol would be used primarily as an octane booster for gasoline but can also be used as a "neat" fuel for automobiles and powerplants. Its combustion produces very little pollution and could improve air quality if used in place of coal and oil in congested areas.

B. Background

The methanol alternative has been given relatively little attention until recently. During the original debate on North Slope gas transportation in 1977, the methanol alternative was mentioned, but because the methanol would have been in the form of a liquid rather than a pipeline gas, it was not within the jurisdiction of the Federal Power Commission (now the Federal Energy Regulatory Commission) and was not considered by it. A limited discussion of the proposal was included in an environmental impact statement done by the the Interior Department, but it was never given serious consideration by the Administration. Secretary of Transportation Brock Adams, in his letter to President Carter of July 25, 1977, said "There are alternative ways of removing the gas from the North Slope that would not involve the construction of a new pipeline. The most economically attractive of these alternatives is the conversion of the gas to methanol." He added that methanol would become attractive only if the pipeline construction costs were to increase by 50 percent or more. These costs have already increased by more than 300 percent (after adjustment for inflation) and could increase even more before the line is completed. The Secretary foresaw that the high costs and uncertain financing would make rates of return a problem for all of the Alaskan gas transportation projects.

Working against the methanol alternative, now as well as in 1977, are the facts that regulated gas pipelines have a large base over which to spread costs, guaranteed cost passthroughs, and a regulatory system that, with the waiver, could permit customers to be charged for the facility before the system is completed. These are major advantages that tend to skew the economics in favor of the pipeline.

There has also been considerable confusion over the potential cost of methanol made from natural gas on the North Slope. All of the cost estimates start with the same common base of experience with chemical-grade methanol plants in the United States. They diverge on the basis of different assumptions concerning the impact of scale, operating environment, labor reliability, downtime, feedstock costs, financing, choice of transportation modes, and other variables. The current range of cost estimates for delivered methanol is from a low of $.44 per gallon to a high of $1.63.* The lower figure is based on optimistic assumptions of low plant and feedstock costs. The high figure assumes high plant and financing costs.

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*The cost of $.44 per gallon in 1981 dollars (assuming a cost of zero for the gas feedstock) is from the JPL Model (see Chart III); the cost of $1.63 per gallon in 1980 dollars is from the testimony of Richard Rowberg, Office of Technology Assessment, November 9, 1981.

The plant gate cost (1981 dollars) of methanol made in large-scale plants on the North Slope could be on the order of \$.44 to \$.56 per gallon (see Figure 1) based on the economies of scale expected in plants of this size.* These figures reflect a 20 percent rate of return on a \$375 million plant and a 40 percent rate of return on a \$500 million plant; both assume the cost of gas to be \$2.096 per mcf. The current cost than does fuel-grade methanol, which requires about ten percent more processing than does fuel-grade methanol, is between \$.71 and \$.75 per gallon on the Gulf Coast. 2/

The economics of the methanol alternative have improved since 1977 in comparison to the gas line, even without favorable treatment under the Federal regulations. The economics may now favor the methanol alternative with the project cost (1981 dollars) of the capacity to convert the gas stream to methanol being about \$6.9 billion versus \$22 billion for the pipeline, plus the fact that the 408,000 b/d of methanol that would be produced could be used as a substitute for or extender of gasoline and would have a higher market value than natural gas would as a boiler or home-heating fuel. This could result in a higher netback to the producers, larger royalties to the State of Alaska, and greater tax revenue to the Federal Government. The methanol would also back out as much, if not more, foreign oil than would the natural gas.

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* Richard Doff, Wentworth Brothers, private conversation.

2/ Alcohol Week, November 16, 1981, p. 4.

CHART III

THE PLANT GATE COST OF NORTH SLOPE METHANOL*

1981 Dollars

Rate of Return on Equity (%)	$375 Million Plant		$500 Million Plant	
	$/gal.	$/mm Btu's	$/gal.	$/mm Btu's
20	.44	6.60	.47	7.05
30	.47	7.05	.51	7.65
40	.51	7.65	.56	8.40

1987 Dollars

Rate of Return on Equity (%)	$375 Million Plant		$500 Million Plant	
	$/gal.	$/mm Btu's	$/gal.	$/mm Btu's
20	.79	11.84	.83	12.44
30	.84	12.59	.90	13.49
40	.91	13.64	.99	14.84

*Assumes cost of gas feedstock to be $2.096 per mcf and 2.8 million Btu's per barrel; it does not include $.16 per gallon ($2.40/mm Btu's) transportation to Long Beach.

Source: Derived from the JPL Required Revenue Methodology as found in Energy System Economic Analysis (ESEA) Methodology and Leser's Guide, JPL Publication 5 101-102.

Because the market for fuel-grade methanol in 1977 had not developed to the present level and because its massive potential market was not then apparent, most of the bases for cost projection were for low-volume chemical-grade plants with high costs per unit of volume. Proponents of competing systems criticized the methanol alternative as consuming too much (40 to 50 percent) of the gas being transported, although modern methanol plants and delivery systems would have a net resource cost lower than that of the ANGTS when all factors are included. 3/

At the time the two U.S. gas pipeline proposals (Arctic Gas and El Paso) were being considered, a consortium favoring methanol conversion was formed consisting of Westinghouse, Hamilton Brothers Petroleum Co., Mobil Shipping and Transportation Co., Newport News Shipbuilding Co., Kaiser Engineers and Constructors, Wentworth Brothers, Proto Power Management Corp., and the Petroleum Industry Research Foundation. This group, in explaining the proposal to Congress, observed that pipelines transporting North Slope gas would have numerous associated disadvantages in addition to their high costs. These points were apparently not seriously considered by the Federal Government in its assessment of the competing proposals. 4/

Ironically, neither of the original two gas projects were eventually selected to become the ANGTS project. The El Paso LNG proposal failed because

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3/ The Transportation of Alaskan Natural Gas. Joint hearings before the Senate Committee on Interior and Insular Affairs and the Senate Committee on Commerce. February 17, 1976, p. 260.

4/ Op. cit., p. 1367-1369.

of cost and safety problems, and Arctic Gas did not succeed because Canada rejected its route. This opened the way for Northwest Energy (heading a consortium of utilities and gas transmission companies) to enter and win the competition.

If the ANGTS is not built, then the producers of North Slope gas will still need a system to transport it. They (principally Sohio, ARCO, and Exxon) have been reinjecting most of the associated gas (some is used as fuel to maintain reservoir pressures and thereby enhance production). The gas can continue to be reinjected through about 1984, but by then the gas cap in the reservoir will have expanded and the gas-oil ratio will have greatly increased because of the associated gas coning. Some experts have suggested that by 1985, the reservoir may not be able to accept gas reinjection at the current rate. Although continued reinjection may be possible, the physical and economic circumstances indicate that the gas should be produced by that year. About that same time it is likely that the operators will begin their waterflood "sweep" to increase the production of oil from the Prudhoe Bay field to maintain the throughput through the TAPS line, and the oil production gains achieved through reinjection will cease. If oil production continued without a transportation system, the gas could not be legally flared under the Alaska Natural Gas Transportation Act of 1976 (P.L. 94-586) to permit oil production at current rates. Regardless of the means of transportation, therefore, there will be compelling reasons to move the gas even if the ANGTS is not built.

C. Conversion of Natural Gas to Methanol

As indicated earlier, methanol has many desirable attributes as a fuel. It is clean-burning, less toxic than gasoline, can be transported in conventional tankers, and can be used in a wide variety of ways, many of which are higher uses for the original resource than would be possible if the gasoline were left in the form of methane. The Fluor Corp., the prime contractor for the ANGTS, says the following about methanol: 5/

> Methanol has many desirable characteristics as an energy source and transportation fuel. It is easily stored, clean-burning, and can be readily adapted for use in power generation facilities. As a motor fuel, it is finding increased applications in gasohol and as a complete substitute for gasoline.

It is generally conceded even by pipeline proponents that methanol is the only practical form, other than pipeline gas, in which natural gas could be efficiently transported from the North Slope. If the pipeline were not built, then the methanol alternative would become much more attractive because of the undiminished need to remove the gas from the North Slope and the need to provide nonpolluting liquid fuels to the U.S. market. A number of companies (Litton Industries, Swedyards International, Davy Offshore, and Mitsui) have already expressed interest in building the conversion facilities for the North Slope. Others would probably be quickly attracted to a business opportunity of this magnitude in the absence of competition from the pipeline.

5/ Fluor Corp., "Services for the Synthetic Fuels Industry," 1981, p. 8.

Most of the methanol conversion ideas for the North Slope involve the construction of modular methanol production plants that would be prefabricated in industrial areas and then towed to the North Slope. Prefabrication and towing are considered virtually mandatory because of the high cost of construction there combined with the limited season during which they could be built. Because the North Alaskan Coast is ice-free part of the year, towing is not expected to be a problem. In fact, most of the living and working quarters on the North Slope now were taken there on barges.

In most of the proposed designs, each barge would contain a single "train" of three units of 1,000 tons/day. To produce the 3,000 tons/day of methanol would require 100 million cf/day. To convert gas production of 1.7 billion cf/day on the North Slope would require a total of 17 of these trains and would yield 408,000 b/d. The problems of operating these plants in an Arctic environment are unknown at present but are not expected to cause difficulty, according to the sponsors.

One of the major advantages of a system of this type is that it can be done incrementally. Methanol could be made with the arrival of the first train and the others added as they became available. If additional production were desired, more units could be added accordingly. Similarly, once gas production begins to decline and some of the units become surplus, they would have the flexibility to be moved to new fields where production is about to begin. This could be especially important in the Beaufort Sea where ice scour could make the laying of gathering lines (connecting offshore platforms to the mainland) extremely difficult. The large trains would also be useful in distant offshore areas like the Navarin Basin which may be too remote to make connecting lines practical. The gas requirement of a single train is small enough that it could be used to process the gas for even relatively small gas fields on coastal land or offshore.

The flexibility of the methanol trains stands in sharp contrast to the ANGTS (or any gas pipeline). The ANGTS would require completion throughout its length before it could be utilized. When it does come "on stream" it could be underutilized and then gradually reach capacity. When the gas production from Prudhoe Bay declines, the gas line might again be underutilized unless other nearby supplies are discovered. 6/

Methanol is normally produced in a proven and widely used two-part process. The methane is first converted by steam reforming into reactants called "synthesis gas," which is then catalytically synthesized to form methanol. Only one distillation step, the separation of water, is needed to achieve purities of 99.9 percent. 7/ A large amount of fresh water is consumed in the process, but all of the water needed would be made by desalting locally available sea water using waste heat from the plant. By recirculating the gas through the plant nearly all of it, including natural gas liquids (NGL's), can be converted to methanol. This eliminates the need to handle the NGL's (6.5 percent ethane, 3.5 percent propane, 1.7 percent butane, 1.1 percent pentane) separately as would be necessary with the ANGTS. The NGL's would be byproducts of the ANGTS gas conditioning and usable only

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6/ Michael, J. Economides. The Northern Engineer, Summer 1981, p. 7.

7/ Ibid., p. 7.

as fuel on the North Slope or as a feedstock for petrochemicals which would require an additional expenditure of $4 billion for the extraction, pipeline, and fractionation facilities plus another $8-10 billion for the petrochemical complex itself. 8/ With methanol conversion, the NGL's become useful feedstocks that can be used as a premium fuel at its ultimate destination.

Carbon dioxide (CO_2) constitutes 12.6 percent of the gas at Prudhoe Bay, and its presence is an advantage for methanol and a disadvantage for the gas pipeline. It would have to be stripped and vented in the ANGTS because it would prevent the gas from being pipeline quality and would condense in the pipeline (as would some of the NLG's if left in the gas stream). The CO_2, because of its use in secondary and tertiary oil recovery, is worth four times as much as natural gas in the Lower 48 but would be a waste byproduct on the ANGTS. In methanol conversion, the CO_2 is a valuable component of the feedstock and improves the BTU content of the methanol as it is converted to methanol along with the methane. Thus the CO_2 could become an important resource rather than a waste byproduct. It also means that the producers and royalty owners could receive value for a large part of the gas flow that would otherwise be lost.

The most obvious disadvantage of methanol is the energy requirement of the conversion process. Conventional methanol plants, most of which make chemical-grade methanol, consume about 30 to 40 percent of the feedstock as process fuel. This energy penalty is incurred in transforming the gas to the liquid form. In the large fuel-grade plants that would be built for

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8/ Oil and Gas Journal, September 28, 1981, p. 145.

use on the North Slope, however, the plant builders estimate that conversion penalty would be substantially less, probably about 22 percent. This loss has been steadily declining for decades and may go even lower.

This energy requirement is usually given as the major reason for rejecting methanol as an option. Proponents of the methanol alternative maintain, however, that the net resource cost (the amount of the original raw material consumed or lost between the time of its production and its end use) of the methanol alternative is superior to that of the ANGTS. The net resource cost of methanol is the 22 percent lost in conversion plus approximately 4 percent for transportation to a market such as California. The latter component would vary somewhat depending on the mode of transportation (all-tanker or pipeline plus tanker) but could well be less than 4 percent. The net resource cost for methanol therefore, would be about 26 percent, although at least 10 percent (in some applications as much as 25 percent) can be deducted from this because of the improved combustion effic[illegible] relative to energy content associated with the end use of methanol as a [illegible] (either as a substitute for gasoline as an automotive fuel or for distillate as a stationary powerplant fuel). This yields a total net resource cost of about 16 percent, and this could decrease further with advances in technology.

The net resource cost for ANGTS, on the other hand, does not have a single resource cost component as large as the conversion loss associated with methanol, but it has several lesser components that, when combined, are more severe. About 12.6 percent of the gas produced on the North Slope is in the form of CO2 which must be stripped from the gas stream and vented (or reinjected) before it can enter the pipeline. Another 12.8 percent of the gas stream is in the form of NGL's, all of which cannot be carried in either the ANGTS or TAPS. They would either have to be used on the North Slope as fuel or reinjected. 9/ An expensive (estimated $6 billion) conditioning plant would have to be built to remove these gases. The resource cost of operating this plant including the separation of the NGL's from the methane, would probably be about 5 percent. In addition the intense compression that would be needed to force the gas through the line and the refrigeration needed to protect the permafrost and to increase throughput would probably add another 10 percent. This yields a net resource cost of 40.4 percent, not including the energy cost of building the pipeline (which could be much greater than the cost of building the methanol plants).

Each barge-mounted methanol plant with a capacity of 3,000 tons/day could probably be delivered for $375 to 500 million. 10/ Construction time would probably be about two to three years from the time of the contract signing. The plants completed first could begin operation immediately and would be supplement by the others as they became available. Not all of them would have to be completed and in place before operations could begin (in contrast to the ANGTS). If a gas stream the size of the one planned for the ANGTS were converted to methanol, the production of methanol would be approximately 51,000 tons/day (408,000 b/d). According to the JPL model

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9/ It may be possible to blend the heavy NGL's with the crude oil and transport them through the TAPS and to return the light NGL's to the ANGTS, although they would probably have to be removed before entering other gas pipelines.

10/ JPL Model (See Appendix).

(see Appendix), this would require 17 "trains" at a cost of $6.9 billion (1981 dollars). It was estimated that the annual operating and maintenance costs would be about $658 million.

According to the base case for the Cost-of-Service Model prepared by the Office of the Federal Inspector, the first-year price of gas through the ANGTS would be $15.15 (1987 dollars) per million Btu's. As shown in Figure 1, the plant gate cost (1987 dollars) of methanol on the North Slope would be between $11.84 and $14.84/mm Btu's. The plant-gate cost per gallon of methanol would range from $.79 to $.99 in 1987. In addition, transportation charges of $.16 per gallon ($2.40 per million Btu's) should be added to the methanol figures for direct comparison to the ANGTS costs. 11/

D. Transportation of Methanol

Once the natural gas is converted to methanol it must then be transported to the market in the Lower 48. There are several ways to do this, all of which could be less costly than the ANGTS. These modes include batching the methanol through the TAPS, commingling the methanol with the crude in the TAPS, building a dedicated methanol line parallel to the TAPS, and shipping it along all-marine routes.

An obvious and relatively inexpensive method of moving the methanol off of the North Slope is to batch it through the TAPS line. The line has a design capacity of 2.0 mb/d and an operational capacity of 1.8 mb/d and

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11/ Assumes transportation cost of $5.00/barrel for TAPS and $1.90/barrel by tanker to Long Beach.

that is expected to drop in the latter half of the 1980's as oil production starts to decline. Waterflooding and the production from newer fields (such as Kuparuk, Lisburne, and Duck Island) could make some additional crude oil available, but the amount is highly uncertain and will probably be less than enough to offset expected declines in the current TAPS throughput. At present, there is a surplus capacity of at least 300,000 b/d and possibly more. To use that spare capacity would require one additional pump station on the north side of the Brooks Range and extra storage tanks at the terminal at Valdez. At Valdez, the methanol would be loaded onto conventional tankers which could then go to any destination desired. Because TAPS is already built and fully operational, the additional costs that would be generated by utilizing this method would probably be very low.

Besides the nominal capital cost of facilities, there are a number of advantages to batching. If additional liquid hydrocarbons in the form of methanol were put through the TAPS (a common-carrier pipeline) it would provide more revenue to the line owners and, because of greater operating efficiency, it could allow the TAPS operators to lower the cost of transporting their crude oil. The use of the TAPS for methanol transport also could extend the useful life of the pipeline because the development of current U.S. and Canadian gas reserves could make quantities of methanol available far into the future much longer than the oil. If methanol were converted to gasoline on the North Slope using the new process patented by Mobil, it could also be batched through the TAPS.

The sea leg from Valdez to the U.S. West Coast or to other destinations would be very conventional because methanol can be carried without modification in crude oil tankers. A surplus of such tankers now exists worldwide, so no new ship construction would be necessary. The shipping companies and the maritime unions would certainly welcome the additional business. It is also interesting to note that the Trans-Alaska Pipeline Right-of-Way Authorization Act (P.L. 93-153) prohibits the exportation of crude oil but does not extend to exports of methanol, nor is the price of the product controlled. Another advantage of methanol over crude oil as a tanker cargo is that if it were spilled it would quickly and completely mix with the water and dissipate with no residue. 12/ Any wildlife loss would be due only to the initial high concentration and would be extremely limited. Because of the temporary nature of the disruption of the environment and the lack of residue, the habitat could probably be quickly restored with no long-term effects. Methanol is a normal sea water component (in small concentrations) produced by various organisms and is not alien to the marine environment.

Commingling methanol with crude oil for shipment through the TAPS might be a possibility when large amounts of natural gas are produced as the field begins to decline. Stanford University has developed methods of preparing stable dispersions of crude oil in methanol that could be easily pumped at temperatures below 0 degrees C. 13/ This could be an operational advantage because the mixture would not gel like crude oil if the pipeline

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12/ Sullivan S. Marsden. Society of Petroleum Engineers of AIME, 54th Annual Fall Technical Conference, Sept. 23-26, 1979, SPE 0296, p. 3.

13/ Ibid.

were shut down during sub-zero temperatures. At the destination, the crude oil and methanol could be separated in a refinery through simple distillation.

Another possibility is the construction of another pipeline parallel to TAPS. Some oil companies have expressed reluctance to commit anything other than crude oil to the line because of their expectation that future production from new fields will require the full capacity of the line. A line dedicated to carry about 500,000 b/d of methanol would be much more expensive (about $5 billion), but it would eliminate concerns about overcommitment of the TAPS and about batching. The relatively high cost of this option would seem to make it an unlikely choice at least for the short-term. A rapid increase in the methanol market, however, could quickly change that perception.

Another possible approach is the all-marine route. This would involve the movement of tankers to Prudhoe Bay to load the methanol directly from the "trains." The tankers would then return through the Barrow Strait to their destinations. Because the northern coast of Alaska is ice-bound for most of the year, icebreakers would be required to escort tankers most of the time. This icebreaking technology is readily available and would not appear to present any particular difficulty. The tankers themselves could be built with icebreaking capabilities, but this would be very expensive, would require a new fleet of tankers, and would probably not be cost effective because they would be overbuilt for the openwater legs of their voyages. Conventional tankers following icebreakers, however, could be the lowest cost method of all for moving methanol to the U.S. West Coast if the problems of operating in ice that thick can be resolved. Submarine tankers are also a real possibility, but they would be limited to voyages to the east of Prudhoe Bay because of insufficient water depth in the Bering Strait.

All of these options possess one common characteristic, they could be less expensive than the ANGTS. Some appear to be more practical than others, but they all have unique advantages. If the ANGTS is not built and a decision to produce methanol is made, then the transportation mode considered to be the least costly and most reliable will probably be the one ultimately selected.

E. The Methanol Market

Although methanol may seem like an exotic new fuel, it is not. Early in the development of the internal combustion engine, it was widely touted as the fuel of choice because it worked well, ran cleanly, and could be made from a variety of raw materials. The reason methanol-powered automobiles are not as common today as gasoline-powered ones is due to one reason, cost of feedstock. In the late 19th century, petroleum became so inexpensive that no other fuels could effectively compete, regardless of their other qualities. By 1973, however, those lines had again crossed and diverged. Methanol is now about 25 percent less expensive than gasoline, even after volumes are adjusted for Btu content, and its relative cost could decline further. 14/

The principal reason that producing companies give for not becoming more active in promoting methanol as a fuel is the uncertainty over the market for

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14/ Richard Dopp, Wentworth Brothers, private conversation.

it. The major difference between the circumstances now and in 1977, when the ANGTS decision was made, is that the market for fuel-grade methanol is rapidly forming. This market consists of several components: automotive fuel, diesel fuel, liquefied petroleum gases, turbine and boiler fuel, and gas turbine fuel substitution.

Methanol can be used as an automotive fuel in several ways. It can be blended with gasoline as a gasoline stretcher and octane enhancer (or converted with isobutene to MTBE as a substitute anti-knock compound), converted directly to gasoline, or used as a "neat" (100 percent) motor fuel.

Most of the current interest in methanol centers around its acceptance as a blending agent in gasoline. ARCO is now marketing a fuel called Oxinol, which consists of 4.8 percent methanol and 4.8 percent tertiary butyl alcohol. Anafuels Unlimited recently received EPA waivers to produce and to sell a gasoline blend fuel consisting of 15 percent methanol and higher alcohols. Other companies are planning to market similar fuels. The advantages of adding methanol to gasoline are very apparent. Driveability is greatly increased because of methanol's blending octane value (BOV) of 120 to 130. Thus engine knock, a chronic problem as carbon builds up in the cylinders of modern engines, can be eliminated at a cost far less than that of the aromatics and other compounds currently used. Methanol is less toxic than the aromatics and does not require premium crude oil as a raw material. In addition, discontinuing the use of aromatics would remove much of the pressure on the supply of aromatics (now used to increase octane) a problem which has long concerned the petrochemical industry. It could also be used in place of many liquefied petroleum gases.

Even though methanol contains 50 percent fewer Btu's per gallon than does gasoline, it enhances the combustion efficiency and does not limit range as much as its energy content would suggest. In some tests, the methanol/gasoline blends have shown fuel economy gains of up to 8 percent over gasoline alone, plus substantial improvements in emission reduction. Blends of up to 15 percent methanol can be accommodated in most modern automobiles without modification. The only negative in this application is that seals and gaskets designed for non-polarizing fuels like gasoline can lose their strength when exposed to polarizing fuels such as methanol in high concentrations, especially in the carburetor and fuel pump. These, however, can be replaced with appropriate materials at relatively low cost. MTBE, a methanol derivative, is already in wide use as lead substitute for gasoline.

Even more attractive than blends is the prospect of methanol as a "neat" fuel. It has very positive aspects including the virtual absence of any undesirable emissions and the elimination of engine knock. Dr. Edward David, President of Exxon Research and Engineering Company, speaking at the 1981 convention of the American Institute of Chemical Engineers, made this observation: "Indeed, methanol looks very intriguing, both as an octane-improving gasoline extender, and eventually, as a neat automotive fuel in its own right. The octane rating of neat methanol is high enough to allow, in theory, jacked-up compression ratios and direct injection in lean-burn engines that could attain efficiencies perhaps thirty-percent higher than comparable gasoline engines." The biggest disadvantage of neat methanol as an auto fuel is its low vapor pressure (compared to gasoline) which has always presented annoying cold-start problems.

In recent years, however, a number of methods have been developed to deal with this problem. Additives with higher volatility (such as isopentane can be added in amounts of up to 10 percent to improve this characteristic. The methanol can be vaporized by a heat exchanger in the fuel tank (Texas A&M system) after starting the engine on gasoline. Volkswagen has also developed a device using heat to improve cold-start characteristics. Perhaps the most ingenious solution to this problem is a device made by the Webster-Heise Corporation which apparently eliminates the problem altogether by totally atomizing the fuel to a droplet diameter of less than 10 microns and thoroughly mixing it with the proper amounts of air in the manifold. The greater surface area of the fuel droplets and the even distribution to the cylinders appears to greatly enhance the combustion of the fuel even in cold starts. The reduction in the amount of liquid fuel reaching the cylinder also reduces the need for corrosion inhibitors and reduces the dilution of engine lubricants.

A problem widely mentioned as a problem with methanol/gasoline blends is phase separation in the presence of water. Methanol has a strong affinity for water (from condensation in the fuel tank and runoff into service station tanks) and will leave a solution with gasoline to combine with it, which can cause operational problems. To guard against this possibility, T-butyl alcohol or other higher alcohols are added to methanol/gasoline blends. As a result, fleet operators with extensive experience with both methanol blends and "neat" methanol have not reported water to be a problem.

Reduced air pollution is a most attractive feature of methanol fuel. Because the flame temperature is much less than that of gasoline, very little NOx is formed. Carbon monoxide and unburned hydrocarbons are also reduced and may be reduced even further with a Webster-Heise system because during combustion more of the CO would proceed to CO_2 and more of the hydrocarbons would be consumed. Because of its high natural octane, no lead or toxic aromatics would be needed to prevent detonation.

Only formaldehyde emissions could be considered a negative, for combustion of methanol. This is a product of incomplete combustion and is present in very minute quantities (less than 8 parts per million). At those levels, formaldehyde (which can be carcinogenic) would be more of an irritant than a hazard, although the human nose is sensitive to the compound and could detect it even in small quantities. Fortunately, the catalytic converters found on modern (1975 or later) automobiles remove virtually all of the aldehydes. It is unlikely, therefore, that this would be a problem of any real consequence.

A large market for m anol could develop in the electric power industry if the cost does not exc d that of current fuels. Once storage facilities and fuel lines are size or the lower energy content per unit volume of methanol, the rating of a powerplant can be increased by more than 10 percent. This greater output from the same number of BTU's is due to the greater efficiency of combustion and better mass-flow characteristics. Only minor burner modifications are necessary. Methanol is considered to be an ideal fuel for combined cycle plants because its low emissions and the low capital investment per kilowatt-hour.

Methanol is considered to be uniquely well-suited to this purpose because the combustion results in very low levels of pollution. Because of the longer burning time in a powerplant, the formaldehydes are consumed and even that irritant is removed. NOx emissions are about one-tenth that emitted by boilers using No. 6 fuel oil (resid), and no sulfur is present in the fuel so none can be emitted as SO2, which can form acid rain. The powerplant use of methanol could be very attractive in urban areas where smog is a chronic problem. In fact, the City of Los Angeles has requested proposals to convert several of its powerplants with a combined capacity of 2,000 megawatts. The California Energy Commission has estimated that the electric utilities in California alone could, if converted, absorb a large part of the methanol production from the North Slope. It is likely that the limiting factors on powerplant use of methanol would be supply and cost rather than demand. General Electric has observed that there are no technical barriers that would impede the use of methanol should sufficient feedstocks become available. 15/

F. Obstacles to Implementation

Despite its apparent advantages and potential, methanol has not been seriously considered as an alternative to the ANGTS project. Many companies, especially the North Slope gas producers have examined the prospect but have not publicized their findings. There are several reasons for this, all of which are equally important.

The ANGTS project was conceived and promoted at a time when natural gas was in short supply and severe curtailments were common. In this crisis atmosphere, a high priority was placed on the construction of a pipeline to deliver North Slope gas to the Lower 48, the competition for which was

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15/ Robert K. Alff, Alcohol and Electric Power, May 7-8, p. 1.

eventually won by the sponsors of the ANGTS. Since that time, however, the partial deregulation of gas, the decontrol of oil, and the more uniform distribution of gas that was formerly consumed primarily in the intrastate market has diminished the sense of emergency. The procedures established by Congress to expedite this project, however, remain intact and action on them has proceeded to the point where no methanol plants would be built on the North Slope while the ANGTS is being considered. The decision by President Carter and the recommendation by President Reagan on the waiver package, plus assurances to Canada that the United States will proceed are formidable obstacles. There is also concern over possible Canadian reaction to a decision not to build the ANGTS, part of which is being pre-built there but it could carry Albertan gas if the rest of the ANGTS were not completed. The State of Alaska has also expressed its support for the ANGTS because of the construction and tax revenue it would receive plus the fact that it was further along in the permitting process than any competing alternative.

Against this set of political considerations, it would be unreasonable to expect any of the gas producers to actively promote another alternative while the ANGTS is still pending. All of the companies have considered the methanol alterantive in terms of their own perspectives, but none will support it, even if so inclined, until the ANGTS waiver and financing questions are resolved. Some of the companies have privately expressed concern over the escalating cost of the ANGTS at a time when they need capital for the exploration and development of new petroleum fields and for the reconfiguration of refineries. The oil companies, because of the many sensitivities involved, probably do not wish to be responsible for the failure of the ANGTS. If it were to fail, the companies would probably take a fresh look at methanol and some are already doing so. It is also apparent that if the ANGTS is built and the oil companies become equity owners in it (one of the provisions of the waiver package), it is extremely unlikely that any methanol plants would also be built on the North Slope. Because of the huge investment that the ANGTS would require of the oil companies, they would be committed to maximizing the gas flow through it.

Another important factor is that the methanol alternative has become much more practical in the past year because of the rapid development of a market for methanol fuel. At the time the ANGTS decision was made, the use of methanol as a fuel was virtually nonexistent. Since then, however, its use as an octane booster for premium unleaded gasoline and its potential as a total substitute for gasoline and powerplant fuel has made its large-scale production much more attractive. Methanol has always been plagued by the "chicken-and-egg" problem because no one would make it in quantity unless he could be assured it would be sold at a profit. 16/ In addition, there was no convenient infrastructure to market it. Now that the Environmental Protection Agency has permitted its use as a gasoline additive, however, the potential market for methanol fuel is much larger, but has yet to be fully realized. An EPA official recently claimed that methanol is "the clear choice for the transportation fuel of the future"

16/ Thomas J. Feaheny, Ford Motor Company, interview by CBS News, October 1981.

but that a blend of up to 5 percent methanol would be needed as an intermediate step to enable large-scale plants to be built. 17/

There also may be some concern on the part of the oil companies about methanol being a new commodity for them. Very few oil companies have had much experience with it and may be unsure of its place in their operations. There may also be some concern that the conversion of the gas to methanol by the North Slope producers and its marketing by them might produce an antitrust issue which they would want to avoid. It very well could cause some protest from the gas transmission companies and electric utilities because they can pass on the price of gas, however high it might be, to its customers. It is far less certain that they could do that with methanol, although its use would allow them to increase their power output by ten percent and to greatly reduce their powerplant emissions.

The rapid development of a large source of methanol could be a source of concern to the producers of chemical-grade methanol. This product is 15th in terms of sales of organic chemicals with 1979 sales of 1.1 billion gallons valued at $507 million. 18/ Some of these producers have expressed some concern over the potentially destabilizing influence on their market of a large new source of methanol that would double the existing supply of methanol. Even though North Slope methanol would be fuel grade, it could be processed further into chemical-grade methanol for which the market has been depressed in recent years.

17/ Alcohol Week, November 16, p. 2.

18/ Chemical and Engineering News, April 2, 1979, p. 2.

The traditional negatives associated with methanol may no longer apply to the same degree, but they still constitute obstacles which are difficult to overcome. The energy lost in conversion is probably the one most commonly mentioned because chemical-grade methanol plants often consume 30 to 40 percent of the gas in processing. In the large fuel-grade plants this loss could be as low as 22 percent and could decline even more with technological advances. Most of that loss, however, can be regained through its efficient combustion. The lower Btu content of methanol is often cited as a problem, and it could limit range to some extent, but much of this is offset by its combustion efficiency. Instead of a ratio of two units of methanol to one unit of gasoline, for example, the effective ratio is about 1.3 to 1, despite a Btu content half that of gasoline. The cold-start and driveability problems of methanol fuel have been effectively solved. The problem of the seal and gasket deterioration in automobile engines is a real one but is easily solved by replacing them with materials that are not affected by that type of fuel. None of these problems are insuperable and appear to be more than offset by the economic, environmental, and energy conservation aspects of methanol fuel use.

G. Conclusion

The emergence of a market for fuel-grade methanol has made proposals to produce methanol from remote resources more attractive than in the past. Numerous domestic and foreign corporations are actively planning conversion facilities and transportation systems. Canada and Mexico have been especially active in increasing their methanol production severalfold. It is apparent that methanol could become a significant part of the fuel mix and has attracted the interest of most of the major petroleum companies. The initial entry of methanol fuel into the marketplace has been in the form of an octane booster and supply stretcher and may be followed by "neat" methanol as an automotive and powerplant fuel.

Proponents of the methanol alternative believe that the problem of transporting the North Slope gas presents a unique opportunity for methanol to break the "chicken-and-egg" cycle that has always plagued it. If the North Slope gas were converted to methanol and if its cost were competitive it is likely that all of the methanol could be marketed. The two to three years that would be needed to build the methanol trains could provide the time necessary to make powerplant conversions and to build gasoline/methanol blending facilities. Once the certainty of supply is resolved, end users could have the opportunity to make definite plans and investments to facilitate its utilization as a fuel.

For a change of this magnitude to take place in the fuel manufacturing and marketing infrastructure, the economics must be compelling. Recent estimates indicate that North Slope methanol could be delivered in the form of a premium liquid transportation fuel for less cost than the natural gas and with a lower loss of resource. The proponents of the methanol alternative maintain that it is more attractive economically than the ANGTS, even with the advantage given to gas pipelines by the regulatory process. If the waiver package fails or if the ANGTS is not successfully financed, then methanol could be the system of choice.

The methanol alternative is not without its disadvantages. It is a relatively new product in the fuel mix and has a limited distribution system as such. It would require some modification in automobiles and powerplants that would use it, except in blends of 15 percent or less with other fuels. The modifications would be necessary to prevent the deterioration of engine seals, to correct cold-start problems, and to adjust line sizes for greater flow (in powerplants). Most of the problems, however, may be institutional. The petroleum companies may be unsure of its place in their marketing plans because it is a product with which they have had limited experience. As a result, its initial use as a automotive fuel would likely be as an octane-boosting additive rather than as a neat fuel. Its use in powerplants might also be opposed by transmission companies that would otherwise supply coal, gas, or oil.

Perhaps the greatest single obstacle to methanol from the North Slope is competition from methanol made from coal. Several large coal-to-methanol plants are planned for the Southwestern United States, and the cost of methanol from these plants could be less than that of North Slope methanol. Sun Tech (a division of Sun Oil Co.) has estimated that methanol could be made from Western coal (selling at $10 per ton at the mine mouth) for $.55 per gallon. 19/ If the methanol contained 15 percent higher alcohols it could sell at the plant for $.60 per gallon, with 30 percent higher alcohols it could sell for $.68. Wentworth Brothers, Inc. has estimated plant gate costs as low as $.40 to $.50 per gallon. The capital investment for coal conversion plants would probably be lower because of their Lower-48

19/ Alcohol Week, November 16, 1981, p. 3.

location, but that would be offset to some extent by the extra processing needed to convert coal to methanol. By the time these plants would become operational, the market potential for methanol could be large enough to accept methanol from both sources, particularly since there would be an interval of several years before supplies would actually be available. If the methanol from coal were substantially less than methanol from North Slope gas, however, it could make the latter less attractive as an alternative to the ANGTS.

The availability of methanol made from North Slope gas would greatly accelerate the trend toward the use of methanol as a fuel. Penetration of the gasoline and fuel oil markets on a large scale would very likely encourage similar conversion efforts elsewhere. Methanol could be made from a wide variety of raw materials such as natural gas, coal (regardless of sulfur content), agricultural byproducts, timber waste, and any other concentrated hydrocarbon resource. The benefits to be derived from such a development include cleaner air, more efficient utilization of remote or marginal resources, security of supply, and a large reduction in the importation of foreign oil.

APPENDIX I

THE COST OF CONVERTING NORTH SLOPE NATURAL GAS TO METHANAL

TABLE IV

COST OF CONVERTING NORTH SLOPE NATURAL GAS TO METHANOL

(51,000 Tons of Methanol Per Day)

		Case I*	Case II**
Total Capital Investment (1981 $)		$6.9 billion	$ 9.0 billion
Annual Operations and Maintenance (1981 $)		$658.0 million	$658 million
Annual Feedstock Costs (1981 $)			
Natural gas	$0/1,000 scf	$ 0.0	$ 0.0
Natural gas	$1/1,000 scf	$ 0.66 billion	$ 0.66 billion
Natural gas	$4/1,000 scf	$ 2.64 billion	$ 2.64 billion
Natural gas	$8/1,000 scf	$ 5.28 billion	$ 5.28 billion
Cost of Methanol in 1981 $			
Natural gas	$0/1,000 scf	$ .19/gal.	$ .22/gal.
Natural gas	$1/1,000 scf	$ .31/gal.	$ .34/gal.
Natural gas	$4/1,000 scf	$ .67/gal.	$ .70/gal.
Natural gas	$8/1,000 scf	$1.15/gal.	$1.17/gal.
Cost of Methanol in 1987 $			
Natural gas	$0/1,000 scf	$ .34/gal.	$ .39/gal.
Natural gas	$1/1,000 scf	$ .55/gal.	$ .60/gal.
Natural gas	$4/1,000 scf	$1.19/gal.	$1.23/gal.
Natural gas	$8/1,000 scf	$2.03/gal.	$2.08/gal.

*Case I assumes that there will be 17 plants built at a cost of $375 million each.

**Case II assumes that there will be 17 plants built at a cost of $500 million per plant and an inflation rate of 10 percent per year. All assumptions provided by the Congressional Research Service.

Source: Derived from JPL Required Revenue Methodology as found in Energy System Economic Analysis (ESEA) Methodology and Leser's Guide, JPL Publication 5101-102.

System Variables

Base Year:	1981
Year of Commercial Operation	1987
Plant Life	20 years
Annual Plant Output	5.5 billion gal./yr.
Discount Rate*	.1051
General Inflation Rate	.10
Capital Escalation Rate	.12
O&M Escalation Rate (1st 10 years)	.10
O&M Escalation Rate (2nd 10 years)	.08
Percentage of Plant 5-year Depreciable	.95
Percentage of Plant 10-year Depreciable	.05
Combined Effective Income-Tax Rate	.51
Investment Tax Credit	.10
Insurance, Other Taxes, etc.	.01
Debt Equity Ratio	75/25
Cost of Debt	.15
Return on Equity	.20

*Discount Rate, k, is after-tax opportunity cost of investment defined as

$$k = (1-\tau)k_D \cdot f_D + k_E \cdot f_E$$

Where τ is the combined effective tax rate, k_D is the market rate for debt, f_D is the fraction of investment that is debt, k_E is the after-tax return to equity, and f_E is the fraction of investment that is equity.

Total Capital Requirement (1981 $)	Case I	Case II
	(billions of $)	
1. Total Plant Investment		
a. Physical Plant	$3.870	5.060
b. Project Contingency (40%)	1.550	2.020
c. Cold Weather Contingency (totally enclosed) 20%	1.080	1.420
2. Catalysts and Chemicals	0.010	.010
3. Royalties (.5% TPI)	0.033	.043
4. Start-up Costs (5% TPI)	0.325	.425
5. Inventory Capital (1% TPI)	0.065	.085
Total Capital Requirement (1-5)	6.935	9.043

Schedule of Expenditures

Year	% Total	1981 $	1981 $
1982	10%	$.693	------
1983	50%	$3.466	.850
1984	30%	$2.080	4.250
1985	10%	$ .693	2.550
1986	---	------	.850

<u>Operating Costs (1981 $)</u>

1.	Operating Labor	$150.0 million/year
2.	Overhead (.15% of O.L.)	$22.5 million/year
3.	Maintenance (7% of TCR)	$485.3 million/year
	Subtotal	$657.8 million/year

4. Feedstock Costs (c=cost of gas $/1,000 scf)

($c/1,000 scf)(20)(100x10) = $2,000 c x 10 /day

service factor = 330 day/year

$660 c x 10 /year (1981 $)

c	Feedstock Costs (1981 $)
$0	$0/year
$1	$660 x 10 /year
$4	$2,640 x 10 /year
$8	$5,280 x 10 /year

APPENDIX II

NATURAL GAS RESOURCES OF ALASKA

NATURAL GAS RESOURCES OF ALASKA*

Alaska is located at the northern end of the American Cordillera, which is a continuous mountain system that extends along the entire length of western North and South America. Thus, Alaska is similar geologically to other regions in this long system of mountains. Dynamic earth processes continually alter Alaska. It is one of the most volcanic and earthquake-prone areas of the world. In the north, permanently frozen ground (permafrost) is common and constitutes an operational problem in hydrocarbon development.

A. ALASKAN GAS PRODUCTION, RESERVES, AND RESOURCES

Total gas production on Alaska in 1979 was 225.3 billion cubic feet, about 182.5 billion cubic feet of which was from Cook Inlet. 1/ Proved gas reserves at the end of 1979 were estimated to be 31.9 trillion cubic feet (tcf). Of this amount, 5.2 tcf is in fields not associated with oil, mostly located in Cook Inlet. The remaining 26.7 of gas reserves is associated with oil, almost all being in the gas cap of the super-giant Prudhoe Bay oil field on the Artic North Slope. 2/

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*/ Prepared by Joseph P. Riva, Jr., Specialist in Earth Sciences, Science Policy Research Division, Congressional Research Service.

1/ Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979. American Petroleum Institute, American Gas Association, Canadian Petroleum Association, v. 34, June 1980. p. 109 and Wilson, Howard M. Cost Squeeze Retards Cook Inlet Output. Oil and Gas Journal, Feb. 4, 1980, p. 37.

2/ Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979, op. cit., p. 125.

The U.S. Geological Survey recently updated for 1980 the undiscovered recoverable natural gas resources of Alaska as follows (in trillions of cubic feet): 3/

	95% probability	5% probability	statistical mean
Onshore Regions	19.8	62.3	36.6
Offshore Regions	33.3	109.6	64.6
Total			101.2

The Potential Gas Committee (an industry, government, and academic group of geologists and engineers based at the Colorado School of Mines) also updated for 1980 their previous estimates on the gas resource potential of Alaska as follows (in trillions of cubic feet): 4/

	Probable	Possible (Most Likely)	Speculative
Onshore	6	16	28
Offshore	2	13	80
Total	8	29	108

It is evident that the Potential Gas Committee is less optimistic in regard to Alaskan gas potential than is the U.S. Geological Survey. The 1980 Potential

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3/ Dolton, G. L., et al. Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary. Open File Report 81-192, U.S. Geological Survey, 1981. p. 6.

4/ Potential Supply of Natural Gas in the United States. Potential Gas Committee and Potential Gas Agency, Colorado School of Mines, Golden, Colorado, May 1981. p. 22.

Gas Committee estimates for Alaska are about 30 percent lower than their 1978 estimates, while the Geological Survey's 1980 estimates are somewhat higher than their previous estimates, which were made in 1975.

Alaska is still a frontier area. However, recent seismic surveys and exploration drilling have demonstrated that areas earlier thought to be highly prospective will be much less promising. Negative exploratory results in portions of the Arctic basin, the Gulf of Alaska, Lower Cook Inlet, and in the Kodiak area have resulted in reductions of estimates of potential gas resources for these regions. 5/

There have been a number of wildcat wells drilled in the National Petroleum Reserve on the North Slope without a major discovery, but this area is still considered to have some hydrocarbon potential. Also, a number of large and promising areas such as the Arctic Wildlife Refuge, the Norton Basin, the Chukchi Sea, and the Navarin Basin have not as yet been drilled. These frontier areas could contain substantial gas resources as could portions of such already partially drilled areas as the Arctic and Cook Inlet basins. 6/

It is interesting to note that, contrary to the Geological Survey, the Potential Gas Committee appears to consider that onshore Alaska is likely to have a greater gas potential than offshore Alaska. However, in the speculative category their offshore estimate is considerably higher than their onshore estimate and not greatly lower than the high offshore estimate of the Geological Survey. This, of course, indicates the uncertainty of offshore resources especially in areas where there has been no drilling. The 13 tcf estimated as being a possilbe offshore potential by the Potential Gas Committee would indicate the future discovery

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5/ Gas: What's Underground? The Energy Daily, May 26, 1981, p. 6.

6/ Ibid.

of relatively few new gas fields, as offshore gas fields in Alaska must be very large to be commercial.

Gas production in Alaska has been hampered by lack of local markets. There are several fields in the Cook Inlet area which are either not on production or are capable of greater output. These will be developed when a long delayed Liquid Natural Gas project with two California utilities is completed. 7/ Also, the associated gas (about 26 tcf) in the Prudhoe Bay gas cap cannot be produced until a gas pipeline to the markets of the lower 48 States is constructed.

Following is a brief discussion of the most favorable areas in Alaska for natural gas discoveries.

B. GULF OF ALASKA

The sedimentary basin in the Gulf of Alaska region contains a thick sequence of Tertiary age continental and marine strata. Structurally, the basin is composed of east-west trending features, including faults, similar to those found onshore. Onshore exploration in the region was revived in the 1950s and a number of unsuccessful wildcat wells were drilled, a dozen of which were over 10,000 feet in depth. There had been one small, earlier success, the shallow Katella oil field, discovered in 1902. The field, now abandoned, produced about 150,000 barrels of oil from 22 wells. This onshore field demonstrated that hydrocarbons had been generated in the basin. Since further onshore exploration was unsuccessful and drilling locations were limited along the narrow shoreline between the mountains and the Gulf, seismic surveys were run offshore and several structures were defined. A Federal lease sale was held in April 1976 in which the petroleum

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7/ Wilson, Howard M., op. cit.

industry paid $560 million for 76 tracts in the central part of the gulf. Since that time, 10 holes have been drilled at a cost estimated to be about $15 to $20 million each. All of them were dry and abandoned. Such total failure was difficult to anticipate. The drilling encountered good reservoir rock and the large structures that the seismic records had indicated, but no petroleum was present. One problem could be depth; two relatively shallow, prospective, onshore formations were not found even in the deeper offshore wells, which went almost to 18,000 feet. Whether still deeper holes would encounter these older formations and whether they would contain commercial oil and gas in not known. 8/ However, there are indications, resulting from highly specialized geophysical analysis, that commercial quantities of hydrocarbons are not likely to occur in the central part of the Gulf of Alaska, because of the general shaliness and persistently calcareous nature of the sediments, factors that detract from the potential for thick reservoirs which are porous and permeable. 9/

Following the failure to discover hydrocarbons in the central Gulf, the U.S. Geological Survey announced that the results of chemical analysis of dredge samples from the eastern Gulf indicated the presence of a potential source rock for natural gas and possibly also for oil. 10/ A Federal lease sale was held in October 1980 for tracts in the eastern portion of the Gulf of Alaska. High bids totaled $118 million on 37 tracts receiving bids, most of the money

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8/ Wilson, Howard M. Alaska Explorers Still Sure Big Finds Coming. Oil and Gas Journal, Feb. 26, 1979. p. 76.

9/ Aud, B. W. Hydrocarbon Potential in Gulf of Alaska--What Happened? Oil and Gas Journal, Jan. 29, 1979. p. 224.

10/ Clues to Petroleum in Gulf of Alaska. Dept. of the Interior News Release, Geological Survey, Feb. 9, 1979.

being spent for a large anticline about 40 miles offshore. The anticlinal structure is thought to contain strata that is older than those in the nonproductive central Gulf. 11/

Another offshore Federal lease sale which will also include tracts in the Gulf of Alaska is scheduled for October 1985. The Department of the Interior has asked the oil industry to indicate its interest in a chance to bid on about 100 million acres of onshore Federal lands covered by the D-2 Alaska lands legislation. It is possible that onshore areas determined to be favorable for petroleum exploration may be opened for competitive bid before the end of 1981. 12/ A significant amount of this acreage is in the onshore Gulf of Alaska region where there are known oil seeps along with the abandoned Katella oil field. It is possible that tracts in this region will be nominated for inclusion in the Federal onshore leasing program.

The U.S. Geological Survey, in its latest estimate of undiscovered recoverable gas resources, projects from 0 to 10.8 tcf (with a statistical mean of 2.2 tcf) for the Gulf of Alaska, a reduction from earlier Survey estimates. Onshore undiscovered recoverable gas in the Gulf of Alaska region is estimated to range from 0 to 1.7 tcf (with a statistical mean of 0.3 tcf). 13/, 14/

11/ Wilson, Howard. ARCO Dominates Gulf of Alaska Bidding. Oil and Gas Journal, Oct. 27, 1980. p. 45.

12/ Wilson, Howard M. Interior Seeks Industry Interest in Alaska Tracts. Oil and Gas Journal, May 18, 1981. p. 48-49.

13/ Dolton, G. L., et al., op. cit., p. 8, 10, and 11.

14/ The U. S. Geological Survey's undiscovered recoverable gas estimates given for each region are based upon an analysis and review of the petroleum geology, exploration history, volumetric-yield, finding-rate, and geologic structure. Because of the uncertainty involved in estimating undiscovered resources, the estimates include a range of values as follows: the low resource estimates (often zero) correspond to a 95 percent probability of more than that amount;

(continued)

C. COOK INLET--ALASKA PENINSULA

The Cook Inlet Petroleum Province extends from the Chitina Valley southwestward across Cook Inlet and Shelikof Strait to the end of the Alaska Peninsula. It is a lowland which is bounded on the north and west by the Alaska Range and on the south by the Keni-Chugach Mountains. Offshore drilling tracts are located in waters up to 600 feet deep, with storm waves in excess of 65 feet. 15/

Cook Inlet is both a topographic and a structural basin that contains about 60,000 feet of Mesozoic and Cenozoic sediments. The older Mesozoic strata, which crop out around the edge of the basin, are mostly of marine origin, while the thick younger Tertiary rock sequence is largely nonmarine. Oil and gas seeps are known in the Mesozoic rocks. Hydrocarbon production, however, has mostly come from the overlying Tertiary rocks from structural traps lying along the northerly structural grain of the region.

Oil was discovered in commercial quantities in the upper Cook Inlet area in 1957 at Swanson River on the Kenai Peninsula. Since that time six oil fields have been developed and about 18 gas fields have been found. Offshore drilling began in 1962 with the discovery of the North Cook Inlet gas field and the Middle Ground Shoal oil and gas field. 16/ Offshore development followed rapidly. There are about 15 offshore platforms which produce oil and gas from the fields

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(continued) the high resource estimates correspond to a 5 percent probability of more than that amount; while the statistical mean is the estimate of the quantity of the resource associate with the greatest likelihood of occurrence. Since the estimates for each region are probabilities, they are not additive for the State as a whole.

15/ Hanley, P. T., and W. W. Wade. New Study Analyzes Alaska OCS Areas. Oil and Gas Journal, Jan. 12, 1981. p. 75.

16/ Mueller, Ernst. Alaskan Oil--the Energy Crisis and the Environment. Arctic Bulletin, v. 1, no. 5, 1975. p. 186.

in the inlet. In 1979 gas production from upper Cook Inlet totaled about 182.5 billion cubic feet, mostly from the Kenai, Beluga River, and North Cook Inlet fields. Part of the gas is exported as liquid natural gas to Japan and the remainder is used by local industry and for South Alaska consumption. 17/ Several gas fields are shut-in or are capable of greater production, but these will not be developed until markets are available, either in Alaska or California. The Upper Cook Inlet area, where the producing fileds are located, shows little additional promise for offshore hydrocarbon discoveries, but there are a number of onshore areas yet to be explored on the Kenai Peninsula and in the Chitina Valley - Copper River region. 18/ Lower Cook Inlet, thus far, has proved an expensive disappointment. Available data indicate that it has a thinner stratigraphic section and also less structural potential than the upper inlet. The exploratory holes drilled to date have been dry. The U.S. Geological Survey recently estimated that from 0.7 to 11.8 tcf of gas may remain to be discovered offshore in the Cook Inlet - Kodiak area (with a statistical mean of 3.2 tcf). Onshore Cook Inlet - Alaska Peninsula, including the Copper River area, undiscovered recoverable gas estimates range from 1.1 to 9.3 tcf (with a statistical mean of 3.7 tcf). 19/ Another offshore Federal lease sale is scheduled for the region in October 1985.

D. NORTH ALEUTIAN (BRISTOL BAY) BASIN

The Bristol Bay basin is the most explored and best known basin on the Bering shelf. Seismic work has been underway in the region since 1966 and

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17/ Wilson, Howard M., op. cit.

18/ Ibid.

19/ Dolton, G. L., et al., op. cit., p. 8, 9, 11.

surface geology and expoloratory drilling have been carried out along the southeast margin onshore. Some of the holes contained minor oil shows. The basin, located on the north side of the Alaska Peninsula, covers an area of about 46,000 square miles, and is one of the largest Tertiary basins around the Pacific rim. Marine seismic data indicate that the Bristol Bay basin contains a very thick section of gently folded, Tertiary marine and non-marine clastic and volcanic rocks. Several structural highs are located at the margins of the basin and offer good potential for hydrocarbon accumulations. 20/ The Cenozoic rocks which appear to offer the best reservoir potential are Miocene sandstones.

The offshore portion of the basin lies under rather shallow water, 50 to about 400 feet, at the southern extremity of the Bering Sea ice. A Continental Offshore Stratigraphic Test (COST) well is planned for the basin in August 1982. 21/ Two Federal lease sales are scheduled for the area, one in April 1983 and the second in April 1985. The U.S. Geological Survey recently estimated that from 0 to 5.6 tcf of recoverable natural gas may exist in the Bristol Bay basin offshore (with a statistical mean of 1 tcf). Estimates for the onshore parts of the basin range from 0 to 2.3 tcf (with a statistical mean of 0.5 tcf). 22/

E. ST. GEORGE'S BASIN

The St. George basin is located on the Bering Sea continental shelf between the Pribilof Islands and the Alaska Peninsula. Lying under 300 to 500 feet of

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20/ Hanley, Peter T., and William W. Wade. Bering Basins Show Good Potential. Offshore, April 1981. p. 127.

21/ Offshore West Alaska Basins Are Hot Prospects. Oil and Gas Journal, April 13, 1981. p. 91.

22/ Dolton, G. L., et al., op. cit., p. 8, 11.

water, the basin, as defined by seismic surveys, is an elongate Tertiary sedimentary depression, caused by a northwest-trending structural graben 23/ about 200 miles long and 20 to 30 miles wide, which is filled with more than 30,000 feet of essentially unfolded Eocene to Recent sediments. 24/ The rocks that appear to have the greatest reservoir potential are Miocene sandstone units, while the best source rocks appear to be Eocene and Oligocene shales which occur deep in the graben. Hydrocarbon traps which may occur include basement highs on the margins and within the deep graben and fault closures against the steep basin walls. 25/

A COST stratigraphic hole has been drilled in the St. George basin and a second is planned. Three Federal lease sales are scheduled (February 1983, December 1984, and December 1986). The U.S. Geological Survey estimates that the basin may contain from 0 to 10.7 tcf of undiscovered recoverable natural gas, with a statistical mean of 2.3 tcf. 26/

F. NAVARIN BASIN

The Navarin basin is the largest of the Bering Sea basins (300 miles long by 160 miles wide). It is located between the Pribilof Islands and Cape Navarin in the Soviet Union. The northwestern part of the basin lies within Soviet territory, but the exact boundary has not been resolved. The basin is a

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23/ An elongate, depressed crustal unit, bounded by faults on its long sides.

24/ Hanley, Peter T, and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 121.

25/ Ibid., p. 124.

26/ Dolton, G. L., et al., op. cit. p. 8.

graben produced by tensional faulting along the continental margin and is filled with 35,000 feet of interbedded sandstone and shale of probable marine origin, ranging in age from Eocene to Recent. 27/ Seismic surveys have indicated that the upper part of the Tertiary section (Miocene and Pliocene) contain potential sandstone reservoirs. Seismic reflection data also have revealed several hundred "bright spot" anomalies, which may be related to shallow gas deposits, and deeper "bright spots," which could correspond to deeper petroleum deposits. Possible traps include sediment drape over basement hights and fault closures within the basin. 28/

Favorable seismic indications and recent Soviet discoveries onshore in eastern Siberia have resulted in evaluations of the Navarin basin as the most prospective of the Bering Sea basins. However, operating conditions will be extremely difficult. Navarin basin drilling will be hundreds of miles from an operations base and must be done in the summer to avoid ice, but even in summer storms are violent. 29/ A COST stratigraphic well is planned for the basin in 1983. Federal lease sales are scheduled in March 1984 and March 1986. The U.S. Geological Survey estimated that undiscovered recoverable gas resources in the Navarin basin range from 0 to 24.9 tcf, with a statistical mean of 5.6 tcf. 30/

G. NORTON BASIN

The Norton basin is located between the Seward Peninsula and the Yukon delta. It consists of a series of west-northwest trending Late Cretaceous

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27/ Hanley, Peter T., and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 127.

28/ Ibid.

29/ Offshore West Alaska Basins Are Hot Prospects, op. cit., p. 92, 96.

30/ Dolton, G. L., et al., op. cit., p. 8, 9.

normal faults which form downdropped grabens separated by uplifted horsts. 31/ The grabens contain the thickest sediment fill, up to 23,000 feet, while the sediment thickness over the horsts is generally thinner than 10,000 feet. The best reservoir potential is thought to be in Late Miocene and younger rocks. Potential traps are structural closures produced by sandstones draped over the horsts. 32/

Water depths in Norton Sound range from 25 to 150 feet. In the inner Sound, where water depths are 60 feet or less, artificial gravel islands would permit year-around drilling. In the deeper, open waters winter ice would limit drilling to the 4 to 6 month summer open water season.

A stratigraphic COST well has been drilled to 14,683 feet in Norton Sound. This well, along with geophysical surveys and onshore geological studies (which include data from shallow gas wells and gas seeps), provide the information for evaluations of the basin's petroleum potential. The U.S. Geological Survey recently estimated that the Norton Basin may contain from 0 to 5.5 tcf of undiscovered recoverable natural gas, with a statistical mean of 1 tcf. 33/ Federal lease sales are scheduled for November 1982, October 1984, and October 1986.

H. HOPE BASIN AND NORTH AND CENTRAL CHUKCHI SEA BASINS

The Hope basin is an offshore extension of the Selawik basin (beneath the Chukchi Sea) which has been tested by two wells drilled onshore near Kotzebue Sound. Since both wells were dry, the basin has been downgraded somewhat in

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31/ An elogate, uplifted crustal unit, bounded by faults on its long sides.

32/ Henley, Peter T., and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 121.

33/ Dolton, G. L., et al., op. cit., p. 8.

hydrocarbon potential. 34/ Seismic surveys indicate that the basin is moderately deep with large basement faults. It is thought to be filled with Late Cretaceous and Tertiary marine and non-marine clastic sediments. 35/

The U.S. Geological Survey's most recent estimate for undiscovered recoverable gas in the Hope basin ranges from 0 to 1.8 tcf, with a statistical mean of 0.3 tcf. The Survey noted, however, that the estimated quantities can be considered recoverable only if recovery technology permits their exploitation beneath Arctic pack ice. Such technology has not as yet been demonstrated. 36/ A Federal lease sale is scheduled for the Hope basin in July 1985.

North of the Hope basin, two deep Mesozoic basins underlie the Chukchi Sea. The North and Central Chukchi basins are divided by the Barrow arch, a subsurface structural ridge. The Central basin contains Mississippian-to-Jurassic sediments overlain by organic-rich Early Cretaceous shales, though to be similar to the source rocks of the Prudhoe Bay field. Coal containing younger Cretaceous strata occurs above the shales. North of the Barrow arch a thick sequence of bedded rocks thought to range from Cretaceous through Tertiary in age dip nothward to the continental slope. Several large diapir folds 37/ occur in the sequence, some pierce the entire section up to the sea floor. 38/

34/ Wilson, Howard M. Alaska: Will It Ever Live Up to Its Potential? Oil and Gas Jounal, Dec. 8, 1980. p. 38.

35/ Neel, T. H. Both Onshore and Offshore Alaska Hold Vast Exploration Potential. Oil and Gas Journal, June 27, 1977, p. 199.

36/ Dolton, G. L., et al., op. cit.

37/ A dome shaped fold, the overlying rocks of which have been ruptured by the squeezing out of the plastic core material (usually salt or shale).

38/ Riva, Joseph P., and James E. Mielke. Polar Energy Resources Potential. A Report Prepared for the Subcommittee on Energy Research, Development and Demonstration and the Subcommittee on Energy Research, Development and Demonstration (Fossil Fuels) of the House Committee on Science and Technology. U.S. Govt. Print. Off., Sept. 1976, p. 73.

The U.S. Geological Survey has estimated that from 0 to 22.6 tcf (with a statistical mean of 4.5 tcf) of undiscovered recoverable gas may exist beneath the North Chukchi Sea. The Survey estimate for the Central Chukchi is somewhat lower, 0 to 15.3 tcf (with a statistical mean of 3.0 tcf). 39/ However, the quantities projected can be considered recoverable only if the technology is developed that will allow production from beneath the Arctic ice pack, which exists in the Chukchi Sea. Such recovery technology is not yet in use. There are no Federal lease sales currently scheduled for either the North or the Central Chukchi basins.

I. ARCTIC SLOPE

The Arctic Slope, also called the North Slope, includes an area in excess of 100,000 square miles, a significant portion of which is considered to have hydrocarbon potential. Oil seeps along the Arctic coast have been reported since the early 1900s and in 1923 some 37,000 square miles of the North Slope were set aside as Naval Petroleum Reserve No. 4, an area currently undergoing Federal exploration for hydrocarbons. 40/ The onshore region includes the Arctic Coastal Plain, the Northern Foothills, the Southern Foothills and the Brooks Range.

The potential hydrocarbon area also extends offshore and includes the continental shelf of the United States under the Beaufort Sea. Water depths over much of this shelf are less than 200 feet. However, the western Beaufort Sea

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39/ Dolton, G. L., et al., op. cit., p. 8, 9.

40/ Gryc, George. Summary of Potential Petroleum Resources of Region 1 (Alaska and Hawaii)--Alaska. Future Petroleum Provinces of the United States--Their Geology and Potential. Memoir 15, The American Association of Petroleum Geologists, Tulsa, Oklahoma, 1971. p. 62.

is almost completely covered by ice for about 9 months of the year and even during the nominal open season (mid-July to early October) scattered to solid pack ice is sometimes present. 41/ The winter ice canopy can be divided into three types: floating and bottom-fast ice of the inner shelf; a brecciated shear zone of grounded ice ridges, marking the area of interaction between the stationary fast ice and the moving polar pack; and the Arctic pack ice of new and multiyear floes, pressure ridges and ice-islands that are in almost constant motion. The general drift of the Beaufort pack ice is westerly. 42/

The average thickness of the sedimentary rocks in the area exceeds 16,000 feet. A southward-thickening Mississippian-to-Jurassic sedimentary section extends between the Barrow arch, near the shoreline, and the Northern Foothills.

The Southern Foothills and the Brooks Range contain thrust plates of Paleozoic and Mesozoic rocks. The older rocks are overlain by organic-rich Lower Cretaceous shales that are thought to have been the source of the hydrocarbons trapped in the super-giant Prudhoe Bay field. Above these shales, younger Cretaceous rocks contain large amounts and coal and some oil and gas. The Beaufort shelf is relatively narrow (30 to 60 miles) and is underlain by a progradational sequence of Cretaceous marine and nonmarine sediments that dip gently north of the Barrow arch. To the east, the Cretaceous rocks are overlain by Tertiary marine and non-marine strata. The geological structure is comprised mostly of large folds. The Cretaceous rocks beneath the Beaufort Sea probably contain organic rich shales at their base as they do onshore. The sandstones higher in the Cretaceous section contain both oil and gas deposits onshore near

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41/ Grantz, Arthur, and David A. Dinter. Constraints of Geological Processes on Western Beaufort Sea Oil Developments. Oil and Gas Journal, May 5, 1980. p. 310.

42/ Ibid.

the coast. It is also possible that some of the pre-Cretaceous rocks, which contain hydrocarbons at Prudhoe Bay, may locally extend across the Barrow Arch and underlie the Beaufort shelf. However, it is not expected that another Prudhoe Bay size field will be discovered offshore in the Beaufort Sea because the larger structures there appear to be complexly faulted, thus limiting the size of the prospective fields and making any hydrocarbons hard to find. The exploration targets in the region will not only be the Permian-Triassic sands, but also Mississippian and Pennsylvanian strata and the younger Cretaceous sands. 43/

During 1968, exploration wells drilled near Prudhoe Bay discovered the largest hydrocarbon accumulation yet found in North America. The field was estimated to contain reserves of about 9.7 billion barrels of liquid hydrocarbons and about 26 tcf of gas. It consists of a succession of stratigraphic accumulations formed on a large structure as a result of the truncation of south and southwest dipping reservoir formations by a Lower Cretaceous unconformity. The main reservoir formation at Prudhoe Bay is the Triassic Sadlerochit sandstone. 44/ The trans-Alaska crude oil pipeline began operations in 1977 and with the help of a drag-reduction additive and the addition of pumping horsepower is now moving crude oil at the optimum Prudhoe Bay production rate, an average of about 1.52 million barrels per day. 45/ Since construction has not as yet begun on a gas pipeline, any produced gas is reinjected into the gas cap over the oil. Plans

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43/ Wilson, Howard M. Wildcatters Poised for the Beaufort Sea. Oil and Gas Journal, June 2, 1975. p. 100.

44/ Brosge, W. P., and I. L. Tailleur. Northern Alaska Petroleum Province. Future Petroleum provinces of the United States--Their Geology and Potential. Memoir 15, The American Association of Petroleum Geologists, Tulsa, Oklahoma, 1971. p. 94.

45/ Alyeska Now Moving Peak Prudhoe Flow. Oil and Gas Journal, Feb. 25, 1980. p. 70.

are also being made to inject seawater beneath the oil in the reservoir to maintain pressure and thus increase ultimate recovery by an estimated 5-9 percent. Prudhoe Bay has already produced over 1 billion barrels of oil, more than 10 percent of its total reserves.

Naval Petroleum Reserve No. 4 was transferred to the Department of the Interior in June 1977. The South Barrow gas field, the oldest actively producing field in Alaska, is located in the reserve. It was discovered in April 1949 as part of an early Navy exploration program. The gas is used for the Naval Arctic Research Laboratory and the village of Barrow. The East Barrow gas field was discovered in 1974 by drilling on a seismic anomaly a few miles east of the older field. 46/ Original recoverable gas reserves in the South Barrow field were 25 billion cubic feet, about half of which have been produced, while the smaller East Barrow field contains an estimated 12 billion cubic feet of recoverable gas. 47/ The fields are of "commercial" size only because the gas is used locally. The Department of Interior has continued the Navy exploration program in the reserve, now renamed the National Petroleum Reserve in Alaska. A 26-well Federal effort has yielded only one potentially commercial discovery. Gas was discovered in the southeast corner of the reserve. The discovery well was not commercial, but it is on a large structure in an area known to contain hydrocarbons. It is immediately adjacent to the Umiat oil field, estimated to contain 70 million barrels of oil, but not yet commercially viable on the North Slope. 48/

46/ Lantz, Robert J. Barrow Gas Fields--N. Slope, Alaska. Oil and Gas Journal, Mar. 30, 1981. p. 197.

47/ Ibid., p. 198.

48/ Gas Find in Alaska Reserve. Department of the Interior News Release. Geological Survey, April 15, 1980.

The Bureau of Land Management is now planning to lease portions of the petroleum reserve to private industry to continue hydrocarbon exploration.

Other prospects on the North Slope include the large Kaparuk field, located some 30 miles west of Prudhoe Bay, with potential oil reserves estimated to be 1.3 billion barrels that may be brought into production as early as 1982. 49/

To the north of Kaparuk a potentially commercial reservoir has been discovered at Milne Point and another potentially commercial discovery has been made east of Milne Point at Gwydyr Bay. Exploration wells in both areas indicate substantial reservoirs, but because of the remoteness of these Arctic locations, additional confirmation wells are necessary to demonstrate commercial size deposits. Other promising areas which may be developed include the Sag Delta, northeast of Prudhoe Bay; and Point Thomson, located about 50 miles east of Prudhoe Bay. 50/, 51/ Exploration wells in these areas have encountered significant amounts of oil or gas.

At a combined Federal-State lease sale in December 1979, high bids of more than $1 billion were made for leases in coastal bays, on barrier islands, and out to the shelf edge of the Beaufort Sea. Permits to drill on the new State leases were not granted until late in 1980. The first wells were drilled near shore in the winter of 1980-1981. Next winter's drilling is expected to provide

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49/ Metheny, Shannon L., Jr. North Slope Field Nearing Production. Oil and Gas Journal, Apr. 13, 1981. p. 129-130.

50/ Wilson, Howard M. North Slope Action Holds West Coast Spotlight. Oil and Gas Journal, May 25, 1981. p. 183.

51/ Exxon Unveils Data on More Alaska Wells. Oil and Gas Journal, Aug. 17, 1981. p. 63.

more general resource information as previously untested prospects under the Beaufort sea will be drilled. 52/

Lying between the Prudhoe Bay region and the discoveries in the Mackenzie River delta of Canada is the 18 million acre National Arctic Wildlife Range. The available geological information indicates that several geologic structures exist in the range. Two are huge, rivaling Prudhoe Bay in size. 53/ Leasing in the range is prohibited by law for at least 5 years, but seismic surveys are permitted. Discoveries of oil and gas on both sides of the range and the existence of the large geological structures, which may indicate potential hydrocarbon traps at depth, are considered to be favorable indications of the existence of hydrocarbon accumulations within the range.

The U.S. Geological Survey considers the Arctic Slope region to be by far the most prospective area in Alaska for hydrocarbon deposits. With Prudhoe Bay (the largest field in North America) already discovered and several other exploration wells showing significant production potential, the Survey has estimated that from 9.4 to 103.1 tcf of natural gas (with a statistical mean of 39.3 tcf) occurs beneath the Beaufort Sea which may be considered recoverable if the technology is developed to allow gas production from beneath the Arctic pack ice; and that from 7 to 84.8 tcf (with a statistical mean of 31.8 tcf) of undiscovered recoverable natural gas exists onshore in the North Slope region. 54/

52/ Operators in Alaskan Beaufort Sea Complete Three Tests, Gear For More. Oil and Gas Journal, April 13, 1981. p. 63.

53/ Moore, J. Cordell. National Arctic Wildlife Range Seen Best Potential For Huge Discovery. Oil and Gas Journal, Aug. 6, 1979. p. 155.

54/ Dolton, G. L., et al., op. cit., p. 8, 9, 11.

J. YUKON-KOYUKUK

The Yukon-Koyukuk area extends south from the Kobuk River to the Yukon River in the area of Koyukuk and Nulato and then continues southwestward to the coastal lowland. It comprises about 100,000 square miles. The region is underlain by predominantly Cretaceous, Mesozoic rocks with exceedingly complex structure. This general structural complexity and the scarcity of favorable reservoir and source beds appear to limit hydrocarbon potential to areas underlain by Cretaceous rocks of shallow marine and nonmarine origin. 55/ A few exploratory wells have been drilled in the area, apparently without success.

The U.S. Geological Survey estimates from 0 to 0.6 tcf (statistical mean 0.1 tcf) of undiscovered recoverable gas for Yukon-Koyukuk basins. 56/

55/ Gryc, George, op. cit., p. 62.

56/ Dolton, G. L., et al., op. cit., p. 11.

APPENDIX III

CRS CONTRACT STUDIES ON ANGTS*

A. Social Cost-Benefit Analysis and Alaskan Natural Gas

B. Natural Gas Pipeline Supply Choice and Industrial User Conversion Costs

C. Public Versus Private Discount Rates in Cost-Benefit Analysis

*CRS does not agree with all substantive aspects of the analysis contained in the following memoranda done by Jensen Associates for the CRS. Nevertheless, these memoranda are reprinted in the appendix because they provide a representative example of thinking in the field by a respected professional consulting firm and provide the interested reader a greater scope of background, opinion and insight in this area.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: **Social Cost-Benefit Analysis and Alaskan Natural Gas**

A social cost-benefit analysis seeks to answer two basic questions: whether a specific project should be undertaken (benefits exceed costs for the project) and which project(s) should be undertaken if investment funds are limited (the combination of projects which produces the maximum net benefit.)[1/] These basic questions are similar to those asked by a private enterprise using standard accounting practices to evaluate its investment opportunities. Private accounting practices, however, are unsuitable for evaluating social projects with respect to their impact on the welfare of society as a whole. The reason is simply that what are costs and benefits to particular individuals within a society are not necessarily counted as costs and benefits to society.[2/]

This shift from a private perspective to a social perspective generates conceptual difficulties in defining and measuring the costs and benefits associated with individual projects. While the market prices for inputs and outputs of projects used in a private analysis are the starting point for social cost-benefit measurement, they prove inadequate where monopoly elements exist in the relevant markets or where volumes are large enough to affect the supply and demand balance for these products. Viewed from a private perspective, a cost-benefit analysis also fails to include all the appropriate impacts of a project on society. For instance, the social costs of pollution are

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1/ Cost-benefit analysis has also been used to determine the level at which plants operate or the combination of outputs it should produce. These uses of cost-benefit analysis are, however, generally ignored in the literature and are not relevant here.

2/ Mishan, E.J., Cost-Benefit Analysis, Praeger, 1976, page x.

not factored into private plant operating decisions beyond the requirements of environmental regulations. Similarly, the social benefits attached to lower energy demands are not reflected in the private decision to conserve fuel.

In the first part of this memo, there is a discussion of some of the basic definitions and measurement principles of social costs and benefits. These comments are not meant to be all-inclusive but rather were chosen to provide a theoretical basis for the discussion of Alaskan (Prudhoe Bay) natural gas which takes place in the second part of the memo. The analysis of this gas supply is itself limited to the social cost at the wellhead plus some additional comments on measuring the net social benefit of marketing this gas.

SOCIAL COST

Within the context of a social cost-benefit analysis, the appropriate concept of costs for a particular project is based on the alternative projects which society does not pursue. Assuming a society's resources are finite, all possible projects cannot be undertaken. To evaluate the social cost of a particular project or policy, a judgment must be made as to which alternatives have been precluded by the selection of this project. Each alternative, in turn, must then be studied to assess the net social benefits which could have been obtained if it had been undertaken. The social cost of the project chosen is the maximum amount of benefits which could have been obtained from among these alternative projects.[3/]

Comparisons of alternatives are not, however, usually conducted on the basis of whole projects, but rather made on the individual resources employed in the various alternate projects. The cost of an individual project, therefore, consists of its "net inputs"--the goods and services withdrawn from the economy that would not have been

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3/ Dasgupta, Partha and Sen, Amartya, "Guidelines for Project Evaluation," United Nations, 1972, page 52.

withdrawn in the absence of the project.[4/] The previous comments regarding evaluation of social costs apply to these net inputs; i.e., the value of these inputs is the maximum benefit they could have produced in some other project. Seen in this light, social costs can best be viewed as opportunity costs.[5/]

In valuing these "net inputs" in terms of their opportunity costs, two cases can be identified. First, an input could be obtained for the project by reducing the amount available to the rest of the economy (the demand margin). Second, the input could be obtained by increasing the overall supply of the input to society (the supply margin). In the latter case, the cost of the particular input stems from the value of the inputs which are used to produce it. The object of this backward step in the analysis aids in determining which resources society is actually being deprived of because of the project under study.

Once the appropriate inputs have been ascertained, valuing them begins with the market price. This is the appropriate price assuming the input and the product for which it is used are sold under competitive conditions, and the additional demand is small relative to the total product.[6/] In the real world, markets seldom meet these conditions and therefore they present all of the usual problems of the second best.[7/] Where the third condition is met, the market price times the number of units needed will provide a measure of the social cost. Where the demand is large relative to the current market, the price will be driven up. In this case, the original market price is too low and the new price too high to be used in measuring the social cost. The appropriate measure of social cost is the old market

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4/ Ibid, page 53.

5/ In Mishan, page 45-74, numerous examples of applying the opportunity cost concept to the social cost evaluation of projects is provided. The comments on unemployed resources are particularly worth reading.

6/ Dasgupta, page 53.

7/ "Deviations anywhere else in the economy from optional pricing and resource allocation principals make it impossible to conclude as a general proposition that application in any single sector of the normative rules...will be desirable." Kahn, A.E., The Economics of Regulation: Volume I, John Wiley & Sons, Inc., 1970, page 195.

price times the quantity plus the consumers' surplus enjoyed by the previous purchasers of the input based on the volume reduction.[8]

SOCIAL COST OF ALASKAN NATURAL GAS

The social cost of Alaskan (Prudhoe Bay) natural gas at the wellhead can be evaluated from two perspectives. The first stems from the basic decision to produce this gas and its social cost in light of the physical relationship to Alaskan crude oil. The second view derives from the value in the various alternatives for disposing of this natural gas after it has been produced.

Prudhoe Bay natural gas is dissolved gas and must be brought to the wellhead in conjunction with crude oil production. Reservoir engineering analysis can determine how much of this gas may be removed and how much must be reinjected to maximuze the total hydrocarbon output from the reservoir. The natural gas discussed in this memo refers only to that amount which can be produced according to this production profile.

Alaskan gas and oil are joint products in the classical meaning of that term. As with any activity, there are social costs and benefits attached to its undertaking--here, the production of the hydrocarbons. The allocation of these costs between the two products cannot be based on economic principles but must be essentially arbitrary.[9] Since production has taken place without any benefits being derived from marketing the gas, the benefits from crude oil production must be sufficient to overcome these joint costs of production.

From a social perspective, we have only two choices with respect to Alaskan natural gas: either produce it or don't produce it. With respect to the decision to produce this gas, the social costs of production can be viewed as sunk costs. These costs have been counted once in the social cost-benefit analysis of oil production and they are not relevant to the gas decision. Society, having made the decision to produce oil, does not have to give up any additional resources to avail itself of natural gas at the wellhead. The "net input" or social cost of natural gas is zero.

8/ This is the standard consumer surplus analysis found in most textbooks. Also in Dasgupta, page 55-56.

9/ Alchain, Arman and Allen, William, "Exchange and Production Theory in Use," Wadsworth Publishing Co., Inc., 1969, page 308.

The alternative of not producing this gas which requires foregoing production of the crude oil as well is not a rational alternative. While non-production would, of course, use no resources or factors of production and therefore have a zero social cost, it would also deprive society of the net benefits currently being obtained from the crude oil production. As an alternative to production, non-production, rather than have a net benefit as our earlier definition of alternatives implied, would have a net cost.

While Alaskan natural gas has a zero social cost associated with bringing it to the wellhead, its value in any use is a function of its highest value in other feasible alternate uses--the social opportunity cost. Once Alaskan natural gas has been brought to the wellhead, only three alternatives for disposing of it exist. They are flaring, reinjection, and marketing. Because of conservative ethics, the first alternative, flaring, is not acceptable and can be ignored within the context of a social cost-benefit analysis.

The second option, reinjection, is the one currently being utilized. The primary costs associated with this option include reinjection wells and these costs have been estimated at 15¢/mcf.[10/] Gas reinjection as a permanent solution also has some long-run negative effects on the volume of oil which can ultimately be recovered and these costs must also be considered in evaluating this alternative. Among the social benefits derived from this option is the availability of a proven supply of natural gas for use in a future time period. An evaluation of this benefit requires an analysis of the energy supply-demand balance in that future period as well as the appropriate discount rate needed to generate the present value of this future benefit. Because of the uncertainties involved in estimating this future balance, the risk component of this analysis, whether accounted for in the discount rate or the benefit measurement, will be high.

In the final option, marketing, the social cost of the natural gas at the wellhead is dictated by its only feasible alternative, reinjection.

10/ Chemical and Engineering News, "Methanol Primed for Future Energy Role," April 2, 1979, page 29.

Therefore, the costs and benefits described above for the second option would have to be evaluated to determine if any net benefit existed. If we realistically assume a high rate of discount to account for risk as well as time preference, and a reasonably long period of time to have balance restored to the world energy market, the benefits associated with preserving an energy supply will be small. This low level of benefits must be compared with the 15¢/mcf cost of reinjection and the costs associated with the loss of crude oil production. Estimating the latter cost would require an in-depth analysis of the particular reservoir characteristics as well as the costs of drilling additional wells necessitated by higher gas/oil ratios as reinjection continues, a task beyond the scope of this memorandum. Therefore, merely for convenience of argument here, we have assumed that these costs and benefits balance out and a zero cost of gas at the wellhead can be used in estimating the social costs of the marketing option.

The marketing option itself consists of many alternatives, including building a pipeline to an end-use market, conversion to methanol with shipment through the oil pipeline, and liquefaction. Each of these alternatives should be studied and the option generating the maximum net social benefit should be chosen. It is important to point out that the outcome of this comparison will change depending upon when the analysis is conducted. Prices, product supplies, and technology are constantly changing and these changes will have an impact on the optimal choice among the many alternatives.

Such an analysis, however, is way beyond the scope of this memo. Comments are offered on only two points within this analysis: first, the measurement of the social benefit of providing this gas supply to an end-use market; and second, the allocation of the difference between the net social benefit of the marketing alternative chosen and zero social cost of the gas at the wellhead.

The process for measuring the social benefit of Alaskan natural gas in an end-use market is similar to that described for measuring the social costs of the "net inputs". A decision must be made as to whether this natural gas is supplied as a replacement for an existing energy source or if it is supplied in addition to energy currently available in the market.

In the case of replacement, the value of the social benefit would be based on the resources released by not producing the replaced supply. For domestic sources, this might be other gas production facilities or possibly electric generating plant inputs. For replacement of foreign resources, the benefit value would be the positive net effect on the balance of payments.

Where Prudhoe Bay natural gas is marketed in addition to existing supply, the social benefit must be derived from an analysis of the demand curve. If the incremental supply is insufficient to alter the supply/demand balance, then subject to the problems of monopoly elements the market price will be an acceptable measure of the per unit benefit. If the market price changes, then a measure must be taken of the change in the area under the demand curve as described in the earlier analysis of social cost.

Whether Alaskan natural gas serves as a replacement or as a supplement to the U.S. energy supplies, the impact of the additional energy available on the world market provides a social benefit. This benefit comes from the reduced pressure on world crude oil prices and to the extent that any society imports oil that country shares in this social benefit.

Naturally these benefits (the gas supply and the reduced pressure on world crude oil prices) must be combined with other identifiable social benefits and then weighed against the social costs to determine the net benefit to be derived from this alternative.

The combination of this net benefit for any alternative chosen under the marketing option and the zero social cost of Alaskan natural gas at the wellhead raises the question of how the overall net benefit will be distributed to the members of society. The mechanism for distributing this net benefit is the price paid to producers. The higher the price, the greater the share of net benefits captured by the producers. The lower the price, the greater the share of net benefits to the end-user. While society may be concerned with distribution problems, in terms of the purposes of a cost-benefit analysis in choosing between alternative projects the size of the total benefit is critical, not its distribution.[11/] The difference between

[11/] Mishan, page 67.

the social cost and benefits sets a range of prices over which society would be willing to pay producers. Within that range, the social cost-benefit analysis provides no guidance as to what that price should be. In the case of Alaskan natural gas, Congress solved the distributional aspects by setting the price for this gas in the Natural Gas Policy Act.[12/]

12/ Public Law 95-621, 92 Stat. 3368, November 9, 1978.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: Natural Gas Pipeline Supply Choice and
Industrial User Conversion Costs

This memo discusses qualitatively two different topics currently of importance in the natural gas industry. The first subject deals with the question of how gas transmission companies choose among alternative sources of supply. The second topic concerns the views of industrial gas users on conversion costs to alternate fuels in light of uncertainty surrounding natural gas supplies.

PIPELINE SUPPLY CRITERIA

Transmission companies provide a transportation link for natural gas from producing areas to market areas. In this capacity, these companies seek to match the throughput of their pipelines with the varying demand for gas found in the marketplace. Prior to the 1970s, when gas was quite plentiful, the primary problem in matching supplies with demand was seasonal swings in spaceheating loads. Longer range variations in demand could be met through exercise of contract flexibility in rates at which production could be taken from dedicated reserves, or by securing access to additional reserves. During the gas shortage period of the 1970s, gas transmission companies lost both of these means of varying long-term supplies. Gas purchase contracts became more rigid in requirements for rapid rates of take (or reserve depletion) and additional supplies were scarce. Also, during the latter part of the 1970s, certain gas prices rose rapidly relative to competing fuels causing loss of demand through conservation and, in some areas of the U.S., actual switching to other less expensive fuels occurred. Thus gas costs to transmission companies have become more critical today than in prior years when federal regulations kept field prices well below free market levels.

These two criteria--matching supplies with demand and the increasing importance of gas costs--encompass the principal concerns of gas transmission companies when they select sources of gas supply. Other factors such as the geographical location, quality and pressure of the gas, or the capital investment required can be discussed in terms of these two major criteria.

Meeting Forecast Demands

In selecting from alternate gas supply possibilities, natural gas pipelines seek to match supply availability with the market demands which have been forecast for the gas distribution companies and the direct industrial firms which these pipelines serve. This supply/demand balancing has both long- and short-term components. The former relates more to the production profile of gas supplies while the latter refers to the flow flexibility available from these supply sources.

For the long-term matching of supply and demand, a pipeline will typically forecast the volume demanded over a 20-year period as shown in Figure 1. Against this demand, individual supply sources by volume are aggregated. Ideally, one would like to have a complete matching of supply and demand as shown in this figure. To achieve this goal, the pipeline would like to be able to vary over a wide range the take from any individual source. Unfortunately, this is not very realistic.

Today many pipeline companies face a deliverability curve more like that shown in Figure 2. In the near term supplies exceed demand, but beyond a point four or five years out, there is a sharp drop-off such that demand exceeds supply. To some extent this will always be the case as gas reservoirs with high deliverability rates are added to the total reserve base. On the other hand, it shows why pipelines would be willing to pay a premium for gas reserves having a long-term production profile. This is seen in the higher deregulated prices being paid today for some deep gas which characteristically produces at a slow rate over a long period of time. At the same time, it is also an advantage associated with coal gasification and Alaskan gas. Besides providing natural gas over an extended period, this gas will not be available until the drop-off period is reached

Figure 1

PROJECTED GAS SUPPLY AND DEMAND

FOR A GAS PIPE LINE COMPANY

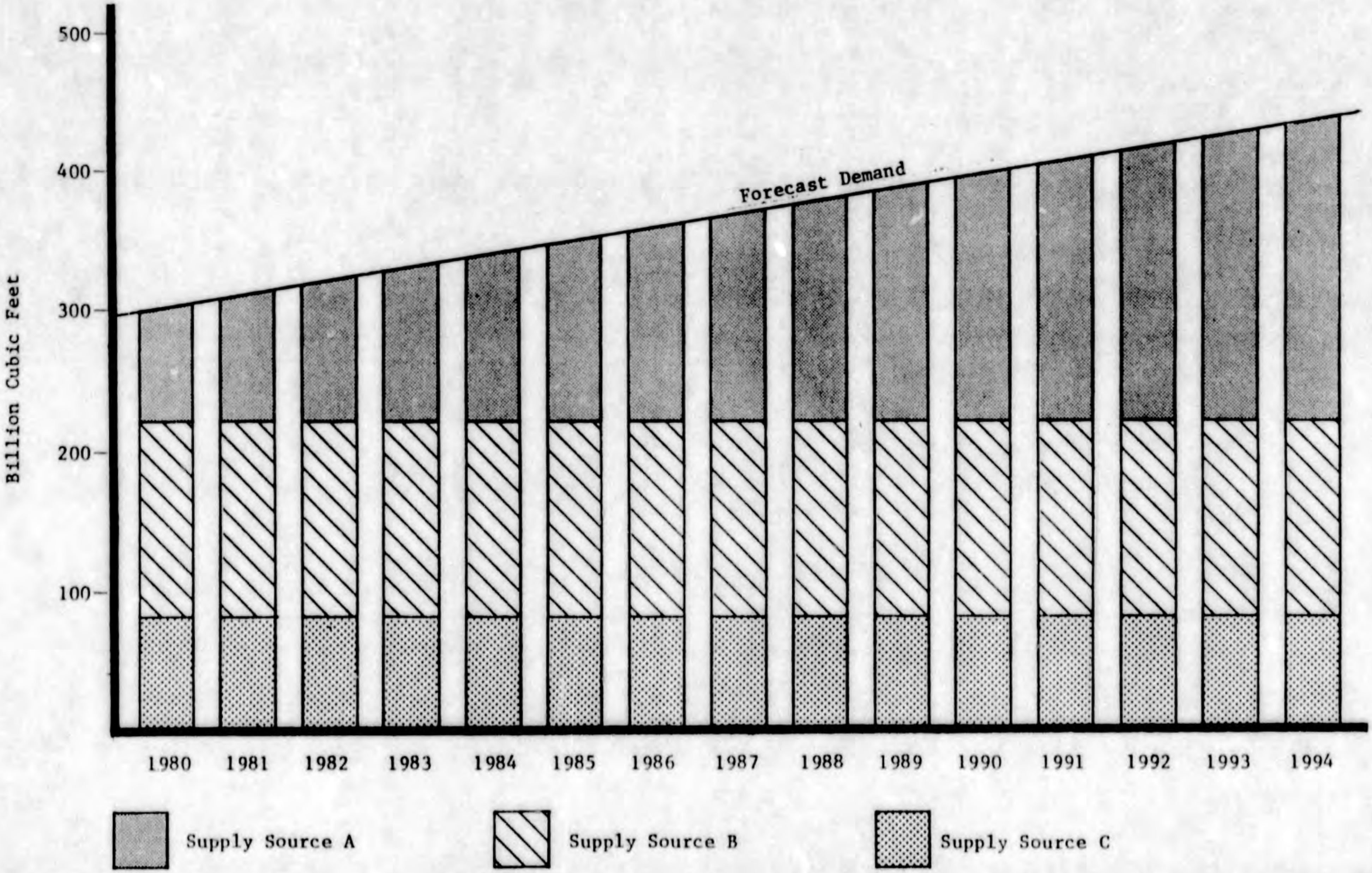
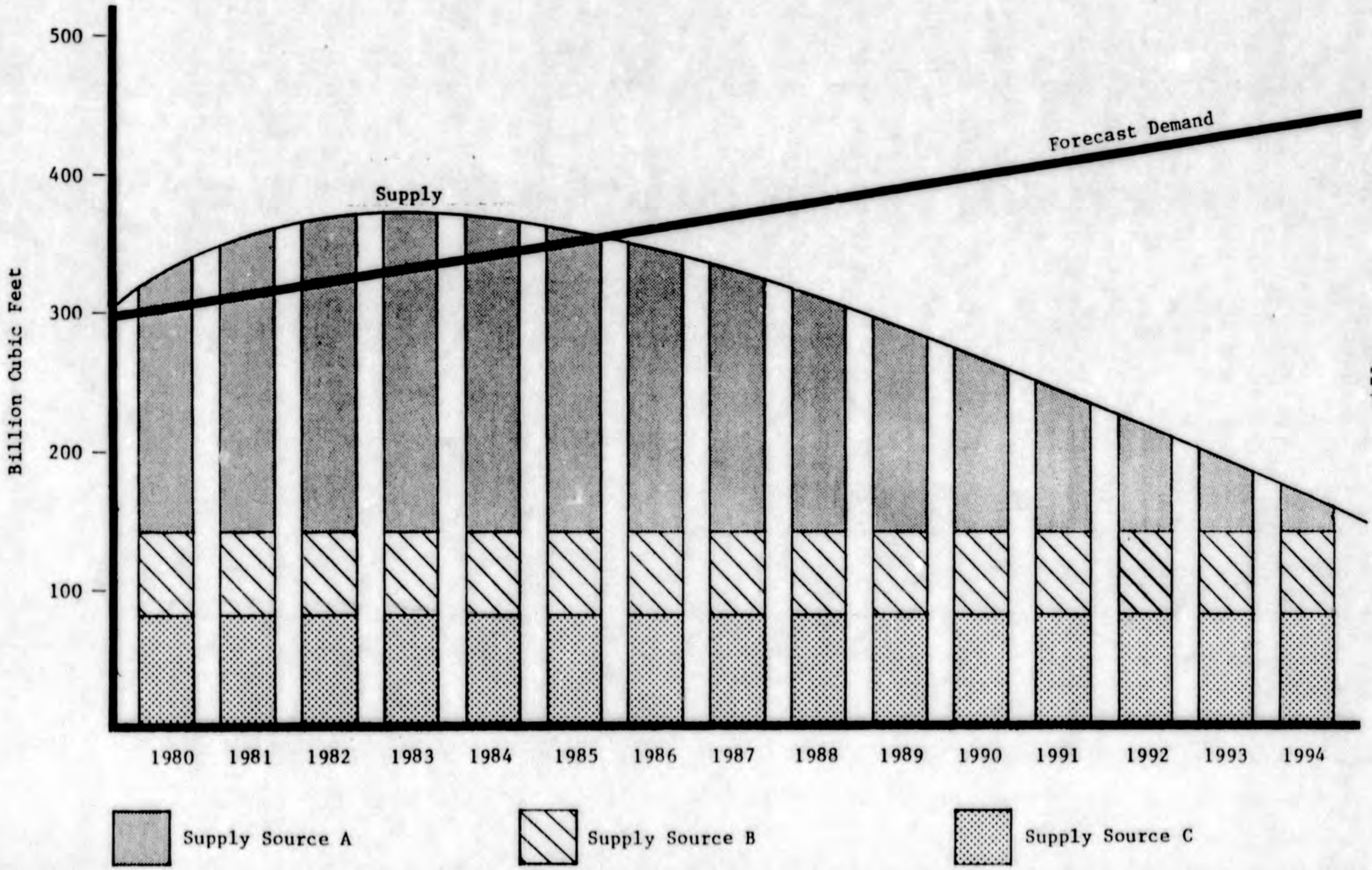


Figure 2

PROJECTED GAS SUPPLY AND DEMAND

FOR A GAS PIPE LINE COMPANY



by most pipelines. In terms of the long-term matching of supply and demand, these projects exhibit two favorable supply characteristics--the long-term constant rate production profile and the delayed production start-up date.

The reliability of these long-term supplies must also be considered in matching demand forecasts. Both physical and political disruptions to supply sources represent possible drawbacks to otherwise acceptable solutions to this long-term need. The recent cut-off in Algerian LNG trade is a prime example of source which adds a constant supply volume over an extended period of time but which has a reliability disadvantage.

For the short-term, flexibility in production becomes a very important factor in choosing among gas supplies. Pipelines experience supply and demand excesses in the long-run pattern because either the production profiles of the types of supplies available do not match their specific needs or because of economic and seasonal demand fluctuations. To meet these changes in the short-term demand and supply balance, pipelines would like to have the ability to vary the volume of gas received from their supply sources.

In the past, a pipeline could meet this need by availing itself of the variations in production rates allowed by individual gas supply contracts. During the 1950s and 1960s, take-or-pay provisions in most contracts permitted the pipeline to take as little as 60-70 percent of the deliverable volume from a gas well with approximately five years allowed in which to make up lesser takes. In this way, the pipeline could reduce its take in periods of low demand and use the excess supply in later periods of high demand thus providing flexibility to its supply position.

The take-or-pay provisions of the 1970s, however, have differed from earlier contracts in that the typical pay level has been set at 90 percent of deliverability or higher. This has narrowed the range that the pipeline has for matching supply and demand. If it takes less than 90 percent for any significant period of time, the ten percent margin available in later periods makes it difficult to make up these volumes. If the reservoir is of a rapid decline type, the reduced deliverability at a later date aggravates this problem.

Some additional flexibility can be achieved if the pipeline owns the gas prior to delivery to the pipeline. This may come about through ownership of gas in storage facilities, in producing fields, or by ownership of synthetic gas production facilities. The value of this ownership derives from controlling the flow of gas when other sources cannot be modulated. The pipeline may face lower total costs by increasing its flexibility in this manner.

Increasing Importance of Field Price and Other Pipeline Costs

Among the considerations of pipeline purchasers when selecting a source of gas supply, the cost of the gas plays an important role. Of course, cost has always been a central consideration. But a number of changes in energy markets during the past decade have focused the attention of purchasers even more upon the cost question.

One such change has been the gradual decontrol of wellhead prices of natural gas. From the mid-1950s until the Natural Gas Policy Act of 1978, the wellhead ceiling prices of natural gas sold to interstate pipelines were established by the Federal Power Commission (F.P.C.). Pipelines were not free to bid for new supplies of gas by offering to pay prices above these established ceilings. Although pipelines became deeply involved in F.P.C. price-setting proceedings, individual pipelines (and individual producers) generally had little influence over interstate wellhead prices. Under such a regime, with prices essentially the same for all sources within any given region, it is understandable that the field price was not the primary cost consideration of pipelines seeking gas supplies. To a certain extent, rate-of-take became a proxy for higher price, with pipelines offering to accept faster rates of production (and hence faster payback periods) to producers as an inducement to commit reserves to interstate sale. Pipelines also offered producers other cost-absorbing inducements such as building production facilities or assuming gas conditioning obligations.

As natural gas prices are decontrolled, individual gas supplies are being offered to interstate pipelines at different prices. Producers having reserves located near an existing pipeline or near a market will be capable of obtaining higher prices as they capture some of the transportation cost savings inherent in their location. Producers will presumably ask higher prices for long-term gas supplies (that is, supplies sold under a contract specifying a lower minimum daily quantity or a lower take-or-pay level) than for shorter term supplies. Thus, pipelines comparing alternative incremental gas supply contracts must look more carefully at the field price as an element of total cost in the comparison process.

Another major change which has occurred in energy markets and which has focused pipeline attention upon gas cost is the tremendous increase in all energy costs to end users since 1973. This increase has made all end users sensitive to absolute and relative energy costs. Significant conservation in the use of energy has been achieved as a consequence, and more may be anticipated as energy prices continue to rise.

Natural gas prices to end users have been a part of this general rise in energy prices, not only as a consequence of the gradual decontrol of wellhead prices but, even before 1978, as a result of higher ceilings set by the F.P.C. Interstate pipelines, as a group, have gone from a situation of chronic undersupply (inability to meet their commitments to local distributors and end users) to a situation in which it is difficult to sell additional volumes of gas into some end-use markets. (To be sure, the present oversupply situation is also a consequence of the current slowdown in economic activity.) The pipeline purchaser, recognizing that its ultimate markets for natural gas are increasingly price sensitive, must be equally price sensitive when acquiring new supplies, which again focuses his attention on the cost element in choosing among alternative sources of gas.

The increasing importance of cost in gas acquisition decisions is accentuated by another important change which has taken place in energy markets in recent years. Not only have energy prices risen substantially, but the degree of uncertainty about future energy prices (and availability) has also increased. This means that even if a pipeline acquires a long-term gas supply at what seems to be an acceptable cost (including escalation over the life of the contract), future events could render that gas too costly for resale without a loss. The inherent uncertainty in energy prices, due to the important role of diplomatic, political and military factors in affecting those prices, forces the risk averse pipeline purchaser to seek lower cost gas supplies and, if possible, gas supplies with limited price escalation potential.

Other aspects of the cost of acquiring natural gas have also taken on increased significance as a result of these changes in energy markets and the variability of field prices for natural gas. For gas acquired through the pipeline's own production rather than through purchase from a producer, greater attention must be paid to lease acquisition, exploration, development and production costs. For purchased gas, the traditional price adjustment for differing Btu content is given closer scrutiny. Also, the potential cost consequences of interruptions in supply from some sources (such as imported LNG) are given increased consideration. While these cost-related elements have always been important in pipeline gas supply decisions, not so much was at stake when gas prices were controlled at levels well below market clearing levels. Under these conditions, additional gas acquisition costs could be passed on to the consumer with a minimal loss in sales volume due to the higher price of alternate fuels. As natural gas markets approach deregulation and thus price parity with these other fuels, even small differences in the gas acquisition costs could have a significant effect on the volume of gas sales to end users.

UNCERTAIN GAS SUPPLIES AND INDUSTRIAL DEMAND

In this section of the memo, the question of how industrial gas users look at conversion costs to alternate fuels when gas supplies are uncertain is discussed.

The conversion costs faced by industrial users can be divided into annual operating costs and capital investment costs. These two costs can be further divided into fuel related and process related costs. Each alternate fuel (oil, coal, electricity, etc.) imposes at least the fuel cost differential as a fuel-related operating cost. To varying degrees, these alternate fuels also impose fuel-related investment costs. Coal, for instance, requires additional investment in space for stockpiling; oil in tank facilities. If the production process employed by the industry is altered by the choice of fuel used, then additional operating costs and investments will be incurred in producing the previous output.

The existence and relative importance of these four cost categories varies substantially between industries. It would, therefore, be impossible to generalize about the specific conditions which would make fuel switching profitable. However, this variation does generate a curve of increasing conversions as conditions of supply and price deteriorate in the natural gas market. Based on past experience, boiler fuel users and other buyers of gas for its Btu content will be the first to shift because they face only the fuel related costs, including both capital and operating components. Economies of scale will, in turn, provide greater conversion incentives to larger users under equal price conditions.

During the period of the 1970s, industrial users were faced with uncertain gas supplies and often total loss of supply through curtailments. In these latter cases where alternate energy sources were necessary, industrial users appear to have made short-range decisions based upon consideration of several factors. The relative as-burned cost of the Btu's utilized, the relative simplicity of facility conversion, and the retained flexibility to utilize other fuels were the most influential of these factors.

Past studies have shown that the majority of these conversions were to oil. Normally oil burning facilities can be designed to utilize gaseous fuels with little additional investment and with simple fuel switching procedures. The higher purchase price of oil and its potential supply disruptions typically were not enough to justify the more costly and time consuming conversions to coal or electricity.

For the future, continued uncertainty with respect to availability of natural gas will have several effects. First, industrial users with dual burning capability will maintain this equipment at a higher level of readiness. Second, some gas load loss may occur as industrial plants seek to preserve a position with the fuel oil distributors. Third, over the long-term industrial efforts will be expended seeking a lower-cost, more secure source of energy.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: Public versus Private Discount Rates in Cost-Benefit Analysis

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Typically, managers in both the public and private sectors of the economy evaluate investment options based on the expected returns over time. The present value technique of discounting future costs and benefits has been accepted as a suitable method of performing these project evaluations. In utilizing the present value technique, the choice of the discount rate to be employed will have a critical impact on the outcome of the evaluation[1/]; and, therefore, great care must be taken in the selection of the appropriate rate of discount.

This paper assumes the reader understands the basic objectives of the present value technique and how it works. The purpose of this paper is limited to a discussion of the differences between the social and private rates of discount. As a basis for this comparison, a definition of the private rate of discount is developed and then followed by a similar effort for the social rate. In a subsequent section, the comparison of these rates is carried out. The final section of this paper provides some very rough numerical estimates of current rates.

1/ A study by Fox and Herfindahl found that of federal projects approved at the rate authorized by Congress in 1962, 2.63 percent, only 20 percent of the projects would have been acceptable at an 8 percent discount rate and only 36 percent at a 6 percent discount rate. Irving K. Fox and Orris C. Herfindahl, "Attainment of Efficiency in Satisfying Demands for Water Resources," American Economic Review, Vol. 54, no. 2 (May 1964), page 198.

More recently the choice of the social discount rate became the subject of debate between President Carter and Congress over the deletion of 19 water resource projects in the 1978 U.S. Budget. The President used a 6.38 percent rate of discount to show that these projects had a benefit to cost ratio less than unity. Several Congressmen argued that this rate was higher than the law allowed and the projects should be approved. Raymond F. Mikesell, "The Rate of Discount for Evaluating Public Projects," American Enterprise Institute, Washington, D.C., 1977, page 5.

A. THE PRIVATE FIRM'S DISCOUNT RATE

For the private firm, the appropriate rate of discount to employ in analyzing investment decisions by the present value technique is the firm's cost of capital. The intuitive logic of this approach can be seen from the following simplified example. Assume that all investments are debt financed and the market rate of interest is 10 percent, which also then becomes the firm's cost of capital. Under these circumstances, using the 10 percent cost of capital figure in the present value formula the firm will accept all projects for which the return is at least $111 a year from now if the costs are $100 today and reject those projects for which the return is $109 or less.[2/] Employing a discount rate higher or lower than the cost of capital would deny the conventional assumptions of economic rationality.[3/]

In practice measuring a firm's cost of capital entails a substantial amount of judgment. While the required payments to the current debt portion of total capital are explicitly stated in contractual terms, the costs of existing equity capital cannot be directly observed. Estimates of the equity cost component are the subject of testimony by financial experts in every utility rate case before Federal and state regulatory bodies. The sheer number of these consultants and the number of different theories employed by them--comparable earnings, discounted cash flow, and capital asset pricing models to name but a few--means that the cost of capital employed in the present value formula is at best an approximation.

Assuming that a reasonable estimate of the firm's current cost of capital can be made, this rate would be an appropriate discount factor

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2/ Partha Dasgupta and Amartya Sen, "Guidelines for Project Evaluation," United Nations, 1972, page 18-19.

3/ If the firm chooses a discount rate of 20 percent, it would reject a project which returned $115 a year from now even though it could borrow the $100 costs today and repay only $110 a year from now thus gaining $5. Similarly, if the firm chooses a rate of 8 percent, it would accept a project which returned only $109 a year from now even though it would have to repay $110 for the investment of $100 today, and thus lose $1.

only if the risks associated with the new project are identical to the firm's existing level of risk.[4/] Since the firm's current cost rate for debt and equity capital were determined by the present level and share of risks borne by the individual suppliers of capital, a change in risk will necessitate a change in the cost rates from the capital sources. For example, if a new project to be undertaken will be more heavily debt financed than the existing capital structures of the firm, then the equity holder's risk will have increased and his demand for additional compensation will tend to raise the total cost of capital, while the lower cost of debt capital relative to equity will tend to lower the total cost of capital.[5/]

An analyst for a private firm wishing to use the present value formula needs to determine the company's cost of capital to find the appropriate rate of discount. Unfortunately, no procedure for measuring the theoretically correct "cost of capital" has been universally agreed upon by the experts.

B. THE SOCIAL DISCOUNT RATE

Selection of an appropriate rate of discount for project evaluation by public investment managers would be a difficult task even if there was a universally accepted definition of the social discount rate. Unfortunately, economists have advanced many notions of what this definition should be and how it should be applied. Two general theories on how the social discount rate should be derived have dominated the discussion

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4/ Charles W. Haley and Lawrence D. Schall, "The Theory of Financial Decisions," McGraw-Hill, 1979, page 334.

5/ Traditional theory holds that as a company increases its leverage through tax deductible debt borrowing, its cost-of-capital curve will decline until the risk associated with the higher leverage becomes the dominant factor for lenders. Beyond this point, both the debt and equity cost rates will increase. This theory has been disputed by Modigliani and Miller in "The Cost of Capital, Corporate Finance, and the Theory of Investment." The authors concluded that the firm's cost of capital curve was flat. This means that the average cost of capital is independent of a firm's capital structure and equal to the capitalization rate of a total equity stream in its risk class. This point is discussed in Sam R. Goodman, "Techniques of Profitability Analysis," John Wiley and Sons, New York, 1970, page 112.

by public policy participants. They are the social time preference and the opportunity cost approaches.

The social time preference rate for discount is based on the government's estimate of the relative value that citizens collectively assign to current versus future consumption.[6] The problem of determining the appropriate values or weights that society places on consumption in individual years now and in the future can be transformed into the standard present value formula by using current consumption as the unit of value and assuming the marginal utility of consumption over time diminishes.[7] The choice of weights thus becomes a choice of discount rates.

In making this choice of an appropriate discount rate under the social time preference theory, advocates of this position look at bond market data in general and the government bond rate in particular. However, the rates in this market reflect the collective preferences for individually

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6/ P. D. Henderson, "Investment Criteria for Public Enterprises," in Public Enterprise edited by R. Turvey, Penguin Books Ltd., Middlesex, England, 1968, page 97.

7/ Looking at the single objective of aggregate consumption, and denoting the net aggregate-consumption effect (benefits minus costs) in year t by Bt, the overall aggregate-consumption benefit B* would be

$$B^* = B_0 + B_1 + \ . \ . \ . + B_t$$

for a project whose useful life is t years. If we make present consumption the unit of account this equation becomes

$$B^* = B_0 + V_1 \, B_1 + \ . \ . \ . + V_t B_t \quad .$$

where V_1, . . . , Vt decline over time to reflect the diminishing marginal utility of consumption. The weights in this formula are such that a decline of $1 in Bo can be offset by an increase of V_1B_1 or of VtBt. If Vt = 0.5 than Bt would have to increase by $2 to compensate for the charge of $1 in Bo. If we make the simplifying assumption that these weights, V_1, . . . Vt, decline at a constant percentage over time, simple algebra can transform this formula into the standard present value formula where i, the social discount rate, equals

$$i = \frac{V_t - V_{t+1}}{V_{t+1}}$$

the rate of change in weights. See discussion in Dasgupta, page 154-156.

accumulated capital, not the individual preferences for collectively accumulated capital.8/ Each individual may be willing to sacrifice more than he would in his private capacity, and to place a lower premium on current versus future consumption, if he is certain that the sacrifice will be shared collectively by the community.9/ Thus, in this case the social discount rate would be lower than these market rates of interest.

An alternative basis for defining the social discount rate utilizes the opportunity cost to society of undertaking a particular project. This cost is equal to the value to society of the use to which the resources employed in this project would have been put in the absence of this investment.10/ In developing this approach, it has been argued that any public investment project must be regarded as displacing an equal amount of private investment.11/ This is essentially a long-run view where the individuals in society make a conscious choice between public and private investment. Given this assumption, the appropriate social discount rate is the average opportunity cost of capital in the private market. Use of a rate higher or lower than this private investment rate of return will make society worse off in an economic efficiency sense.12/

Relaxing the long-run assumption of an equivalent replacement of private investment, allows the more realistic situation where government funds come from more than just the private capital market. Through its taxing powers, the government in practice obtains investment funds by reducing personal consumption, personal saving, government current expenditure, etc. The opportunity cost approach can be adjusted to account for these different sources

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8/ Peter G. Sassone and William A. Schaffer, "Cost-Benefit Analysis, A Handbook," Academic Press, New York, 1978, page 109.

9/ Henderson, page 98.
Sassone, page 105-111. The authors provide two bases for this argument; one in terms of utility theory and one in terms of game theory.

10/ Henderson, page 103.

11/ Jack Hirshleifer, James C. DeHaven, and Jerome W. Milliman, "Water Supply," University of Chicago Press, 1960, page 173.

12/ Lee G. Anderson and Russell F. Settle, "Budget-Cost Analysis: A Practical Guide," Lexington Books, 1977, page 85-87. The argument is similar to that in footnote 3.

of funds by developing an average weighted rate based on the individual cost rates.[13/]

C. PUBLIC VERSUS PRIVATE DISCOUNT RATES

Differences between the social and the private rates of discount can be shown to exist on the basis of the preceding definitional discussion. If the time preference theory for social discounting is accepted as the proper foundation for determining the appropriate rate, then the market rate of interest or capital cost will be higher than the social rate. The market rate of interest does not reflect the collective sacrifice of current versus future consumption obtainable for investment in public projects; but rather reflects only the individual willingness to make such sacrifices.

Under the opportunity cost approach to choosing a social discount rate, the utilization of realized private rates of return builds into the interest rate measurement an average allowance for risk present in the private sector. Use of this rate implies that public investments have risk characteristics similar to those prevalent among private firms.[14/] However, in the absence of the threat of bankruptcy, the government cannot reasonably be expected to have risks comparable to an individual firm within the private sector.[15/] Therefore, we would expect the social discount rate to be different from that of a private firm undertaking the same investment and probably the social rate would be lower.

D. ESTIMATES OF CURRENT DISCOUNT RATES

The scope of our contract does not permit the extensive efforts which would be required to develop estimates of the proper discount rates to be

13/ Anderson, page 88.

14/ Subcommittee on Economy in Government, Joint Economic Committee, "Economic Analysis of Public Investment Decisions: Interest Rate Policy and Discounting Analysis," Washington, D.C., 1968, page 14.

15/ It has been argued that for those projects which have no counterpart in the private sector, the opportunity cost to society should be used for the discount rate. Where there are equivalent private projects, the opportunity cost of capital to these private firms should be used. Ibid page 15.

used for evaluations of either the public or private investment in the alternative gas streams under consideration. The following comments are intended only as a rough approximation as to what appropriate rates may be.

For the social discount rate, the Federal government prescribes two rates depending upon the type of project undertaken. Water resource projects are discounted by a rate which is related to the average cost of Federal borrowing.[16/] This rate currently stands at 7.375 percent.[17/] For the majority of investment projects undertaken by the Federal government, the Office of Management and Budget has dictated a 10 percent rate. This rate is judged to be an estimate of the average rate of return on private investment, before taxes and after inflation.[18/]

In the private sector, determining the appropriate rate of discount requires estimating the opportunity cost of capital to the firm planning to undertake the investment project. A reasonable approximation to this rate can be made by taking the allowed rate of return on equity in recent natural gas pipeline cases and combining it with the prime rate to yield an average cost of capital. As of this writing, the prime rate was 20 percent and the equity return allowed was 14 percent.[19/] Using a debt to equity ratio of 41 percent to 59 percent and an effective tax rate of 44 percent,

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16/ "Standards for Planning Water and Related Land Resources," "Water Resources Council and Related Land Resources," Federal Register, Vol. 39, 1974, page 29242.

17 Federal Register, Vol. 45, 1980, page 70167.

18/ Office of Management and Budget, "Discount rates to be used in evaluating time-distributed costs and benefits," Circular-A-94, March 27, 1972, page 4.

19/ Prime Rate = 20 percent. Wall Street Journal, September 18, 1981, page 41.

Equity Return = 14 percent. United Gas Pipe Line, F.E.R.C. Order No. 99, October 10, 1980. Transcontinental Gas Pipeline, F.E.R.C, Order No. 59, August 30, 1980.

this translates into a pretax return of 23 percent.[20/] Assuming an inflation rate of 8 percent, this would be equivalent to a real discount rate of 15 percent. The measurement of the cost of capital is sensitive to the debt/equity ratio and tax rate chosen. If we were to use the debt/equity ratio of 75 percent to 25 percent discussed for ANGTS, the private discount rate or cost of capital would be 21 percent,[21/] or a real rate of 13 percent. Determining the appropriate private discount rate thus depends on the capital prospects of the private firm which in fact would undertake the investment.

20/ American Gas Association, Gas Facts 1978, Tables 133 and 139, data for Transmission Companies, pages 160 and 169.

$$\begin{aligned}
\text{Cost of Debt} &= 20\% \times .41 &&= 8.2 \\
\text{Cost of Equity} &= 14\% \times .59 \times \frac{1}{1 - .44} &&= \underline{14.7} \\
\text{Cost of Capital} &= &&= 22.9
\end{aligned}$$

where effective tax rate = .44.

21/ "Determination of Incentive Rate of Return, Tariff, and Related Issues," (ANGTS), F.E.R.C., Order No. 31, June 8, 1979, page 64.

$$\begin{aligned}
\text{Cost of Debt} &= 20\% \times .75 &&= 15.0 \\
\text{Cost of Equity} &= 14\% \times .25 \times \frac{1}{1 - .44} &&= \underline{6.2} \\
\text{Cost of Capital} &= && 21.2
\end{aligned}$$

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

MEMORANDUM State of Alaska

TO: John W. Katz
Commissioner

Jeff Haynes
Deputy Commissioner

FROM: Mary Halloran MH
Special Assistant
to the Commissioner
Natural Resources

DATE: November 30, 1981

FILE NO:

TELEPHONE NO:

SUBJECT: Gas Pipeline Financing

To facilitate your review of the massive amounts of information related to the Alaska Natural Gas Transportation System (ANGTS) and its financing, this memorandum summarizes the major points of the basic documents related to the project's financing. I was aided in this work by Robert Loeffler who provided a chronological list of most of the basic materials and copies of the materials themselves.

I. President's Decision and Report to Congress on the Alaska Natural Gas Transportation System.

The ANGTS enabling decision by President Carter in September, 1977, contains specific terms and conditions for financing of the project. Among those terms are the following:

1. Northwest Alaskan Pipeline Company, then known as Alcan, shall provide for private financing of the project, and shall make final arrangement for all debt and equity financing prior to initiation of construction.

2. The Federal Power Commission (later became the Federal Energy Regulatory Commission, or FERC) shall set a variable rate of return on equity to reward project completion under estimated budgeted cost and to penalize cost overruns.

3. Neither the project sponsor nor any purchaser of Alaska gas shall be allowed to use any tariff which would compel the purchaser or ultimate Prudhoe Bay gas consumer to pay a fee or payment prior to completion and commissioning of operation of the pipeline system.

4. The Alcan Pipeline Company or its successor is not open to ownership participation by producers of Alaska natural gas.

Another important provision of the Decision was to prohibit any project ownership by Alaska gas producers, except provision of guarantees for project debt. The prohibition covered producers' having equity membership in the sponsoring consortium, voting power in the project, any role in management or operations of the project, and any continuing financial obligation which might impose anti-competitive conditions on project debt.

In the section of the Decision (pp. 50-66) dealing with the agreement on principles vis-a-vis financing between the U.S. and the Canadian governments, the understanding that pipeline construction will be privately financed was reiterated. In addition, provisions were made regarding non-discriminatory tax treatment of the pipeline by the Provinces of British Columbia, Alberta and Saskatchewan and by the Yukon Territory. Note was made, however, that should the State of Alaska require creation of a special fund or funds (for socioeconomic costs) not fully reimbursable in connection with pipeline construction in Alaska, that the Governments of Canada or the Yukon Territory will have the right to take similar action.

The President's Decision also contained an analysis of pipeline financing (pp. 100-127) which concludes that the project can be privately financed (supporting, not surprisingly, the condition of the Decision that the project is required to be privately financed). It boldly concludes, "Novel regulatory schemes to shift this project's risks from the private sector to consumers are found to be neither necessary nor desirable. Federal financing assistance is also found to be neither necessary or desirable, and any such approach is herewith explicitly rejected."

At that time the project was already labeled the "largest privately financed energy project ever undertaken" with a price tag of $10 to $15 billion. Therefore, the authors of the Decision proposed a plan to balance project benefits and risks which had four main provisions:

1. Equity investment would be at risk under all circumstances, and budgeted equity investment would be considered the first funds spent. The rate of return on equity would compensate sponsors for bearing this risk.

2. Producers and the State of Alaska, as direct and major beneficiaries, should participate in pipeline financing either directly or in the form of debt guarantees.

3. Cost overruns would be shared by equity holders and consumers through use of a variable rate of return on common equity.

4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences.

The authors of the Decision determined that pipeline financing would be successful without consumer noncompletion agreements, reasoning in part that there was sufficient credit support capacity among the direct beneficiaries to assure pipeline completion without assistance from consumers. They counted among those beneficiaries the gas transmission companies, gas producers, and the State of Alaska.

"The benefits of these parties sufficiently outweigh the risks associated with the project so that it is reasonable to expect them to provide support at small additional cost to consumers" (p. 102).

Another unique aspect of the proposed financing plan was that Alcan, now Northwest Alaskan, proposed to raise capital through "project financing" rather than the more traditional "balance sheet financing" normally used in the gas pipeline industry. Revenues from the project itself were expected to pay for its operating costs, interest and principal on debt, and a return on, and ultimately a return of, equity to its investors. (Equity was later set at 25% of project cost, and debt at 75%(.

The Decision found the project demonstrated basic economic soundness: "Even under extreme cost overruns, the delivered cost of Alaska gas will be economically attractive" (p. 105). Delivery of Alaskan gas was assumed to begin January 1, 1983, at a cost of $10.3 billion. Projected sources for the funds were U.S. and Canadian banks, U.S. and Canadian long-term debt, and U.S. and Canadian common stock. The authors of the Decision reasoned that as the total assets of the gas transmission industry at the end of 1976 were only $26 billion, the "project must be seen as a corporate entity in itself, capable of issuing and servicing its own debt and equity" (p. 108). They also concluded that at that time the investment's importance in terms of the total capital markets was "modest." Equity was to come from the gas transmission or distribution companies, with debt from the capital markets mentioned earlier.

The Decision suggested that cost overrun financing, an issue from the inception of the project, could be resolved by enlarging the sponsor group to include as participants in financing the gas producers (Exxon, Arco and Sohio) and the State of Alaska.

Producer participation in financing was called for due to their beneficiary status and their financial strength. Similarly the State of Alaska was singled out as a possible financial participant due to its resultant revenues from project success (royalties, severance taxes, and property taxes), and the benefits of use of natural gas inside the State. Never was the contradiction between the Decision's emphasis on private financing and its inclusion of the State of Alaska as a financial participant explained.

The authors of the Decision also chose to interpret an indication of State interest in El Paso (a Northwest competitor) project debt by former Revenue Commissioner Sterling Gallagher (letter of July 19, 1977, from Gallagher to Roger C. Altman, Assistant Secretary, Capital Markets and Debt Management) as a "willingness and ability" of Alaska to guarantee up to $900 million of the El Paso project debt. The implication was that comparable State interest might be found for the Northwest project. (The Decision's authors ignored the caveats expressed explicitly in Gallagher's letter, such as the need to establish a 50 percent contribution level to the Permanent Fund for all oil and gas royalties; the express resolution of the Alaska Legislature to limit study of State participation in financing to the El Paso or all-Alaska route; and the need for legislative approval for implementation of any financing proposal).

The Northwest proposal differed substantially from that of its competitors in that El Paso stated that consumer guarantees through an "all-events" tariff and federal backstopping through federal loan guarantees for LNG tanker fleet financing would be vital. Northwest said no consumer guarantees nor Federal financial assistance would be necessary. Of special interest may be the list of reasons why the authors of the Decision considered federal financial assistance undesirable (see Appendix A: Decision, p. 122). Alaska was assumed by the Decision authors to be among those entities which would bear the entire noncompletion risk, although the major portion of the risk was assumed to be borne by the project sponsors as equity capital investors.

II. Natural Gas Policy Act of 1978

The Natural Gas Policy Act of 1978 embodied three provisions with substantial impacts on the Alaska project. First, it fixes the wellhead price of Prudhoe Bay gas under Sec. 109 at $1.45 per MMBtus as of April 20, 1977, subject to escalation for inflation. Sec. 109, however, leaves open the possibility of later wellhead price adjustment by the Federal Energy Regulatory Commission. Second, it provides that Prudhoe Bay gas will remain regulated after January 1, 1985, when certain other categories of gas are now scheduled for deregulation. Third, the Act allows the rolling-in or averaging of the price of Alaskan gas, including transportation and related costs, with the prices paid by U.S. pipelines for gas from other sources. This provision establishes, in effect, a cushion for higher priced Prudhoe Bay gas, making it seemingly more marketable.

III. Agreement Between Alaskan Northwest Natural Gas and the State of Alaska, April 1978

In April 1978, Governor Jay Hammond and Alaskan Northwest Chairman John McMillian jointly signed a State-Northwest agreement in which Northwest agreed to do several, including the following which bear on state participation in financing and pipeline financing: (1) The Partnership agreed to support before the Federal Energy Regulatory Commission (FERC) gas pricing that (a) "adds on" conditioning costs to the wellhead, (b) defines "old-gas" as only that from the Prudhoe Bay pool, (c) allows rolled-in pricing for Prudhoe Bay gas, and (d) sets a minimum $1.45 mcf price (escalated) for Prudhoe Bay "old" gas. (The Partnership, however, opposed "added on" conditioning costs in the FERC proceedings); (2) The Partnership will pay the State's reasonable expenses to be incurred for financial and related analyses made to evaluate and/or implement the State's plan to participate in financing the project. The Agreement carried no provisions for State actions.

IV. Cooperative Agreement for Design and Engineering of Alaska Gas Pipeline and Conditioning Plant, and Joint Statement of Intention

The next major document with essential implications as to pipeline financing was the June 1980 Cooperative Agreement and the accompanying Joint Statement of Intention of June 19, 1980. The Agreement outlined the terms and conditions under which the Northwest partnership and the Prudhoe Bay gas producers (Exxon, Arco and Sohio) were to participate in the design, engineering, construction planning, data gathering and cost estimating of the gas pipeline and the gas conditioning facilities for the project segment inside Alaska.

Under the terms of the Agreement, the State of Alaska was given a non-voting seat on the Design and Engineering Board which was to govern the expenditures of the group, Also the State could designate a Project Advisor to the group's Technical Committee. The State, however, was not to contribute any capital funds with respect to the work undertaken pursuant to the Agreement, and, accordingly, would not acquire any ownership rights to the design and engineering information developed. Under Sec. 13.7, "Commitments", the State agreed to continue "its study of forms in which it may participate financially in the pipeline, plant or both. The State may elect to pursue its present intention to develop a plan for financing the plant within the time frame of this Agreement." Originally, the Agreement was scheduled to expire July 1, 1981. It has since been amended to provide for its continuation on a quarter-by-quarter basis.

The accompanying Joint Statement of Intention, not signed by the State of Alaska, made clear that the Cooperative Agreement was necessary to "move forward in surmounting the acknowledged difficulties presented by this project" by expediting design, engineering and cost estimation. By January of 1981, the Design and Engineering Board had authorized over $90 million in expenditures.

V. Alaskan Northwest's May 21, 1981, Letter to Secretary Edwards and Associated Materials Describing the Conceptual Approach Underlying the ANGTS Financing Plan.

Approximately a year after work on design, engineering and cost estimates was initiated under the direction of the Design and Engineering Board, the Northwest partnership presented an ANGTS financing concepts plan for the Alaska segment to Energy Secretary Edwards and others. The concepts included the following:

1. The "as spent" cost of the Alaskan pipeline will be $21 billion, with another $6 billion allocated for the conditioning plant. In addition, a pre-committed completion assurance pool of $3 billion will be formed.

2. Debt/equity ratio remained 75:25.

3. Investment limits were defined as $5.25 billion in equity for the transmission companies; $2.25 billion in equity for the gas producers; and with responsibility by the producers for arranging debt up to $6.75 billion and responsibility by the transmission companies for arranging debt up to $15.75 billion.

4. Northwest partners will own 70% of the pipeline and plant, and the producers 30%. Equity commitments to the completion assurance pool will be made on the same 70:30 ratio.

5. Debt funds for both pipeline and contioning plant will be sought on a project credit basis.

6. Each company's participation will be subject to satisfaction of certain conditions, including inclusion of the conditioning plant as part of the Alaska segment of ANGTS; limitation of each company's investment to a sum certain defined in the financing plan; issuance of firm commitments by all debt and equity participants, acceptable to all other participants, prior to construction of the pipeline or plant; issurance of all necessary governmental authorizations; assurance to all parties that the project is economically viable; assurance to all parties that the Cnadian segment will be financed and completed without U.S. company involvement; and equal terms and conditions for each financing layer.

The descriptive backup information contained the following argument regarding project economics:
"A key to why the ANGTS represents America's best energy bargain lies in the downward slope of the ANGTS delivered real cost of gas over time. Each year that ANGTS operates it will move gas more economically than the year before. No other energy project can promise a year-by-year reduction in energy cost; but ANGTS will produce this result because of one, fixed constant dollar wellhead prices and, two, transportation costs are a high portion of delivered cost and because of the operation of its FERC-established tariff which requires that transportation costs be reduced annually as depreciation charged to operating cost returns original investment and thus reduces the subsequent years' rate base upon which transportation charges are caluclated" (p. 4).

At this time the Alaska segment was estimated to cost $8.3 billion in 1980 dollars, plus an additional $3.5 billion in 1980 dollars for the conditioning plant. Financing and construction of the two Lower 48 segments, known as the Western U.S. leg and the Eastern U.S. leg, were already underway.

In the discussion of financing in this document, only short mention is made of possible State participation (p. 88): "The President's Decision envisioned participation in the financing of the project by the State of Alaska. Any debt financing provided by the State of Alaska, or other Alaska governmental bodies, would act to reduce the funding required from other sources."

V. Waiver of Law Package

The next major set of documents with financing implications is the waiver of law package introduced by President Ronald Reagan to the U.S. Congress on October 15, 1981. Reagan reiterated his support for completion of the ANGTS project "through private financing." The purpose of the waiver package, according to the President, is "to clear away governmental obstacles to proceeding with private financing of this important project."

If approved by the Congress, the waiver package would accomplish the following: (1) allow producer participation in equity financing provided certain anti-trust issues are appropriately addressed by FERC; (2) clearly include the gas conditioning plant as part of the approved transportation system; (3) provide for the commencement of billing to consumers in advance of system completion and commissioning of operation; (4) eliminate the possible interpretation that the Natural Gas Act requires an evidentiary hearing on each application for a certificate of public convenience and necessity to construct or operate any segment of ANGTS; and (5) limit FERC's ability to change any rules or orders regarding tariffs which might impair recovery of debt service.

VI. Statements of representatives of Bank of America, Morgan Guaranty Trust Company of New York, Citibank, and Chase Manhattan Bank.

During the Congressional hearings on the waiver package, representatives of the four above-mentioned banks testified on the pipeline project. They were requested by Northwest to review the financial concepts plan Northwest proposed (See IV). The testimony of H. Anton Tucher, Vice President, Bank of America was typical. Tucher stated the bank is presently identifying independent consultants to help evaluate marketability of Alaska gas, capital cost estimates and construction programs, and adequacy and deliverability of gas reserves.

The three areas analyzed to date were:

(1) likely availability of debt market funds in amounts commensurate with the project's large size. They found the project's debt requirements "are likely to test the limits of the world's capital markets."

(2) proposed financing structure presented by Northwest. They concluded that the project could be financed only if lenders were assured that creditworthy parties had undertaken to assume or repay the project debt in event of noncompletion of the project by an agreed upon date. "Creditworthy" meant parties with the financial capacity and incentive to assure timely project completion, or failing that, with the financial capacity and obligation to either repay or assume the debt in the event of non-completion.

(3) the waiver package. According to the banks, the three key aspects are producer ownership participation, billing commencement date, and authority to modify or rescind orders. Tucher concluded, "I cannot emphasise enough that without approval of these waivers, private financing for the project is not possible. On the other hand, I cannot tell you that approval of the waivers will assure private financing for the project."

The banks will continue their analyses with investigations into the technical, economic, financial and regulatory feasibility of completing the whole system.

In addition to being unnecessary, Federal financial assistance for this project is considered undesirable for the following reasons:

1. Serious questions of equity result from the transfer of risks to taxpayers, many of whom are not gas consumers or will not receive additional gas supplies as a result of the Alaskan project.
2. Federal financial support substitutes the Government for private lenders in the critical risk assessment function normally performed by private lenders.
3. A subsidy in the form of lower interest rates yields an artificially low price for gas.
4. The incentive for efficient management of the project is reduced.
5. The Government is placed in conflicting roles as guarantor and as regulator of the project.
6. Providing unnecessary Federal assistance to this project would set a precedent with respect to other large energy projects that is misleading and counterproductive.

Variable Rate of Return

Since the tariff will require gas consumers to pay for

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September 12, 1979

ANGTS

gasoline file

MEMORANDUM

RE: FERC Order, August 6, 1979,
-- 1260 PSIG Operating Pressure

A. Introduction

This memorandum will address the question of whether the 1260 psig maximum allowable operating pressure approved by FERC in its August 6, 1978 Decision in Docket No. CP78-123, et al., Alaskan Northwest Natural Gas Transportation Co. -- Pipeline and Capacity (hereinafter FERC opinion) was in effect mandated by the President's Decision 1/ so as to preclude FERC from exercising its independent discretion in deciding this matter. 2/ After a comprehensive review of the Decision and numerous other relevant materials, it is concluded that, notwithstanding comments to the contrary by FERC in its August 6, 1978 opinion, nothing in the President's Decision required FERC to reach its 1260 psig conclusion or suggests a predisposition by the President toward that pressure which would have required FERC to give it more weight than any other one. To the contrary, the Decision expressly indicates that the question of the optimal operating pressure should be a subject of further study and recommendation by a joint U.S. and Canadian technical study group before any decision is made by FERC with respect to this matter.

1/ Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaskan Natural Gas Transportation System (September, 1977). Reference herein to this Decision includes also its accompanying Report.

2/ At page 7 of its opinion, FERC concluded that "absent evidence as to a need for increased capacity, the President's Decision creates a presumption that the operating pressure should be 1260 psig."

A subsequent memorandum from this office will deal with the implications which this disparity between the FERC 1260 psig finding and the President's Decision may have for seeking reconsideration by the FERC of its August 6, 1978 conclusion or for securing a court finding that the FERC Decision in this matter constitutes reversible error.

B. Disparities Between FERC Order And The Decision

In setting the design specifications for the Alaskan segment of the pipeline at a 48-inch diameter size and a 1260 psig maximum allowable operating pressure, FERC stated that the President's Decision --

> . . . decided that the diameter of the pipeline will be 48 inches. Moreover, the Decision creates a predisposition that the 1260 psig system is the one authorized by the President and the Congress, by stating that the "facilities approved and subject to the provisions of ANGTA are those included in the revised Alcan filing submitted to the Federal Power Commisson (FPC) on March 8, 1977. 3/ (Emphasis added.)

The foregoing finding by FERC that the facilities included in the revised Alcan filing of March 8, 1977 were "approved" by the Decision is not accurate. The actual language of the portion of the Decision referred to by FERC reads as follows:

> This section identifies the facilities for the Alcan project which will be entitled to the expedited authorization process prescribed in Section 9 of AGNTA. The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC on March 8, 1977. (Emphasis added.) 4/

3/ FERC Order at 3.

4/ Decision at 13.

As seen, the Decision does not state that the subject facilities are "approved", but merely designates those facilities for the expedited authorization process prescribed by ANGTA. 5/ In this respect, the Decision identifies those facilities adequate for a throughput of 2.3 bcfd and further notes that they are included in the Alcan filing. Further, the emphasis in this portion of the Decision relied upon by FERC is solely on the throughput capacity -- the pressure of the system is not mentioned or identified.

There is substantial discussion of the pressure of the system in other parts of the Decision which was apparently ignored or overlooked by FERC. In this respect, the Decision notes that the Agreement on Principles between the United States and Canada "provides for a jointly conducted testing and evaluation program to determine which system would offer the highest degree of safety, reliability and efficiency. Upon completion of the testing program, the respective regulatory authorities of each country will make a final decision as to which type of system might be installed in each country." 6/

While it is true that much of the discussion in the Decision with respect to the joint study is concerned with the pressure of the pipe to be installed in the Canadian segment, the Decision clearly indicates that this factor was left

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5/ Alaska Natural Gas Act ' 1976.

6/ Report accompanying Decision at 185. The Agreement on Principles between the United States and Canada specifically provided in this respect that --

> "The Governments will establish a technical study group for the purpose of testing and evaluating 54-inch 1120 psi, 48-inch 1260 psi, and 48-inch 1680 psi pipe or any other combination of pressure and diameter which would achieve safety, reliability and economic efficiency for operation of the Pipeline. It is understood that the decision relating to pipeline specifications remains the responsibility of the appropriate regulatory authorities." See Decision at 62.

open with respect to the Alaskan segment as well. Thus, as noted above, the Decision acknowledges that the joint study prescribed by the Agreement on Principles relates to "which type of system might be installed in each country." (Emphasis added.) 7/ The following comments made in the Decision also show that the psig for the Alaska segment was considered to be an open item:

> In addition, if a 1680 system is installed south of Whitehorse, consideration will be given to installation of a 1680 psi system in Alaska, perhaps with a pipe diameter less than 48 inches. The higher pressure system is generally more economically efficient than lower pressure design. (Emphasis added.) 8/
>
> * * * * *
>
> However, if Alcan increases pressure to 1680 psi, either for the Alaska segment of its line alone or for sections in Canada, additional value design evaluation will be necessary. (Emphasis added.) 9/

The foregoing references clearly contradict the conclusion of a predisposition in the Decision for a 1260 psig. If that were the case, the above comments cited from the Decision would be meaningless. Moreover, as seen, the notion that the Decision contains a predisposition toward a 1260 psig would be contrary to the scheme contemplated by the U.S. - Canadian Agreement on Principles which stipulated that this technical matter should be the subject of eval-

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7/ Decision at 185.

8/ Decision at 184.

9/ Decision at 190.

uation and testing by the joint study force to be created pursuant to that Agreement before any final decision is made. In this respect, while the Decision indicated that there was a "likelihood" that a 48-inch 1260 psig line would be installed in Alaska, the final decision regarding this issue was to be made by FERC and its Canadian counterpart on the basis of the study group's findings. 10/

In point of fact, a joint recommendation by the study group was never made. The U.S. representatives recommended a 48-inch 1680 psig pipeline for the Canadian segment while the Canadian representatives advocated a 56-inch 1080 psig system. 11/ Prior thereto the U.S. representatives had re-

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10/ See, Decision, pp. 260-261, which provides as follows:

> Subparagraph (a) establishes a joint technical study group for the purpose of evaluating the relative merits of the larger diameter and higher pressure systems which have been suggested, as well as any other combinations of pressure and pipe size which might achieve objectives of increased effi-
> pp. 260-261.)
> ciency. The 48-inch, 1260 psi which was proposed by the applicant and will likely be installed from Whitehorse north to Prudhoe Bay field will also be evaluated by the group. Final decisions based on the results of the testing program will remain the responsibility of the respective regulatory authorities in the two countries. (Emphasis added.) (Decision, pp. 260-261.)

11/ Notice of Delegate Report and Order Inviting Comments, Docket F78-123, issued May 17, 1979 pp. 2-3.

commended a 48-inch 1680 psig system for the Alaskan segment as well, in view of the possibility of additional reserves. 12/

The fact that the psig was left open by the President's Decision is further seen from its discussion of the potential need to increase the capacity of the line 13/ to accomodate possible additional possible reserves. The FERC decision itself states that this possibility makes what it previously had found to be a Presidential "predisposition" a "rebuttable one." 14/ However, FERC then goes on to make it appear that increased compression is the only means by which the Decision contemplated additional reserves should be handled, implying that an increase in psig was not considered. Thus, the FERC opinion states that --

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12/ Despite Canada's decision the United States Department of transportation continued to recommend the 48-inch 1680 psig system for the Alaskan segment. In the "Report Of The Alaskan Delegate on the System Design Inquiry", the DOT:

> . . . argued that all the technical and economic data appear to them to support building a 1680-psig system. Moreover, the availability of capacity resulting from the construction of 1680 psig system would encourage development and exploration in the total North Slope area. Citing a February, 1978 Tehnical Study Group evaluation of the 1680-psig system, DOT argued the system could be build and operated safely and reliably. Report of the Alaskan Delegate on the System Desig Inquiry, supra, pp. 17-18. (Decision at 193.)

13/ The only other connection in which psig is discussed in the Decision is with respect to capital costs incurred in Canada. Significantly, this discussion cites capital costs for a 48" 1260, as well as a 1680, psig line, in addition to a 54" 1120 psig line. (Decision, p. 77.) It was also noted that the discussion of these Canadian capital costs excluded any increases in costs attributable to a number of factors, including the gas conditioning plant construction. (Decision, p. 79.)

14/ FERC Decision, p. 4.

> The President's Decision also stated that the capacity of the system should be adequate for an average daily throughput of up to 2.4 billion cubic feet per day (Bcfd); and with inreased compression, capable of increasing to an average daily capacity of 3.2 Bcfd." 15/

In fact, increasing psig to 1680 was clearly another alternative mentioned in the Decision for expanding the capacity of the system. For example, the Decision states --

> If a 1680 system is installed . . . . The system would have lower fuel and operating expenses than a 1260 system but the savings would not be quite sufficient to offset carrying charges on the increased capital outlays. On the other hand, the system does provide a large amount of inexpensive expansibility that could be used in the event significant new finds of natural gas are made in Alaska. 16/

Further, the Decision ultimately concludes that additional compression is not a desirable means to provide for the need for future increases in capacity, and that from a cost standpoint the more desireable alternatives are increasing the diameter or working pressure of the pipe.

> It was also suggested in the safety and design report that for economic reasons, Alcan should consider increasing the operating pressure and wall thickness of its 48 inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources.

* * * * *

15/ FERC Order at 4.

16/ Decision at 166.

> Compression requires fuel essentially in proportion to the horsepower added. Thus, as more throughput is required in an existing pipeline, horsepower (capital cost) and fuel use (operating cost) will increase.
>
> (Footnote: Horsepower and fuel requirements increase roughly as the difference between the squares of the relative throughputs. Doubling the throughput would require about 4 times as much fuel.)
>
> * * * * *
>
> . . . Overall, considering the artic construction, inflationary impacts, and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughput would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline. 17/

C. Conclusions

Based upon the foregoing, it is apparent that FERC erred in finding that the Decision contains a predisposition for the 1260 psig for the Alaskan segment. It further appears that this erroneous finding was substantially responsible for FERC's ultimate conclusion in its August 6, 1979 report that the 1260 psig proposed by Alaska Northwest Natural Gas should be approved.

Jacob P. Billig

JACOB P. BILLIG

17/ Decision, pp. 193-194.

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THE STATE OF ALASKA ROYALTY OIL AUCTION: COMMENTS AND RECOMMENDATIONS

Tanzer Economic Associates, Inc.
Second Draft
November 19, 1980

The State of Alaska Royalty Oil Auction: Comments and Recommendations

This report lays out some suggestions on the possibility of auctioning off a portion of the state's royalty oil rather than taking payment from the Prudhoe Bay oil producers for the value of the oil. We believe that the state could do well in such an auction, and certainly better than it would by continuing to take this oil in value. Furthermore, we believe that the state should move forward as quickly as possible to hold such an auction.

The report is divided into two parts. The first part discusses the advantages of auctioning the oil over taking the oil in value. The second part examines the state's proposed "Invitation to Bid on State of Alaska Royalty Oil."

Part I Advantages to the State of a Royalty Oil Auction

The State of Alaska is entitled to 12.5% of all the oil removed or sold from all state oil leases in the Prudhoe Bay field as a royalty. At present this amounts to 187,500 barrels per day. The state is planning to auction off 45% of this royalty oil or 84,375 barrels per day.

It seems to us that there are two main goals in holding such an auction. First, to get more revenue for the state than it gets under the present system. At present the state receives from the Prudhoe Bay producers for its royalty oil "in value" money payments based essentially on the average per barrel price of Prudhoe Bay oil reported by the producers. Second, to use as some yardstick to try to determine whether in fact the prices reported by the companies for the "value" of Alaskan crude oil are true market prices, or are artificially depressed.

With regard to the increased revenue goal, there are three major factors which lead us to believe the state could obtain a higher price from a crude oil auction than it could get from taking its royalty in money. These are:

1) The "underreporting" effect -- based on the fact that the companies have a very strong incentive to report to the state artifically low prices for crude oil which are below true market prices.

2) The "security of supply" effect -- based on the fact that assured supplies of crude oil have a value to refiners greater than even "true" market prices.

3) A possible "location" effect -- based on the fact that the companies report to the state an (adjusted) average price based on the prices paid by refiners near and far from Alaska, while in theory the state auction would be most attractive to refiners near to Alaska who could normally pay higher prices.

The rest of Part I discusses the possible impact of these factors.

Underreporting of Market Prices
by Prudhoe Bay Producers

The first reason the state might reasonably expect from an auction a higher price than the in value payments is that all of the bidding companies know that the Prudhoe Bay producing companies have a strong incentive to report to the state "market prices" for Alaskan crude oil which are lower than real market prices. Historically, this has been because the combined state royalty and severance tax rate of **almost** 25% has made it profitable for the companies to shift their Alaskan profits from the crude oil production sector to their refining, transport and marketing divisions out of the state.

For example, one mechanism for the companies to shift their profitability would be to report fictitiously high tanker rates, thereby depressing the wellhead value. Another way would be to report fictitiously low crude oil sales prices, either by reporting sales within a company at arbitrary prices, or by working out deals with other companies for selling them Alaskan crude oil at below market rates in exchange for "swaps" in other places at below market rates. While this incentive has presumably operated in the past, the incentive to shift profitability away from the crude oil sector has been enormously increased by the federal windfall profit tax on oil, which came into effect in March of this year.

Basically, the "Crude Oil Windfall Profit Tax Act of 1980" provides that 70% of any company profits on crude oil production, above a relatively low base price level, must be paid to the federal government as a windfall profits tax. Of the remaining 30%, presumably with a normal 46% corporate income tax rate, the company is left with only 16% of the incremental profitability on Alaskan crude oil sales. A recent Business Week story on Tosco Corp. describes the implications as follows:

> "U.S. tax policy seems likely to bring on a dramatic shift in the pricing policies of the integrated oil companies, from which independent Tosco buys much of its crude. Under the new windfall profits tax, wellhead oil revenues are taxed up to 85%, while refining profits carry only the standard corporate tax rate. Big oil producers will thus be encouraged to sell their crude at artifically low prices in the U.S. while beefing up their refinery margins. This trend is already beginning to show up, Winston (Tosco President) believes."[1]

Note also that because of Alaska's combined royalty, severance and income tax rate, the incremental tax rate on crude oil profits is even greater. Assuming roughly an effective 31% combined Alaskan royalty and tax rate, from $1 of gross crude oil profits this would leave \$.69 profits, and after deduction of the windfall profits tax plus the federal income tax, this would leave \$.08, or implying for Alaskan oil a 92% combined state/federal tax rate on incremental crude oil profits; this would compare with possibly a tax rate below 50% for refining operations in states which have little or no corporate income tax rate (or where the operations may have piled up a loss for one reason or another, e.g. from earlier times when products were sold if necessary at losses in order to capture crude oil profits).

The key point about these very powerful incentives for the Alaskan producing companies to report fictitiously low or artifically low wellhead prices is that all of the refiners who would potentially bid at the state auction know that this is going on (because they are all active in the oil market trying to buy oil and can compare what the companies report to the state with their own experience). Thus, these companies know that the average reported price by the producing companies will be below the true market price, and this alone allows them to bid above the reported "in value" price without taking any risk at all.

Security of Supply

The second major reason the state might expect bids higher than the "in value" price is the security of supply factor. There is ample evidence that in today's world assured crude oil supplies have a greater value to refiners than their market price. One piece of evidence is the very high bid made by refiners like Amerada Hess to the state for the right to explore for crude oil in the recent Beaufort Sea Lease Sale. Even more dramatic evidence is provided from China, where major oil companies from all over the world, including some Alaskan producing companies, have undertaken seismic work at their own cost (which must be provided to the Chinese government) solely for the right to be considered to be allowed to bid for exploration drilling rights; moreover, if a company does win the right to drill for exploration, it will put up all the capital and technology and take all the risks and in return it will get if successful only the right to buy part of the oil produced at world market prices!

The value of Prudhoe Bay crude as a secure source of supply has been aptly pointed out by the Oil and Gas Journal:

> "The question then arises: Will (Prudhoe Bay) crude be as salable when fully decontrolled as it is today?
>
> The answer, by virtually all sellers and buyers, is yes.
>
> The reason lies in market demand for an assured supply of oil, competitively priced.
>
> Prudhoe Bay represents this assured supply for many years to come-in contrast to

uncertain deliveries from overseas, where political conditions can bring a sudden shutdown.

Also, West Coast refiners have learned, during 33 months of experimenting, to use crude of Prudhoe Bay characteristics far more than they anticipated when the field begin production in July 1977."[2]

The basic reason that assured crude oil supplies have a normal "value" greater than market price is that without those crude oil supplies, refiners and marketers in times of shortages face the real danger of either having to pay enormous premiums in the "spot" market (premiums over longer run contractual prices), or else go without crude oil, which means sharp reductions in the profitability (or even losses) of their refining and marketing operations. Particularly in refining, where there are enormous investments profitability is highly sensitive to the level of capacity operated at, and an inability to get crude oil can easily turn large profits into large losses.

By way of example and illustration, assuming refinery investments on the order of $5,000 per daily barrel of capacity, if refineries are to cover even a marginal pre-tax profit rate of 20% on investment plus 5% depreciation, they must generate $1,250 in cash flow per year for each barrel of daily capacity. Thus, the cash flow necessary to cover these capital charges amounts to about $3.50 per barrel. This is one measure of the premium that a refiner under these assumptions would be willing to pay rather than to be shut out of crude oil, and not be able to operate the refinery.

Location Effect

The third reason that the state might expect to receive a higher price from an auction is the average price the companies report to the state for crude oil purchases represents an average based roughly on two barrels of oil going to the West Coast of the United and one barrel of oil going a much longer distance to the Gulf of Mexico.

In theory, a refiner who is on the West Coast of the United States would be willing to pay a higher wellhead value for Alaskan crude oil than a Gulf and East Coast refiner, because of the lower shipping cost from Alaska to California's West Coast. Hence a state auction for a relatively small amount of oil, e.g., 85,000 barrels per day, should attract great interest from West Coast refiners who would be willing to bid a higher price because the value of Alaskan oil to them is greater than to Gulf and East Coast refiners.

By way of analogy, presumably the average reported price by the companies to the state consists of the price of a bottle of milk which is two parts cream (West Coast sale) and one part skim milk (Eastern Coast sale). By way of an auction the state can get bids solely on the cream rather than having to accept an average price for milk. By way of rough quantitative example, if there is an average transport differential between the West Coast and Eastern Coast of $3 per barrel,[3] everything else being equal, West Coast refiners would be willing to pay $3 per barrel more than Eastern refiners. With two-thirds of the crude oil going to the West Coast and one-third to the East, this would mean that the companies average reported price for Alaskan oil would be $2 greater than the Eastern prices. However, the West Coast refiners who would bid in the state auction would be willing to pay $3 more than the Eastern refiners, so that the state would thus be assured of getting $1 per barrel more than the average reported price.

However, due to the methodology that the state uses in calculating in-value prices for the purpose of royalty collection, the location effect has less than half of the impact indicated by our hypothetical example. This is because in-value prices are calculated in a way which reduces the influence of producers who report lower than average wellhead prices (see table 1). Specifically, each producers own weighted average price is calculated. Then, for each producer, the weighted price of all other producers is calculated. Finally, the highest of these two prices is taken as the applicable price for the calculation of royalties from each producer, and these applicable prices are themselves averaged, based on quantities produced by each produer. In our example, the locational effect works out to about 44¢ per barrel. Finally, the preceding analysis of the location effect is based on the simplifying assumption that the price of Alaskan oil in different locations differs only by its relative transport costs from Alaska. This obviously ignores the many supply/demand factors which affect oil prices in different regions, and as such it oversimplifies the problem. Nevertheless, this type of analysis is useful for indicating the possible order of magnitude of any tendency such as a location effect.

Combined Effect of the Three Factors

To illustrate quantitatively the possible cummulative impact that the three different effects discussed earlier might have on what the state could realize from a crude oil auction, versus what it would get from taking royalty oil in money, we use the following hypothetical values. Assume that the average wellhead value reported to the

TABLE 1[4]

The "Location" Effect on the Average Reported Price of Prudhoe Bay Oil

Producer	Delivery Point	Quantity Produced and Delivered	Wellhead Price	Weighted Average Price of All Other Producers	Applicable Price
A	West Coast	24 barrels	$24		
	Gulf and East Coasts	0	0		
producers weighted average price, producer A			$24	$22.69	$24
B	West Coast	26 barrels	$24		
	Gulf and East Coasts	26	$21		
producers weighted average price, producer B			$22.50	$23.56	$23.56
C	West Coast	17	$24		
	Gulf and East Coasts	7	$21		
producers weighted average price, producer C			$23.12	$22.97	$23.12
actual weighted average price of all producers			$23		
adjusted weighted average price of all producers					$23.56

Note: Example based on 67 barrels going to West Coast, 33 to East Coast. Producer A has 24% of supply, B 52%, and C 24%. All crude going to West Coast has a wellhead price of $24 per barrel. To Gulf and East Coast $21 per barrel.

state (for decontrolled oil) is $25 per barrel. Assuming an "underreporting" effect of $1 per barrel, the state might then expect to get $26 per barrel.

Assuming a "security of supply" effect of another $1 per barrel, the state might expect to get $27 per barrel. Finally, assuming a location effect of $.50, the state might expect to get $27.50 per barrel. In sum, the state might ultimately expect to receive 10% more than the $25 per barrel it would get based on the average price reported by the companies to the state. If the state auctions 85,000 barrels per day for 1 year, this amounts to 31 million barrels of crude oil, and the additional income would be almost $80 million. (Moreover, it would raise strong doubts about the realism or usefulness of "market prices" reported by the companies to the state.)

In conclusion, we believe that within a very broad range of possible supply/demand situations in world crude oil markets the combined impact of the underreporting, security of supply and locational factors will insure that the state will gain at least some additional revenues from an oil auction. It is worth noting the results of some recent U.S.

Government auctions of Western crude oil, as a possible guide to the gains from auctions in both boom and slack periods.

In California, the U.S. Government annually auctions off crude oil from the Naval Reserve at Elk Hills. In December, 1979, Phillips Petroleum bid $11.12 per barrel above the posted price, for a one year contract of 10,000 b/d of oil. In general, bids at that auction were $3 to $5 above posted prices (see table 2). This sale occurred during a time of strong demand for oil. In the previous 1978 auction, which came at a time of slack demand, winning bids averaged less than $1 per barrel above posted prices.[5] Similarly, a U.S. Government auction held in January 1980 for crude oil from the Teapot Dome field in Wyoming brought bids of up to $7.50 per barrel over posted prices; the Teapot Dome auction in 1978 drew bids averaging about 65¢ above posted prices.[6]

TABLE 2

High Bids in Elk Hills Sale* (December, 1979)

Company	Bonus above posting ($/bbl)	Volume (b/d)
Phillips	11.12	10,000
Fletcher	7.34	2,000
ARCO	5.32	15,000
Oasis Petro Energy	5.23	21,000
Mohawk	5.03	11,095
Pacific Refining	5.02	20,000
C. Itoh	4.82	10,793
Howell	4.47	3,200
Southwest Petrochem	4.26	4,000
Marathon	4.05	2,000
South Hampton	4.03	2,500
Beacon	3.95	3,020
Powerine	3.76	10,000
Mobile Bay	3.67	3,900
Union	3.65	4,300
Langham	3.52	250
Newhall	3.50	2,200
Sabre	2.84	1,000
USA Petrochem	2.68	1,120

*Preliminary results, subject to correction.

Source: Oil and Gas Journal, December 31, 1979, p. 54.

Part II Comments on the State's Proposed Document, "Invitation to Bid on State of Alaska Royalty Oil"

The comments here on the state's proposed "Invitation to Bid" focus on key procedures for which we suggest changes. Each subheading in this report refers to the paragraph and subject heading from the state document.

(1) Date of the Auction

The state has proposed that bids be received no later than December 18, 1980. We recommend that the date be set somewhat later, due to the fact that the OPEC oil minister's meeting will officially be held on December 15-16 and may extend several days beyond that.

As a result of the OPEC meeting there may be changes in the world's perception of the crude oil situation as well as the price of oil. Since such changes would affect buyers' bid at an auction, it would seem best to allow prospective bidders some time to digest the implications of the OPEC meeting. This could help reduce the general level of buyers' uncertainty about the future. Reducing the level of uncertainty for bidders should have a positive effect on bids, and state revenues, basically because uncertainty tends to lead to cautious and conservative assumptions about the future. (We have discussed this phenomenon as it relates to an analogous situation, cash bonus bidding for exploration leases, in our earlier report on "The Beaufort Sea Oil Lease Sale".[7]) Additionally, it would seem more equitable to the bidders to allow them to make their decisions on the basis of as much information as possible.

(2) Paragraph 2: Lots

The state's current proposal calls for the oil offered to be divided into 17 lots each consisting of roughly 2.6% of Prudhoe Bay royalty oil or 4,960 barrels per day (b/d) of oil (assuming total production from Prudhoe Bay of 1,500,000 b/d).

In theory, the state's total available amount of royalty oil could be auctioned off in many different ways. These could range from a "winner take all" system under which one company (or group of companies) would get all the oil, to a system under which the total oil would be divided into smaller lots, e.g., 1,000 b/d, and as many as 85 companies could be winning bidders.

Our belief is that the state's revenues might best be maximized by a different type plan, which would allow each company to bid for exactly the amount of crude oil it desires. The total quantity available would then be awarded to bidders on the basis of the highest bidder first getting its desired amount of oil, the second highest bidder getting its desired amount, etc. until all the oil was gone. (To accommodate bidders who were not interested in small quantities of oil, a bidder could be allowed to set a minimum quantity that it desired at its bid price.)

We see two basic advantages to this approach. First, it would give companies a chance to fill their exact crude needs, without requiring them either to bid for less oil than they want, or to form groups to bid for the round lots offered or to resell the undesired quantities of oil -- all of which steps involve undesirable costs and risks that will tend to reduce the bid prices companies would be willing to pay. For example, if the lots are divided into units of roughly 5,000 b/d, and a company wants 7,000 b/d, it faces the choice of bidding for only 5,000 b/d, or finding a partner which wants 3,000 b/d enabling it to bid for 10,000 b/d, or bidding for 10,000 b/d and gambling on its ability to resell 3,000 b/d in the future. Presumably all of these choices are less than optimum for the company, and this should tend to make the company unwilling to pay as high a price for either 5,000 b/d or 10,000 b/d as it would pay for 7,000 b/d.

The second reason for allowing "specific bidding" is that it could attract bids from smaller independent refiners, who have little or no crude oil of their own, and who thus have even greater needs for security of supply than bigger refiners. Therefore, presumably these smaller refiners would be willing to pay a higher price than larger companies for the state's oil. (This tendency might be reinforced by the fact that the smaller refiners do not have national or international networks of crude oil contractual arrangements which might be jeopardized by "bidding too high".)

Evidence of the important role that bids for relatively small quantities can play in maximizing auction sale revenues can be seen from results of the December 1979, Federal Elk Hills Auction (See Table 2). Of the 19 winning bids, 12 were for less than 5,000 b/d (including one for only 250 b/d), and these 12 combined accounted for almost one-fourth of the total volume auctioned.[8]

We would also argue that insisting on lots of the magnitude of nearly 5,000 b/d would discourage the bidding of small processors within the state who may need a smaller supply in order to undertake a new project. It has the effect of discriminating against small business. Eliminating these potential smaller bidders could discourage small scale economic development which would benefit the people and the state of Alaska.

(3) Paragraph 3: Term

The state's proposal for the oil to be sold for a term of one year is a good one. This longer period of time is preferable to the 6-month period proposed earlier for at least two reasons.

First, a sale covering a longer period is more likely to increase the number of bidders for Alaskan oil. This is because for a refinery that has not previously been using Alaskan crude oil, there are costs it must incur in order to adjust its equipment to handle such crude oil. Therefore, it would normally be more attractive to such refiner to undertake those investments if its Alaskan crude oil supply was assured for a longer period. Moreover, industry sources we have talked to indicate that an assured supply for one year would normally be sufficient to make a refiner willing to make the adjustment.

Second, a longer term contract would also be more attractive to companies since a large part of their interest in Alaskan crude would be as protection against a serious shortage of crude oil. While at present there is no such shortage, the possibilities of such a shortage are expected to increase as time passes. Hence, the longer the time period covered by the auction sale, presumably the greater the premium oil refiners would be willing to pay for protection against possible future shortages.

We disagree with the provision allowing buyers to terminate their contracts.

First of all, upon termination of a contract the state's income from royalty oil would be reduced. If the oil were to revert back to the producing companies the state would get only the in value price and no premium. If the oil were to be resold by the state to another buyer, the price would likely be lower than the bid in the original auction. This is because the time period of the contract would be reduced, and the competitive conditions, given the termination, would almost certainly be worse.

Secondly, a termination clause is not necessary in terms of equity for the bidders. The bidders would be protected against extreme deviations between the future market price and the price they ultimately pay by the provisions tieing the auction price to the in value price reported at the time of delivery (see discussion on paragraphs 6 and 7). Thus, if market conditions changed sharply in the future, the in value price would change in the same direction.

Finally, a certain amount of risk would have to be expected in any kind of crude oil sale. To eliminate that risk might encourage irresponsible bidding which ultimately could hurt the state.

The Federal government had a similar clause in its regulations for the Elk Hills Naval Petroleum Reserve auction in December 1979. The highest bidder, Phillips Petroleum, the fourth highest, Oasis Petro Energy and the sixth highest, Pacific Refining, all cancelled when it appeared that their bids priced the oil above alternative supplies.[9] The rules govering the next Federal government sale (December 1980, Kern County, California) contain no provisions for cancellation.[10]

(4) Paragraph 6: Price

The state's current proposal establishes the base price to which the premium bid will be added as the reported in value price of Prudhoe Bay oil as computed under the Exhibit B formula the state uses to calculate in value royalties at the time the oil is delivered to the bidder (hereafter referred to as the base price).

This is far superior to using a fixed price as a base and possibly exposing the state to loss of revenue from jumps in oil prices.

The state may wish to consider establishing the base price, to which the bid premium will be added, as equal to the exhibit B reported in value price at time of delivery plus a certain dollar amount which would account for possible additional costs to the state of an auction. This precaution could protect the state against the possibility of receiving less in total for its oil than if it had not auctioned it. For example, Standard Oil of Ohio pointed out in its comments on the auction regulations that if the auctioned oil goes to the West Coast and displaces a Prudhoe Bay producer's oil from the West Coast to the Gulf Coast this could lower the wellhead price for all Prudhoe crude, thus lowering the state's royalties, severance and income tax. If the premium received at the auction is insignificant the state's gain from the auction could be less than its loss of income from the lower wellhead value.

Our preliminary examination of SOHIO's point indicates that theoretically, under certain extreme assumptions, the effect could be significant. Given this possibility the state should be prepared to protect itself against a possible reduction of revenues. As a first step we recommend that the state government, which has all of the detailed data on previous sales, carefully analyze this effect and estimate what the dollar magnitude might be. Secondly, the state could then use this estimate of the dollar amount to protect itself against any such future loss, by adding it to the base price (i.e., adding it to the future in value price). In effect, then, the state would establish a minimum premium bid.

(5) Paragraph 7: Premium

An alternative to the state's proposed premium expressed as a flat dollar amount in dollars and cents is one based on a percentage of the price defined in paragraph 6. Instead of bidding $5 over a projected hypothetical base price of $25, a buyer would bid a premium of 20%. A percentage may more accurately reflect changes in market conditions. The greater the rise in prices the greater the premium received by the state. In terms of equity to the bidder, if future prices were to rise sharply, this would indicate an unexpected scarcity of oil, and bidders would be quite happy just to have access to the crude oil. If prices failed to rise to the levels expected by the bidders, a percentage bid would result in their having to pay a lower premium reflecting the lesser value of the oil to them. In our opinion, there is a greater likelihood that any unforeseen change in future prices will be in an upward rather than a downward direction, and a percentage premium would thus be advantageous to the state.

(6) Paragraph 9: Security

This provision, which establishes a fixed security bond per lot, would, as paragraph 2 does, act to discriminate against possible small bidders. Although foregoing a large security may increase somewhat the risks to the state, it would have the effect of serving other goals of the state, such as encouraging small business. The ability of a small buyer to fulfill its obligations of the contract could better be judged under the detailed specific provisions of paragraph 11, "Qualifications of Bidders".

A more equitable arrangement would be to tie the amount of bond to the quantity of oil bid on. A small buyer, bidding on several hundred barrels would pay a much smaller bond than a buyer bidding for 10,000 or 20,000 barrels.

7. Conclusions

In conclusion, we would recommend the following changes in the invitation to bid:

Paragraph 2, Lots: Allowing buyers to bid on exactly the amount of crude they need rather than on the proposed 17 lots of about 5,000 b/d each.

Paragraph 3, Term: Keeping the term of the auction contract for one year, but eliminating the provision allowing bidders to cancel their contract.

Paragraph 6, Price: The state should closely examine the possibility of the auction displacing North Slope producers' oil from the West to Gulf Coast and lowering the average wellhead price. It should consider establishing the minimum bid price as the in value reported price of the oil at the time of delivery plus a dollar amount which would offset any estimated possible state loss from a lowered wellhead value.

Paragraph 7, Premium: A percentage premium, equal to a percentage of the in value price at the time of delivery, should be used, rather than a flat dollar and cents premium.

Paragraph 9, Security: The amount of security should not be a flat amount, but should be tied to the quantity of oil for which a bid is made.

FOOTNOTES

1. Business Week, October 6, 1980, p. 36.

2. Oil and Gas Journal, April 21, 1980, p. 28.

3. Transport cost differential between the West and Eastern Coasts from, Department of Energy, Economic Regulatory Administration, "Alaska North Slope Entitlements Adjustment" (Washington, D.C., U.S. Department of Energy, September 12, 1980) p. 8.

4. Calculation of transport differential's effect on average weighted price of oil is based on formula in "Exhibit B, Alaska Petrochemical Company: Alaska Royalty Crude Oil Contract" February 22, 1978, pps. B-1, B-2.

5. Bids for Elk Hills from Oil and Gas Journal December 31, 1979, p. 54.

6. Teapot Dome data from Oil and Gas Journal January 21, 1980, p. 53.

7. Tanzer Economic Associates, Inc., "The Beaufort Sea Oil Lease Sale: A Comparative Analysis of Different Bidding Systems." (A Report to the Alaska State Legislature) January 4, 1980, pps. 12-13.

Footnotes, continued

8. Oil and Gas Journal, December 31, 1979, p. 54.

9. Platt's Oilgram News, March 28, 1980, p. 2.

10. U.S. Department of Energy, Naval Petroleum Reserves in California, "Invitation for Bids for the Competitive Sale of Crude Oil from Naval Petroleum Reserves No. 1 and 2. Kern County, California" (IFB No. DE - FB01 - 80RA 32119) (Washington, D.C., U.S. D.O.E., October 21, 1980) p. 34.

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Witlow

A CURRENT PERSPECTIVE ON USE OF NATURAL GAS LIQUIDS FOR PETROCHEMICAL PRODUCTION IN ALASKA

10 January 1979

Prepared for

Royalty Oil and Gas Development Advisory Board
State of Alaska

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SUMMARY

Bonner & Moore has prepared an overview of the current situation as regards the prospective development of a petrochemical industry in Alaska based on the use of natural gas liquids produced at Prudhoe Bay.

At the present time, the prospects of selling Prudhoe Bay gas at regulated ceiling prices appear to be dimming. While this is an unwelcome development for Alaska, in that it reduces the royalty value of North Slope gas production, it enhances the prospect that the alternate value of these materials as petrochemical feedstocks will become their most economic disposition and therefore provide the greatest benefit to the state.

Regulatory delays, high transportation costs, and a generally negative perception of the business climate in Alaska have resulted in an impasse over the matter of gas production and sale. The prospects of catalyzing industrial leadership in the use of gas liquids in-state are poor for these reasons. A thoughtful consideration of alternatives has led Bonner & Moore to a reluctant but firm conclusion that only a commitment by the state to lead these activities can significantly enhance the prospects of in-state petrochemical development.

We recommend that a legislative proposal be prepared to authorize the following activities:

1) The design and firm cost estimation of a gas liquids line from Prudhoe Bay through Fairbanks to Kenai.

2) The development of plans for state financing.

3) Preparation of a recommendation for state or private financing.

4) Development of plans for state financial participation in an operating company (should that option be recommended) and solicitation of business from producers and prospective purchasers of gas liquids.

Evaluating the use of gas liquids for in-state petrochemical manufacture requires that realistic alternate values of gas liquids be clearly understood so that their net value to the state can be maximized. The value of gas liquids for petrochemical feedstocks is at least 30 percent lower at a tidewater Alaskan plant site than if the same material were available to a comparable plant on the U.S. Gulf Coast. The wellhead value is further reduced in Alaska by the high cost of transportation.

If Prudhoe Bay gas can realize the regulated gas ceiling price (currently $1.63/MMBTU) at the wellhead, its greatest direct revenue benefit to the state will be for interstate pipeline sales. If the wellhead value is reduced from the ceiling price by deduction of conditioning and compression costs the greatest net benefit to the state from the gas liquids may well be as petrochemical feed and LPG sales although the precision of current data are not adequate to make this distinction. If the wellhead value is determined by free market forces in the lower 48 states, the greatest net benefit derivable from the gas liquids will be from in-state recovery and use.

It is Bonner & Moore's opinion that the various uncertainties surrounding the Alaska gas pipeline will be resolved unfavorably and that in-state use of gas liquids will provide the greatest net benefit to the state.

This opinion plus the anticipated prolongation of regulatory proceedings relative to the whole matter of the gas pipeline leads us to the recommended course of action. This is the only approach we can see that will enable the state to influence events favorably toward petrochemical industry development.

Furthermore, recent OPEC increases in crude oil prices, coupled with continuing control of U.S. gas prices is a favorable development with regard to making in-state petrochemical use of gas liquids more economically attractive relative to their pipeline sale or use as fuel at Prudhoe Bay.

FURTHER DISCUSSION OF BONNER & MOORE'S PRIOR ROYALTY GAS STUDY

The earlier Bonner & Moore study of royalty gas utilization developed some values of ethane for petrochemical use. The values were a function of presumed petrochemical product prices, the costs of manufacture, and the cost of transportation. That study considered many options of geography and quantities of recovered ethane plus associated gas liquids.

The most favorable case examined, namely the case that produced the highest ethane value, determined a value of $1.24/million BTUs at Prudhoe Bay. Since completion of that study other considerations have directed interest primarily toward the case where gas liquids are recovered at Prudhoe Bay and pipelined to a tidewater location.

Using data from the earlier report, gas liquids recovered and used as petrochemical feedstocks would incur the following costs:

Recovery of C_2 + liquids at Prudhoe Bay	$1.08/Bbl
Pipeline Transportations to Kenai area	$2.23/Bbl
Total Recovery and Transportation Cost	$3.31/Bbl
or @ 3.053 MMBTU/Bbl	$1.08/MMBTU

The feedstock value calculated from petrochemical prices and manufacturing costs is $2.10/MMBTU. Subtracting the costs of $1.08/MMBTU from this value yields a value at Prudhoe Bay of $1.02/MMBTU. This petrochemical value must be compared to the fuel value to determine which use value is the higher. If the gas liquids are to be used for petrochemical feedstock, then they must command the higher value in that use.

This petrochemical value of roughly \$1/MMBTU at Prudhoe Bay must be compared to the BTU value of hydrocarbons transported to the lower 48 states through the proposed Alaska Gas Pipeline.

Under provisions of the Natural Gas Policy Act of 1978, Prudhoe Bay gas would have a current regulated ceiling price of \$1.63/MMBTU. It is unknown, at present, whether this price will be allowed for any gas at the wellhead or only for gas meeting the following standards:

Total Sulfur (gr./100 cf.)	20 maximum
Hydrogen Sulfide (gr./100 cf.)	1 maximum
Water (lb/MMCF)	7 maximum
Carbon Dioxide (volume percent)	3 maximum

Other impurities requiring the buyer to incur costs to meet pipeline requirements

It would appear that proposed regulations for gas pricing, as they might affect Prudhoe Bay production, will be determined by special review of FERC (Federal Energy Regulatory Commission). The specific issue is whether the ceiling gas price would be *increased* by the cost of "gas conditioning" at Prudhoe Bay or whether those costs would be *included* in the ceiling gas price.

To illustrate how this determination could affect the alternate fuel value of Alaskan gas liquids, consider the following scenarios.

Scenario 1

Prudhoe Bay gas is allowed a regulated price of $1.63/MMBTU plus the cost of gas conditioning and the gas is successfully sold at this price.

Scenario 2

Prudhoe Bay gas is allowed a regulated price of $1.63/MMBTU but no added allowance is made for gas conditioning cost.

Scenario 3

Prudhoe Bay gas can be sold only at a market clearing price in competition with other gas supplies available to purchasers in the lower 48 states.

The cost of gas conditioning has not been developed to the same degree as the costs associated with pipeline operation. However, based on a preliminary study of gas conditioning made by Ralph M. Parsons Inc., it could be expected that conditioning costs in the range of $0.50 to $1.00 per MMBTU would be incurred. For subsequent use in our analysis a figure of $0.75/MMBTU will be used for the cost of gas conditioning including compression to pipeline pressure. With such a figure, the three scenarios can be examined to see what circumstances will lead to the use of gas liquids for in-state petrochemical development.

Scenario	Pipeline Value of Gas Liquids at Current Price Levels ($/MMBTU)	Prospects for In-State Petrochemical Use of Gas Liquids
1	1.63	None
2	0.88 (est.)	Feasible
3	Nominal	Good
Petrochemical Value	1.00 (est.)	

In scenario 3 it is unlikely that the Alaska gas line would be built, at least in the foreseeable future. In such a case, the producers could well make a concerted effort to recover and sell gas liquids from Prudhoe Bay, reinjecting only a lean gas stream back into the reservoirs.

In scenario 2 the alternative of selling gas liquids would probably be given serious consideration and improved cost estimates prepared. State assistance could make an important difference, in this case, as to whether or not in-state use or sale would be pursued by the producers.

The determination of which scenario will prevail must first await the final regulations on gas pricing to be adopted by FERC. Even these regulations will not completely define the gas pipeline's future because the entire gas project has not met the test of market acceptance. In the view of Bonner & Moore, the gas pipeline project, or at least the Alaskan portion, is not economically sound. Only substantial government subsidization or favorable regulatory bias toward the project will enable its realization. Probably another 12 months will elapse before the alternate values of Prudhoe Bay gas can be forecast with accuracy.

STATE PARTICIPATION IN DEVELOPMENT OF GAS LIQUIDS BASED INDUSTRY

The three most important obstacles to positive action by private industry to develop an Alaska-based petrochemical industry are:

1) continuing uncertainty in Federal regulatory policies,

2) high cost of bringing feedstocks to the south coast of Alaska, and

3) a suspicion that Alaska will not provide a hospitable regulatory or economic climate for large industrial concerns.

The state can alleviate (although not eliminate) all these obstacles by a forthright recognition of the special problems facing Alaskan development and committing to a program that materially improves the economic climate.

In the specific case of gas liquids utilization, this probably means that the state should seriously evaluate the financing and encourage development of a pipeline system to bring gas liquids from Prudhoe Bay to tidewater. If such a project were developed and approved for implementation by the state, subject to appropriate utilization contracts, serious competition for the use of gas liquids should follow.

The state can offer two advantages in this role. One is positive leadership. The second is more favorable financing terms that could reduce the calculated transportation and processing cost of $1.10/MMBTU for gas liquids by, perhaps, 15-20 percent.

The state can take other steps that would be complimentary to a program for building the necessary pipeline system. These would include the development of streamlined permitting procedures and the compilation of data pertinent to the costs of operating a petrochemical enterprise in Alaska.

Bonner & Moore's recommendation is that the state immediately embark on a two-pronged program aimed at determining the feasibility of a state-financed pipeline project for transporting natural gas liquids from Prudhoe Bay through Fairbanks on to the Kenai Peninsula.

One activity would be the design and cost estimation for the line. The second activity would be to investigate financing alternatives and prepare cost projections for operation of the system.

This program might result in either a state-financed operating enterprise or in private interests becoming involved as the project grew more clearly defined.

The principal expense would be the design and cost estimate for the line. This would be a major item and would require a special appropriation. An estimate of this cost is being prepared and will be supplied within a few days.

The program for promoting petrochemical industry development that has been proposed by the Royalty Board seems completely appropriate to a situation where a course of action is to be influenced. At the present time, however, the state is confronted by inaction.

In our opinion the state faces two choices in pursuit of petrochemical industry development. It can lead or it can follow. This presumes that a third choice of opposition is null. Since there is clearly a leadership vacuum, and may well continue to be, the Royalty Board should prepare a legislative proposal for state leadership in building the key pipeline component of a system to use gas liquids in-state.

Such action goes beyond studies and positively furthers the prospect of actual development. The risk can be confined to the cost of engineering design and cost estimation plus perhaps 30 percent additional cost for ancillary activities.

More accurate investment figures and financing studies may disclose that the construction and operation of a gas liquids pipeline is a proper private investment. It may also show that transportation costs can be kept to adequately low levels only if the enterprise benefits from low cost financing and tax exemption through state participation.

The Royalty Board should sponsor development of these alternatives and recommend the form of enterprise to build and operate a pipeline. At that time offers for the use of the pipeline and for use of the states' Royalty Gas liquids (possibly augmented by BTU equivalent swaps of liquids for lean gas) can be solicited with good prospects for constructive responses.

BACKGROUND: Forecasts of Petrochemical Feedstock Values and Comparisons Between LPG, Naphtha, and Gas Oil for the Production of Ethylene

Ethylene is the world's major petrochemical product. Ethylene is used in the production of other materials and is purely an intermediate material. Plastics and anti-freeze are the two largest volume derivatives of ethylene.

Ethylene, and a similar material propylene, were first produced in large quantities from ethane and LPG (propane and butane). The historically low price of natural gas relative to crude oil and the simpler technology required to "crack" ethane and LPG to ethylene made these materials the preferred feedstocks for U.S. ethylene plants.

In Europe and Japan there has been no natural gas industry or gas liquids imports until recent years, and so ethane and LPG were not available as large volume feedstocks for ethylene manufacture. Consequently, technology was developed to produce ethylene and other olefins in those areas from hydrocarbons heavier than LPG, primarily naphtha.

Rising natural gas prices and prospective shortages of ethane have caused the construction of new ethylene producing capacity in the U.S. that utilizes naphtha and even heavier materials such as gas oil for feedstocks. Since technology exists to use these heavier feedstocks that derive from crude oil, their cost serves as a stable reference point against which other feedstocks can be compared.

If we examine the trends in prices for crude oil and natural gas, including the price-related ethane and LPG materials, we can see how the petrochemical value of natural gas liquids will compare with their price fuel or BTU value. In this analysis, the general case for the lower 48 states is considered. The special circumstances pertaining to Alaska can then be considered and some fairly specific conclusions drawn.

Crude Oil Pricing

Crude oil production for the U.S. should peak near 1990. The rise from today's production through that period will result from the inclusion of Alaskan crude oil and new offshore production which will offset the current and continuing decline of production in the contiguous 48 states.

Crude oil demand will continue to rise steadily through 1990 and then begin to slow its rate of ascent. Crude demand, however, will increase faster than production rate increases and the U.S. will be importing an ever-increasing percentage of its crude oil requirement.

Bonner & Moore's projection of domestic production, foreign imports and total demand for crude oil is illustrated in Figure 1.

We do not expect that crude oil price increases will be uniform or capable of being "programmed". Rather, they will most likely come as a result of supply and demand forces interacting with steep increases in years of strong economic recovery followed by declining real-dollar pricing for several years thereafter.

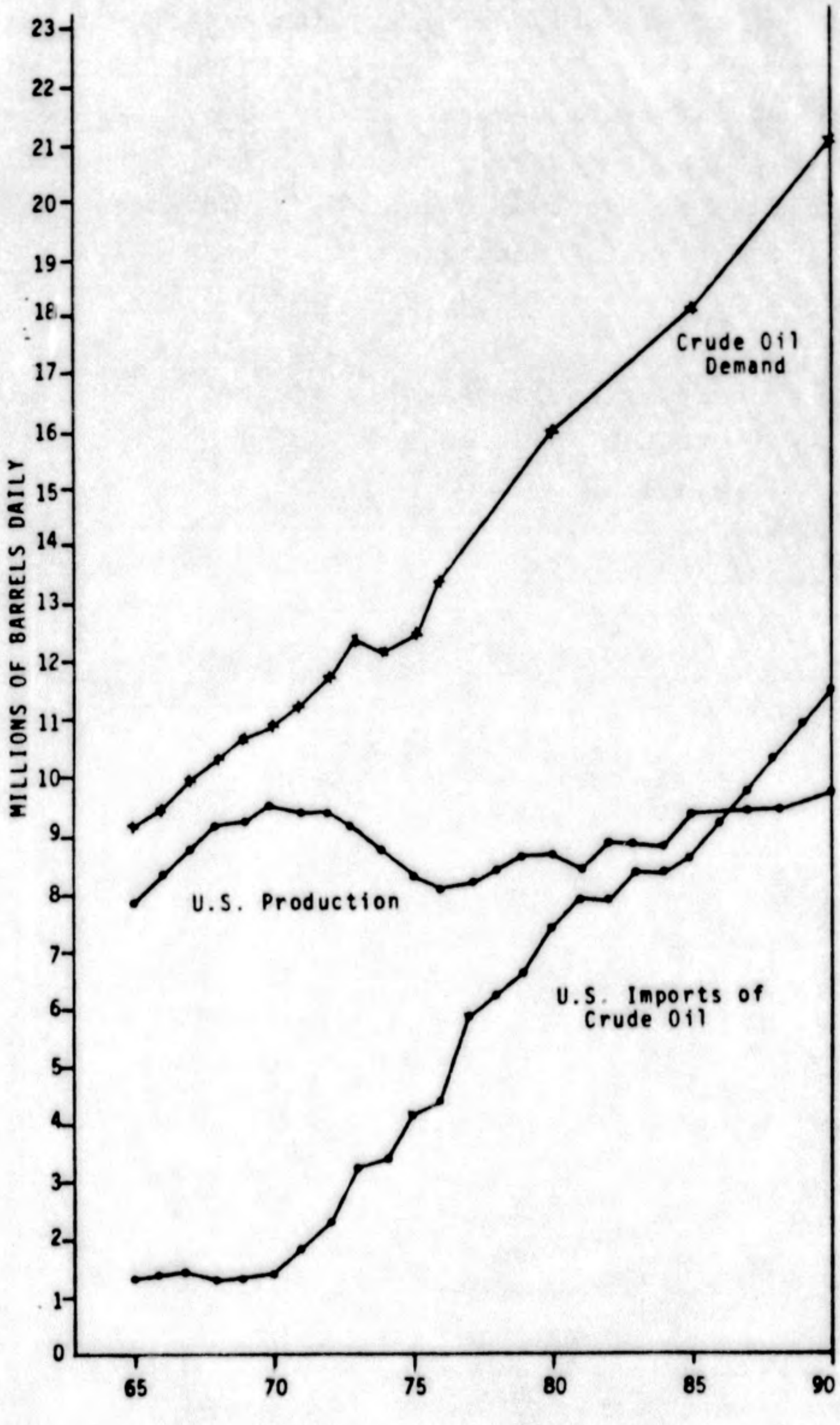

Figure 1. Crude Oil Supply & Demand
(MMB/D)

Major energy legislation which succeeds in the development of a rational energy pricing pattern is not likely to occur before 1980. Any plan so developed will follow the regulatory framework envisioned by the present energy legislation on natural gas with multi-tier pricing levels resulting in eventual decontrol. Such decontrol is expected to occur in the vicinity of 1990 rather than in the 1980 area.

The demand projection--plus identified pricing influences will result in average U.S. crude oil costs as reflected in Table 1.

TABLE 1

U.S. GULF COAST CRUDE OIL PRICE FORECAST

1970-1990

(Current Dollars)

YEARS	$/BARREL	$/MMBTU
1970	3.25	0.59
1975	10.28	1.85
1980	13.42	2.42
1985	20.50	3.65
1990	31.50	5.68

Light Gas Oil (No. 2 Fuel Oil)

The pricing of No. 2 fuel oil is primarily a function of crude oil acquisition costs. Although No. 2 fuel oil prices will vary as a function of capital costs, operating expenses and the condition of the fuels market, prices can be expected to vary between 11 and 14 percent above crude oil prices over the foreseeable future. Using factors developed in a 1975 Bonner & Moore study for the Department of Transportaiton, the price for No. 2 fuel oil (at the refinery gate) is projected as shown in Table 2.

TABLE 2

U.S. GULF COAST PRICE PROJECTION FOR NO. 2 FUEL OIL
(Current Dollars)

YEARS	$/BARREL	$/MMBTU
1970	4.27	0.73
1975	11.59	1.98
1980	15.37	2.63
1985	22.88	3.91
1990	35.60	6.08

Natural Gas Pricing

Natural gas pricing bears little resemblance to rational supply/demand relationships. The events of the past 18 months have shown natural gas pricing to be both volatile and politically sensitive. From past analyses, we could expect natural gas to maintain a 20 percent or higher price premium in an unregulated market due to its environmentally superior nature. However, many industrial markets will likely be closed to the use of natural gas by federal and state restrictions.

Further, the Natural Gas Act of 1978 appears to have set the pattern for gas pricing during the next 5 to 10 years. This pattern suggests that natural gas price at the wellhead will:

1) Continue to be controlled,

2) Have a maximum price equal to replacement cost with No. 2 fuel oil, and

3) Have a price based on "vintage" categories which will impact each region, company and consuming group differently.

To understand the magnitude of the price variations authorized by the Natural Gas Act of 1978, the wellhead ceiling prices for several categories of natural gas are presented in Figure 2. These prices are shown as they would be computed if gas deregulation does not occur and controls are extended to 1990. Additionally, our projection of No. 2 fuel oil price at the refinery gate (U.S. Gulf Coast) is shown for comparative purposes. It is seen that natural gas priced equivalent to No. 2 fuel oil would violate the ceiling price by 12 percent.

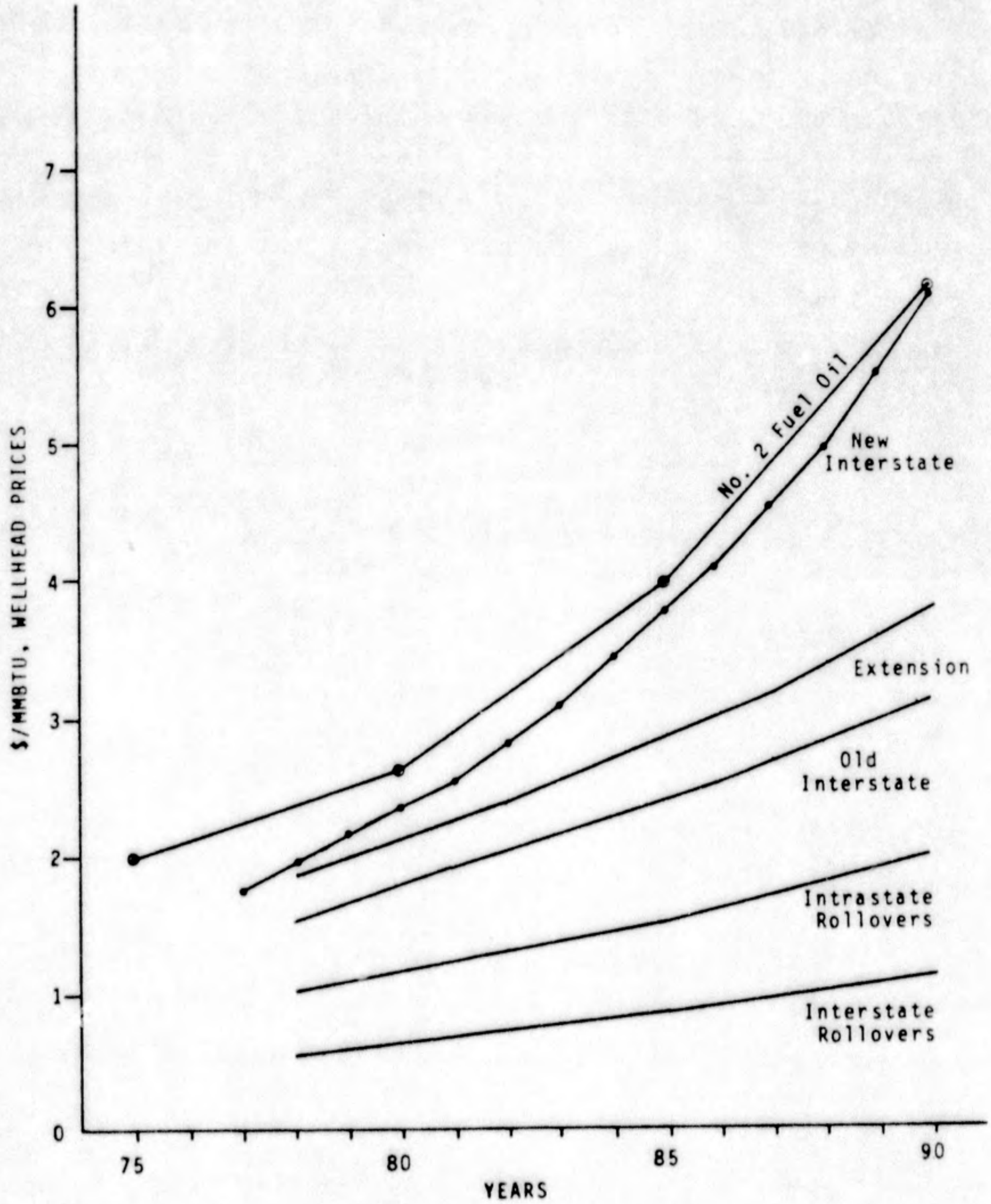

Figure 2. Possible Ceiling Prices For Natural Gas Under Senate-House Compromise Provisions (Excludes Severance Tax)

If natural gas were priced at 120 percent of the price for No. 2 fuel oil, the violation would be by 32 percent. We must, then, conclude that natural gas will be priced at or below No. 2 fuel oil for the years 1978 to 1990--even though many industrial consumers could afford to pay 20 percent or more above the price for No. 2 fuel oil for natural gas because of environmental, current logistical and structural considerations.

Pricing of Ethane and LPG

The forecasting of Ethane and LPG pricing requires a complex mechanism which includes the selection of the pricing basis by which the value of each component (ethane, propane, butane and C5-and-heavier) will be determined. It is expected that the pricing bases for some or all of these components will change over time.

For example, consider two situations under which pricing is computed.

First, assume that natural gas at the wellhead is priced so that, on balance, it is below the cost of No. 2 fuel oil when it reaches its ultimate consumer. This was the situation existing prior to the 1973 oil embargo. The extraction of LPGs from the gas stream, if the extracted products were valued at competitive fuel prices equivalent to No. 2 fuel oil, represents an upgrading of the value of the natural gas stream. In 1970, for instance, fuel oil sold for 73 cents/MMBTU, natural gas sold for 22 cents/MMBTU and propane sold for 69 cents/MMBTU. By extracting propane, the seller of natural gas could leverage his natural gas value by obtaining a product in a more easily transportable form which could bear a much higher final sales price. Further, propane was not regulated and the profit from its sale was not included in the rate base. The cost base at the extraction plant was its fuel value as natural gas--not its value in the regulated market place. The important point is this: *The liquids from a natural gas stream sold for a market value far in excess of the regulated natural gas price, and this "upgrading" process was profitable even considering the operating and capital costs connected with extraction of liquids from the natural gas stream.*

Now, as a second situation, assume that natural gas is priced as a "fuel" in its own right--having a value nearly equal or above that of a competing fuel, No. 2 fuel oil. At this juncture, what was "upgrading" in the first situation reverses to a "downgrading". *The extraction of liquids incurs costs which raises the cost base for the liquids while creating a product which sells for approximately the same price as the initial feed--natural gas.* In our analysis, the point at which the "upgrading" turns to "downgrading" is when natural gas reaches approximately 64 percent of the price for No.2 fuel oil.

Earlier it was stated that natural gas is fairly priced in the market place when natural gas at the wellhead in the present gas producing areas reaches 80 to 120 percent of the price for No. 2 fuel oil on the Texas Gulf Coast. In the foregoing paragraph, we stated that natural gas liquids extraction is attractive only when natural gas is priced at less than 64 percent of the price for No. 2 fuel oil and that extraction is affected negatively when the price for natural gas exceeds that level. Clearly, our projections imply that liquids extraction will be negatively affected and thus, that the price of some or all of the component LPGs will have to sell above their BTU value if new extraction plants are to earn a fair return on invested capital.

Extraction Costs

The cost of extracting LPGs is dependent on the cost of the feed to a natural gas extraction plant, the fixed expenses (manpower, maintenance, etc.), the variable expenses and the revenues to recoup the investment and provide a return on that investment. These components of extraction cost should be spread over the sum of products recovered and the total dollars of revenue received should equal or exceed the costs. The bases we used to allocate the total cost is the weight basis fraction which each component recovered has in the final product mix.

Figures 3 and 4 show the results of our calculation of costs, on a weight basis, for ethane and propane. Further, the value of each stream is shown at its heating value if ethane and propane sold at the then existing No. 2 fuel oil price on the Texas Gulf Coast. Note that costs are shown with and without capital recovery, demonstrating the range within which prices may fall, based on recovery of fixed plus variable charges (w/o CR) and with full recovery of profit plus depreciation (w/CR). The difference between the two represents the leeway which the extraction plant has to lower prices during periods of slack demand.

If we assume that the general market for propane is for heating and that no substantial price differential will exist for environmental reasons (which is consistent with the 80 percent value of natural gas relative to No. 2 fuel oil) then it is clear that the value of propane, over time, will be below the cost of its extraction. We can forecast this in light of our comments regarding the breakpoint of 64 percent for natural gas pricing relative to No. 2 fuel oil.

To clarify the likely price decisions which will be made, it is necessary to define the alternate values which exist--that is, values based on something other than fuel-based value or value based on extraction cost.

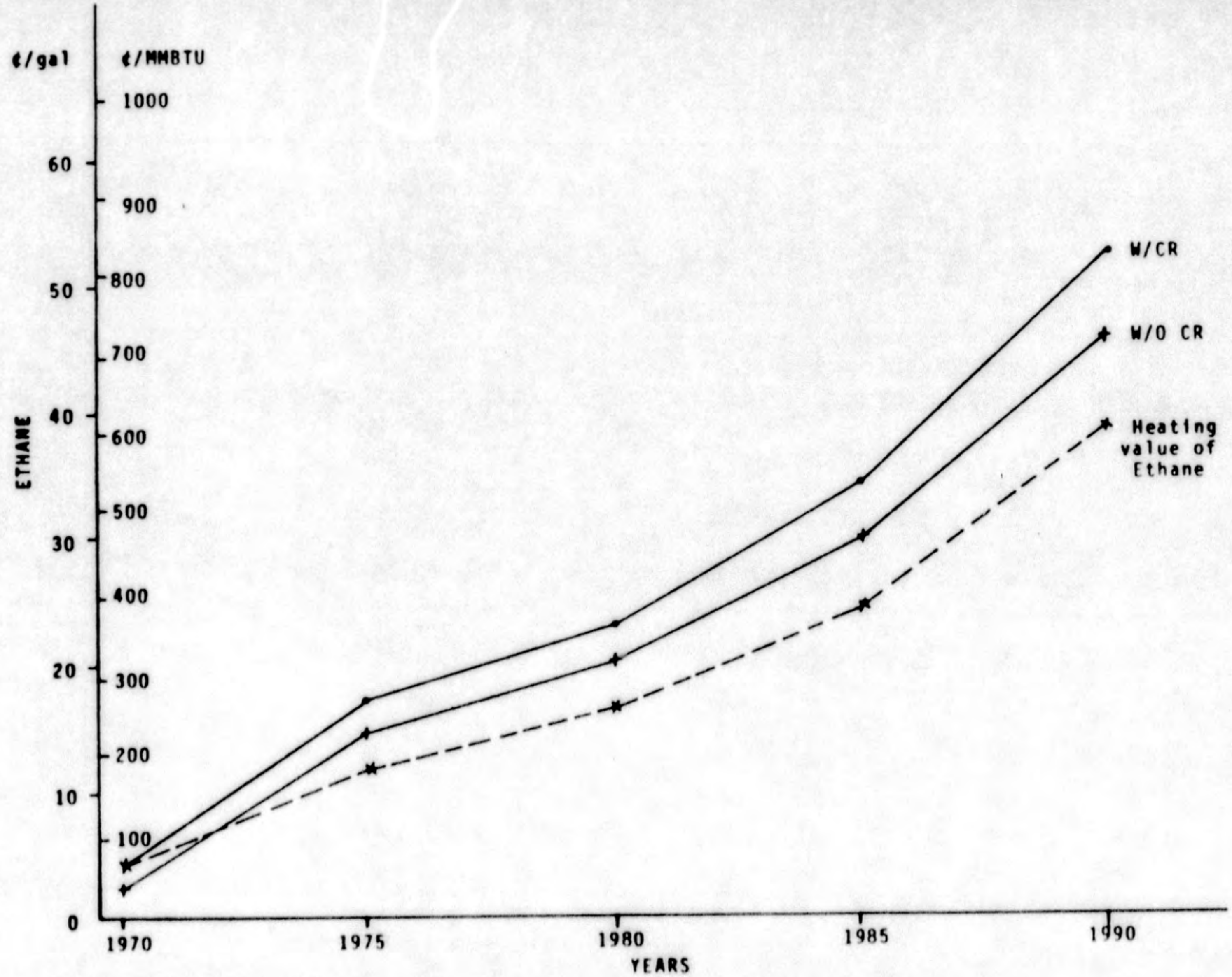

Figure 3. Cost of Extraction Basis--Ethane

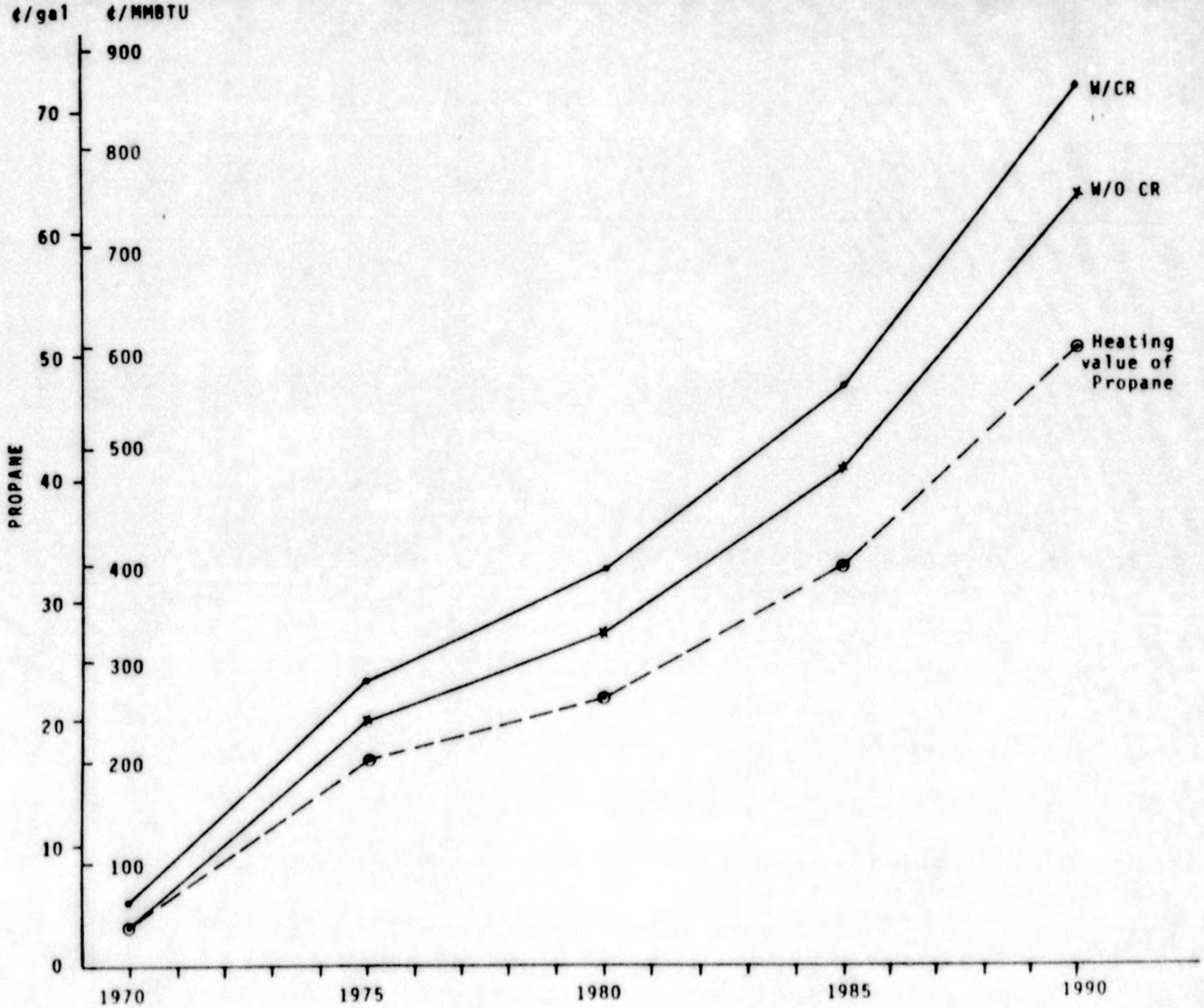

Figure 4. Cost of Extraction Basis--Propane

Alternate Values

The paragraphs in this subsection explore the alternate values for each component natural gas liquid.

Alternate Value for Butanes and C5 and Heavier

The highest alternate value for Butanes and C5 and heavier components are as refinery feedstocks. Based on a study performed for the Department of Transportation in 1975, we forecast the following values:

YEARS	ALTERNATE VALUES (Cents/Gallon)	
	Butanes	C5 and Heavier
1975	18.98	22.74
1980	26.17	29.93
1985	45.17	47.79
1990	61.60	71.31

Although the ratio of product price to crude oil price might vary under the specific assumptions used in this study, the 1975 study which we utilized is sufficient for these projections. The above prices are for the U.S. Gulf Coast.

Butanes and C5 and heavier components have limited use in petrochemicals. However, we expect during the time period under investigation, that the controlling alternate value will be as feedstocks in refineries.

Ethane and Propane Alternate Values

Propane's alternate value, other than as a fuel, will be determined by the price which the market is willing to pay for ethylene, i.e., propane's alternate value in petrochemicals. To calculate this value, we must first look to the petrochemical industry to see what feedstocks are being most frequently used. Ethylene units built since 1970 have been predominately of the "liquid feed" type using naphtha or more frequently light gas oil as feedstock.

In Figure 5 the required sales price for ethylene is shown with parameters of feedstock, and whether from new or existing plants. This figure shows that relative feedstock costs caused gas oil to become the preferred feedstock for new ethylene plants in 1976. Since that time ethane has become progressively less favorable in the general case. Special considerations, such as limited markets for the many by-products of gas oil cracking still cause ethane feed plants to be given serious consideration when adequate ethane supplies are available. One such plant is presently under construction by Phillips Petroleum Company.

Nevertheless it is evident from Figure 5 that new steam crackers using ethane as a feedstock will not be generally economic on the Gulf Coast while, at the same time, steam crackers which already use ethane as a feed will remain competitive. Using the minimum price for ethylene and allowing full capital recovery for new plant capacity (1970 and 1975 are ethane-based while 1980 to 1990 are gas oil-based), we can impute the maximum price which a petrochemical manufacturer would pay for propane in these years.

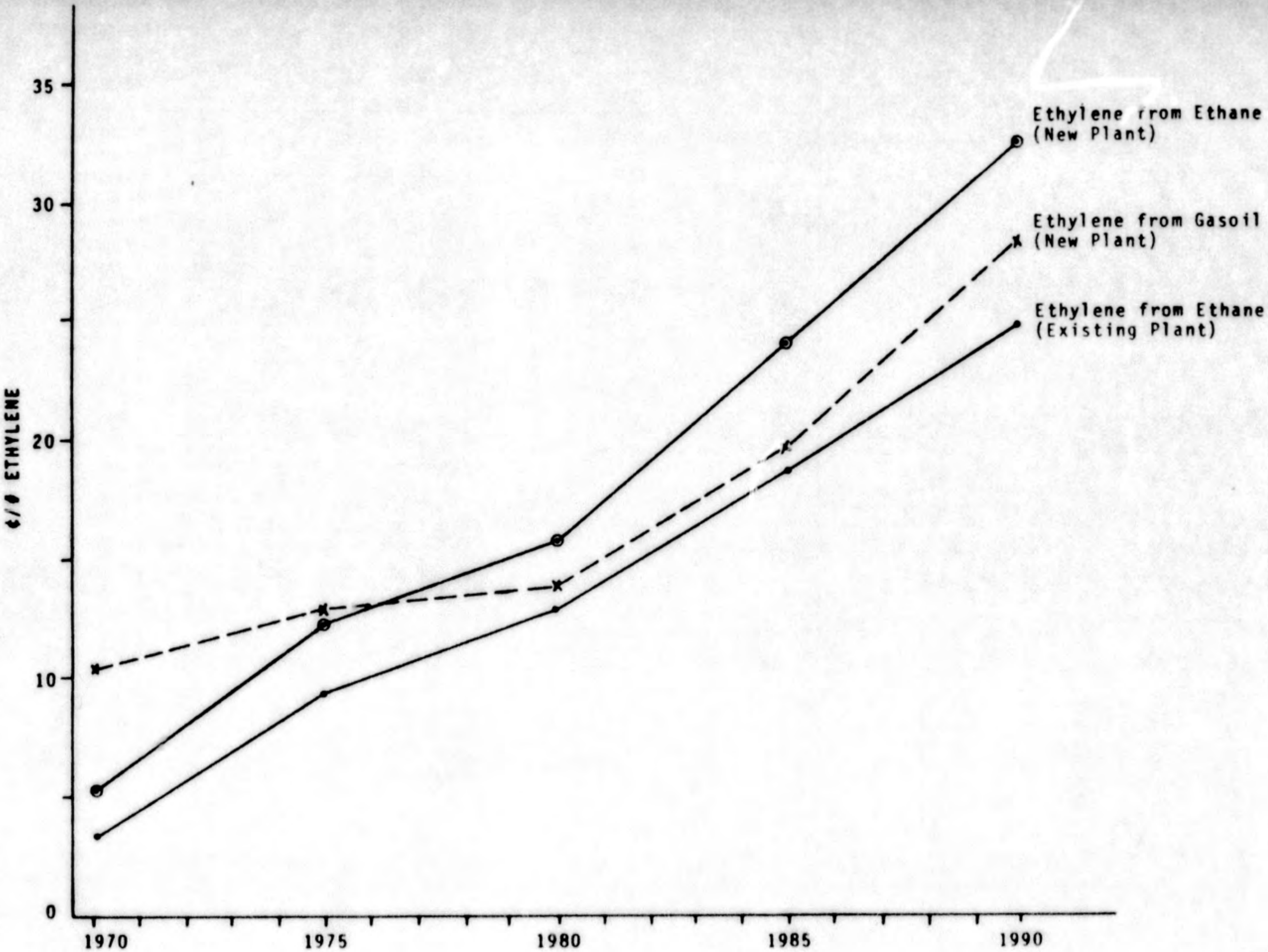

Figure 5. Ethylene from Ethane and Gasoil

Table 3 summarizes the cost of LPG extracted from "new" natural gas and the values of each product is their best alternate use to fuel. Clearly the future value of "new" gas will be too high for the extraction of gas liquids to be generally economical.

TABLE 3

DIFFERENTIAL BETWEEN COST AND ALTERNATE VALUE AS SEGREGATED MATERIAL

(¢/gal)

	1975	1980	1985	1990
Propane				
Fuel Value plus Extraction Costs	23.70	32.36	47.44	72.14
Alternate Value	22.44	26.98	38.42	55.46
Difference	1.26	5.38	9.03	16.68
Butane				
Fuel Value plus Extraction Costs	27.23	37.18	54.50	82.89
Alternate Value	18.98	26.17	45.17	61.60
Difference	8.25	11.01	9.33	21.29
C5 and Heavier				
Fuel Value plus Extraction Costs	30.95	42.25	61.92	94.20
Alternate Value	22.74	29.93	47.79	71.31
Difference	8.21	12.32	14.13	22.89

BACKGROUND: Factors Affecting NGL Values in Alaska

We contemplate that Alaska will experience somewhat different economic conditions affecting the value of natural gas and gas liquids. The cost of transporting Alaska's hydrocarbons to market is extraordinarily high. The values of hydrocarbons for in-state use are distorted by this cost in comparison to values in the major U.S. petrochemical producing areas.

The state is familiar with this distortion of values from the experience of having its crude oil royalties substantially reduced when Alaskan crude must be transported to Gulf Coast refineries. In round figures, the wellhead value of Prudhoe Bay crude oil is 60 percent of its average delivered U.S. refinery value. If the gas pipeline were to be built and the regulated wellhead price of $1.63/MMBTU were realized by the producers, this would represent only about 30 percent of the market price to distributors in the lower 48 states. If marketplace economics were to prevail, rather than economics dictated by governmental regulation, then the wellhead value of Prudhoe Bay gas would be negative since the combined costs of conditioning and transportation are greater than the price of alternate gas supplies such as Mexican or Canadian gas.

The use of natural gas liquids for petrochemical manufacture in Alaska will be economically feasible only if these materials have an in-state value substantially lower than world prices. Some petrochemical cost figures will illustrate this point. Cracking of LPG at the U.S. Gulf Coast incurs a cost structure as shown in the following table.

Cost Item	Percent of Total Cost
LPG Feedstock Costs	46.4
Controllable Costs	23.6
Fixed Costs	5.7
Capital Recovery Costs	24.2
	100.0

If capital costs in Alaska must be escalated 40 percent over U.S. Gulf Coast costs, then the feedstock price must drop 21 percent to offset this escalation. If the proper escalation factor is 100 percent, then feedstock prices must drop 52 percent.

The Alaska location is removed from other U.S. markets for petrochemicals by a product transportation cost disadvantage of about 1-2 cents per pound. This amounts to around 4 percent of the revenue from potential petrochemical products such as plastics. If this adjustment were applied to the situation where Alaskan construction costs were shown to be 40 percent higher than U.S. Gulf Coast, the combined construction and product transportation cost effects would be to reduce LPG feedstock values by 30 percent. If the construction cost escalation factor were 100 percent, the LPG feedstock value would drop 61 percent.

The foregoing calculations apply to feedstock values at the plant site. In Alaska it is contemplated that separation and transportation costs from Prudhoe Bay to tidewater would amount to about $1.10/MMBTU for natural gas liquids. In the earlier Bonner & Moore study on "Utilization of Royalty Gas" the value of ethane at a tidewater petrochemical plant site was $2.10/MMBTU. That study used a capital cost escalation factor of 40 percent so we would deduce that the $2.10

should be 70 percent of the "lower 48 value". This value would then calculate to \$3.00/MMBTU. Referring to the earlier Table 3 (page 21) we see that ethane priced at a "new gas" BTU value plus extraction costs is, indeed, \$3.00/MMBTU in 1978/79.

While these two independent determinations of ethane value should be essentially identical, this discussion may more readily illustrate the factors and their size magnitude that affect gas liquids values as petrochemical feedstocks in Alaska.

The most favorable economic circumstances for utilizing gas liquids in the state involve recovering and transporting the maximum quantity of these materials. This produces the most favorable economies of scale. However, even a very large initial petrochemical project in Alaska can consume only about 15-20 percent of the gas liquids that must be recovered if the logistics costs are to be kept to a feasibly low level. Therefore, 80-85 percent of the gas liquids must be sold in the LPG market. This volume of about 140,000 to 150,000 barrels per day is sufficiently large that no quick judgment can be made about the net market value of these materials in Alaska.

The earlier economic calculations assume that excess gas liquids, over petrochemical requirements, had the same value as ethane, namely \$2.10/MMBTU. Current LPG market prices suggest that this value is appropriate. However, the prospects for higher values in later years is reasonably good. The main question regarding LPG sales is how and whether a market can be found for this quantity of material.

Another occurrence that bears on the feasibility of petrochemical development in Alaska is the increase in world prices for petrochemical feeds. The recent OPEC crude price increase of 14.5 percent, by the end of 1979, plus continuing increases in domestic crude prices should add about $0.40/MMBTU to ethane (and LPG) values as petrochemical feeds in 1980. Thus, the calculated Alaska tidewater value of $2.10/MMBTU should increase to around $2.50/MMBTU in that year.

STATE
of ALASKA

MEMORANDUM

TO: Charles R. Webber
Commissioner

Thru: Richard H. Eakins, Director
Division of Economic Enterprise

DATE:

FILE NO:

TELEPHONE NO:

FROM: David M. Reaume, Principal Economist
Division of Economic Enterprise DMR

SUBJECT: Bonner and Moore Report of January 10, 1979

On January 10, 1979 Bonner and Moore Associates, Incorporated, presented to the Alaska Royalty Oil and Gas Development Advisory Board a study of the economic feasibility of in-state processing of Prudhoe Bay gas liquids. The study's principal conclusion was that in-state processing might be economically feasible if the Alcan natural gas pipeline is not built, and if the State of Alaska takes steps to lower the costs of production to the processor. Bonner and Moore has recommended that a $225,000 engineering cost study be done for one piece of the petrochemical project -- a proposed Prudhoe Bay to tidewater, eighteen inch, gas liquids pipeline. The Royalty Oil and Gas Advisory Board has concurred in this proposal.

I believe that Bonner and Moore's recommended study is premature and inadequately justified. My two primary reasons for believing this are:

(1) Bonner and Moore's analysis is largely confined to one year, 1978. This may allow them to reach an overly optimistic conclusion as to the economic potential for in-state processing. In particular, in concentrating on present market conditions they appear to have completely ignored the Mexicans. Recently, the Mexican government has announced that it will offer a 30 percent discount on raw materials to encourage large scale petrochemical plant construction on both the Mexican Gulf Coast and the Mexican West Coast (Business Week, January 15, 1979). If they proceed, the market for basic petrochemicals such as ethylene and propylene may weaken further throughout the next decade.

(2) Bonner and Moore's formal profitability calculations depend upon a capital cost for gas conditioning of $310 million. While I have not attempted an independent estimate, I simply note that Bonner and Moore arrive at this figure as the pro rata share of a $1.5 to $2.0 billion conditioning plant designed for Alcan. Nowhere in their report do they show the effect on the project's economics of the higher conditioning costs which would be incurred if the Alcan pipeline was not built. Indeed, the $1.02/MMBTU price they estimate an in-state petrochemical operation could afford to pay for LPG at the wellhead, assumes that Alcan is built. If Alcan is not built, conditioning costs of $1 billion have been suggested verbally by Mr. Moore. At these costs, I estimate that the project could afford to pay only $0.60/MMBTU for LPG at the wellhead (if I grant Bonner and Moore the remainder of their assumptions). While the producers might sell at this price if they have no alternative, they will not move quickly to do so.

My remaining reasons are:

(3) Bonner and Moore's use of a single year to judge the profitability of in-state processing causes them to ignore the difference between (i) the return on equity per year (part of which should be thought of as a principal payment on equity invested), and (ii) the real yield on equity over the life of the investment. At the twelve percent per year return on equity suggested by Bonner and Moore (the industry average for 1977 and 1978), it would take approximately eighteen years of capacity operation just to earn back the initial investment (assuming a 6.5 percent annual rate of inflation). If the Prudhoe field can support a twenty-five year flow of LPG at the project's proposed capacity daily rate of flow, Bonner and Moore's annual return of twelve percent of equity translates into an expected real annual average yield over the life of the project of only two percent. In my opinion, given the market risk, this is too low an expected return to justify State participation. The availability of additional feedstocks from, say, the Beaufort, would improve prospects.

(4) Bonner and Moore's $711 million cost estimate for construction of the proposed 18 inch LPG pipeline from Prudhoe Bay to Kenai (via Fairbanks) may be optimistic. Dependent upon a variety of assumptions, such as the extent of worker overtime and the degree of "learning" since TAPS, likely estimates, in 1978 dollars, fall in the range of $700 million to $1.2 billion. (Based on construction cost data published in the August 14, 1978 Oil and Gas Journal.) A more detailed discussion of my own pipeline cost estimates is attached.

(5) A near classic irrelevancy is the statement that "in-state use of gas liquids (may) provide the greatest net benefit to the State." (Bonner and Moore Report, p.3) If the State must invest to realize this net benefit, the proper criteria is net benefit relative to that achievable from the best alternative investment (tourism, fishing, hardrock mining, etc.). I am concerned that Bonner and Moore has missed this point, because they state (p. 3 of their report) that their recommendation is based, in part, on the belief that in-state processing will provide the greatest net benefit from the gas liquids.

(6) It is not clear to me that the results of an engineering cost study would change matters much. According to Bonner and Moore's calculations, the $711 million pipeline cost estimate translates into about 35.4¢ per MMBTU over the life of the project. If they were low by a factor of two, the effect would be to raise the 35.4¢ to about 71¢ per MMBTU. Since they have said that the gas liquids project cannot go unless Alcan fails, the effect of their being too low is to reduce the wellhead price payable by the project by 35.4¢ per MMBTU, say, from Bonner and Moore's $1.02/MMBTU to $0.66/MMBTU. If the gas liquids producers' only alternative use of LPG is field fuel, we may simply end up negotiating wellhead price in a lower range.

Furthermore, given our experience with the TAPS cost estimates, how much confidence would we have in the results of the engineering cost study? Would it really reduce our uncertainty that much?

It is difficult to understand the need to rush ahead with a $225,000 cost study that may be partially or totally obsolete before any further steps can be taken. Suppose the study takes six months to complete and confirms Mr. Moore's $711 million estimate? What have we gained? A possible six months? The fact, noted above, that at twelve percent per year it would take eighteen years just to recover the initial investment, strongly suggests that, even if an optimistic pipeline cost estimate is justified, the State should first determine the availability of feedstocks in addition to those from Prudhoe Bay, before making any large financial commitments. I believe $225,000 is a large commitment.

While I agree with Bonner and Moore's conclusion that in-state processing may be feasible if Alcan is not built, I disagree with their recommendation to immediately fund a pipeline cost study. Admittedly, one has feelings of helplessness and frustration when one contemplates the possibility that Prudhoe Bay gas may go unused (no Alcan, no processing). However, it is precisely at such times that one must be most careful to guard against doing "something," just to be doing something.

Assuming Alcan is not built and that the State does not wish to extend large subsidies to a new petrochemical venture (would not Alpetco demand equal treatment?), the fate of a gas liquids venture is in the hands of the North Slope producers. Until they decide to sell their share of Prudhoe Bay gas liquids at a price that makes in-state processing feasible, we have no project. If we must do something, I suggest we begin to explore this question with the producers.

PIPELINE COST ESTIMATE

The method used here makes use of historical construction cost information published in the August 14, 1978 Oil and Gas Journal to develop an historical Alaska markup factor. This factor is then applied to the average per mile cost of constructing an 18 inch onshore pipeline in the "Lower 48" in 1978 to obtain an estimate in 1978 dollars of the per mile cost of constructing an 18 inch onshore pipeline in Alaska. Multiplication by 800 (800 miles) yields my best estimate of the total cost of the Prudhoe Bay to Kenai gas liquids line -- $1.053 billion. Alternative estimates are also developed.

Alaska Markup Factor

The largest diameter pipelines for which cost figures are given in the August Oil and Gas Journal survey are two 42 inch cru[illegible] oil pipelines laid in Michigan in 1974. Their respective per mile costs were $487,782 and $558,569 for an average of $523,160. To account for cost increases for larger diameter pipe the average per mile cost of a 48 inch pipeline constructed in the "Lower 48" in 1974 is taken to be $600,000.

The Oil and Gas Journal's pipeline construction cost index rose sixteen percent between 1974 and the middle of the TAPS construction period. Therefore, I take $600,000 x 1.16, or $696,000 to be the average per mile cost of a 48 inch pipeline in the "Lower 48" during the TAPS construction period.

The Journal estimates that TAPS cost \$8.7 billion, excluding interest on borrowed capital. Subtracting (1) the capital cost of delivery facilities (\$1.444 billion primarily for Valdez), (2) pumping station equipment (\$617.7 million), (3) the haul road (\$200 million), (4) all other buildings (\$243.6 million), and (5) thirty percent of the cost of laying the pipe to account for excessive overtime (\$1.749 billion) leaves an adjusted TAPS cost of \$4.446 billion. It should be noted that this figure includes the \$165.3 million cost of line pipe, an item priced considerably below the average 1975-1977 cost because of prepurchase.

Given the \$4.446 billion total adjusted TAPS cost, the per mile cost in millions is then \$4446/800, or \$5.558 million.

The Alaska markup factor is then AMU where

$$\begin{aligned} AMU &= \text{TAPS cost per mile/Lower 48 cost per mile} \\ &= 5.558/.696 \\ &= 7.986 \end{aligned}$$

Cost of 18 inch Pipeline

The average per mile cost of an 18 inch pipeline in the Lower 48 is calculated as the average of the Journal's reported 1978 costs for 16 inch and 20 inch pipelines, since there were no numbers reported for 18 inch pipelines, per se.

This procedure yields \$164,777 as the average 1978 per mile cost of an 18 inch pipeline laid onshore in the "Lower 48." Multiplying this by the Alaska markup factor of 7.986 yields \$1,315,909 as the per mile cost of an 18 inch pipeline laid onshore in Alaska in 1978. The estimated total cost of the Prudhoe to Kenai LPG line in 1978 dollars is then \$1,315,909 x 800, or \$1.053 billion.

If one assumes a thirty-three percent reduction from this figure for "learning," or further reductions in overtime than those assumed above, one obtains Bonner and Moore's \$711 million estimate.

<u>Point of note</u>

The higher the estimated cost of building a 48 inch pipeline in the "Lower 48," the lower AMU and, thus, the lower my estimated cost of the LPG pipeline. I have taken \$696,000 to be the "Lower 48" per mile cost of a 48 inch pipeline constructed during the TAPS period. If we multiply the original (1970-1971) cost estimates given for TAPS (approximately \$1.2 million per mile) by the ratio of our adjusted TAPS cost, \$4.446 billion, to the total cost, \$8.700 billion, we get \$612,000, as the original (adjusted) per mile estimate for TAPS.

The original cost estimates for TAPS were too low for a number of reasons. One reason was unexpected inflation. In 1971 inflation was widely expected to proceed at about a two to three percent long-term average rate. Between 1971 and 1976 the actual annual average increase in the GNP deflator was about seven percent. A five percentage point per year excess of actual inflation over 1971 expectations yields a five year cumulative compounded excess of 27.6 percent. If the $612,000 original (adjusted) per mile TAPS cost is increased by 27.6 percent, we get a figure of $780,912. Adjusting for the full annual seven percent inflation from 1971 to 1976 yields an estimate of $858,326 per mile.

Since $780,912 is only 12.2 percent greater than my $696,000 "Lower 48" cost per mile, and $858,362 only 23.3 percent greater, my $696,000 estimate may not be too small. The suggestion is that $1.053 billion may not be an unreasonable estimate of the cost of the Prudhoe-Kenai LPG pipeline.

Construction costs in Alaska are often said to be about forty percent higher than in the "Lower 48." Replacing the $696,000 estimate of "Lower 48" costs for a 48 inch pipeline by $613,116 (1.4 x 613,116 = 858362) and recalculating AMU, yields an estimate for the Prudhoe-Kenai pipeline of $1.2 billion.

Based on the analysis presented here it appears that the proposed Prudhoe-Kenai pipeline can be reasonably estimated to cost anywhere from $700 million to $1.2 billion in 1978 dollars dependent upon one's assumptions. The Bonner and Moore estimate of $710.6 million is at the low end of this range.

DMR/val3/11

Bonner & Moore Associates, Inc.
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(713) 522-6800 • TWX: 910 881 2542

March 12, 1979

Mr. Don Wold
Executive Director
Alaska Royalty Oil & Gas
Development Advisory Board
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Dear Don:

Mr. David M. Reaume of the Department of Commerce has issued an analysis of the report and recommendations presented by Bonner & Moore to the Royalty Board on February 1, 1979. Many of his comments are thoughtful and properly germane to the issue of instate petrochemical development. Certain other of his comments appear to be inconsistent with supplemental information that was verbally presented to the Board along with the report contents. Since Mr. Reaume was not at that presentation this inconsistency is certainly understandable.

In this letter I will address each of the points raised by Dave and attempt to provide satisfactory answers to the difficulties he cites.

1) Impact of Future Petrochemical Developments In Mexico

I don't consider that major petrochemical developments in Mexico will be a factor in world petrochemical supply for many years. Mexico will not find it desirable to finance such plants at the expense of the costly oil production programs they envisage. Furthermore, Mexico maintains strong foreign investment curbs that major petrochemical producers will continue to find too restrictive. Finally, the overall security of foreign investment in nations having the potential for socialist or Marxist revolutions is of serious concern. Mexico certainly must be regarded as having the potential for such developments even though the government has been a model of stability in Latin America.

Dave criticizes the use of single year economics to project future market developments. Actually the Bonner & Moore report makes no pretense of including any petrochemical market analysis. Use of 1978 cost and price figures is only intended to quantify the various elements that determine the overall economics of petrochemical production. However, the fallout from Iran's revolutionary explosion has included the effect of dramatically increasing petrochemical prices and exports from the U. S. . I have stated repeatedly that petrochemical economics are cyclical. The high prices that will prevail over the next several months will probably be no more representative of a long term average than the very low prices of the past 1-2 years.

2) Impact of Gas Conditioning Costs on Gas Liquids Values

The points raised here are valid. Recovery of the gas liquids at Prudhoe Bay, in the absence of an Alcan gas line, will undoubtedly cost more than was indicated in our earlier study for the Department of Revenue. Furthermore, the actual cost can be determined only after a fairly complete design and engineering study. If these liquids are to be kept in-state the producers must be induced to undertake such a study promptly.

3) Impact of Future Cost Inflation on Petrochemical Investment Return

Dave's concern here probably stems from an unfamiliarity with petrochemical contracts. While he properly noted that inflation will reduce the real return on investment because the plant replacement cost rises, this is true only if product market prices don't inflate in amounts that cover the inflation of new plant construction costs. Petrochemical suppliers do not contract for long term fixed prices. The typical sales contract calls for "price re-openers" on a quarterly basis. If the market demand grows for petrochemicals then market prices must rise to support the cost of new plant investment. Old plants, therefore, become progressively more profitable, although, as Dave points out, some of that profitability is illusory because depreciation reserves are too low to reflect inflationary effects.

4) Adequacy of Bonner & Moore's Earlier Pipeline Cost Estimate

The earlier cost estimates were prepared by individuals experienced in the Alaskan construction environment. However, they were the roughest of approximations since so little time was devoted to their preparation. Better estimates must await more detailed site study and engineering.

5) Definition of "Greatest Net Benefit"

These comments are well taken since Bonner & Moore clearly has not considered any alternate uses for state capital spending. However, the term "greatest net benefit" seems to be used with regard to in-kind oil and gas royalty in a similarly inexact manner. We simply adopted the same terminology but it is certainly too sweeping in its implication. If we have indeed authored an irrelevancy, I suppose it is consoling to have achieved near classic proportions.

6) Value of a More Accurate Pipeline Cost Estimate

Dave's comments on this point show that Bonner & Moore's whole strategy for stimulating petrochemical development from gas liquids is not clear. Our recommendation to the Board was two-fold. One recommendation was to put together an engineering design, cost estimate, and financing package of sufficient substance to support the development of pipeline transportation costs for presentation to prospective shippers. The second recommendation was to determine how a pipeline operating company should be organized, at least in an interim promotional status. This company would begin to promote the use of a gas liquids pipeline to producers and prospective purchases of gas liquids as soon as the investment and cost study were complete. The premise is that if the state makes a credible enough representation about sponsoring the future construction of a pipeline, serious consideration will be given to in-state petrochemical investments. If the second recommendation is not followed then Dave's reservations about the value of an engineering design and cost estimate are well taken.

I think it is most timely to proceed on this matter. The situation in Iran has made petrochemical producers all over the world re-evaluate their raw material, marketing, and investment strategies. The elements favoring Alaska as a location for petrochemical plants are currently reinforced in their importance by world events.

I hope these comments will alleviate most of David Reaume's concerns. The time and attention that has been devoted to his analysis is most appreciated.

Very truly yours,

Joe F. Moore

Joe F. Moore
President

JFM:me

02-001B (Rev. 10/76)

STATE
of ALASKA

MEMORANDUM

TO: Richard Eakins
Director

DATE: March 29, 1979

FILE NO:

TELEPHONE NO:

FROM: David Reaume
Principal Economist

SUBJECT: Bonner & Moore
Letter of
March 12, 1979

Joe Moore's response to my comments pretty much leaves them where they stand. We obviously disagree on the Mexican potential. (For my part, I am not sure why a socialist revolution in Mexico would prevent Mexico from becoming a world leader in petrochemicals, as suggested by Mr. Moore, unless the revolution lasted very many years. They obviously do not need private capital and can purchase the technology.)

If I may paraphrase his response, it appears to be "Dr. Reaume is largely correct, but you should proceed with my suggestion anyway." I am content to leave it at that (having agreed to disagree on Mexico) and let State decision-makers decide whose advice they wish to follow, except for one point.

Mr. Moore suggests that allowance for rising petrochemical prices invalidates my statement that, at an annual rate of return of 12.0 percent, it would take over eighteen years just to get back the equity investment. I am afraid I must disagree. A constant 12 percent rate of return could only be achieved, in the face of rising costs, if product prices also rise. In order to shorten the payback period to less than eighteen years, Mr. Moore must show that the rate of return on equity rises over time. I welcome such an attempt on his part. My whole point is that Mr. Moore needs to back up his assertions, not just re-echo them.

In my opinion, it takes more in the way of concrete analysis to justify his proposed strategy.

DR/mh4/12

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

PRUDHOE BAY NATURAL GAS LIQUIDS,
THE ALASKA HIGHWAY GAS PIPELINE,
AND PETROCHEMICAL DEVELOPMENT IN ALASKA

A Review of the November 1, 1979 Report,

PROMOTION AND DEVELOPMENT

OF THE

PETROCHEMICAL INDUSTRY IN ALASKA

by Bonner & Moore Associates, Inc.

to the

Alaska Department of Natural Resources

Royalty Oil and Gas Development Advisory Board

By CONNIE C. BARLOW

ARLON R. TUSSING AND ASSOCIATES, INC.

20 January, 1980

CONTENTS

<u>Inquiries</u> about this review should be addressed to:

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FOREWORD BY ARLON R. TUSSING

This review began as a private memorandum Connie Barlow wrote at my request for members of our organization and a few professional colleagues. In it she summarized the November 1979 report of Bonner & Moore Associates, Inc. (B&M) to the State of Alaska on the outlook for establishing a new in-state petrochemicals industry based upon natural gas liquids from Prudhoe Bay. She also related B&M's findings to the most controversial current policy issues regarding the disposition of the various North Slope hydrocarbons.

Ms. Barlow's reading of B&M was in startling contrast to the things we had heard about their report. Instead of setting out a strategy for assuring the feasibility of a gas liquids-based petrochemical facility, their analyses seemed to add up to a powerful case against the very development strategy they describe.

The issues involved are of great importance to Alaska, but they are also exceedingly complicated. The B&M report, moreover, is often obscurely written and many --- if not most --- of its key assumptions and sources are unstated. All these considerations argued for a wider distribution of Ms. Barlow's review; but they also demanded an especially careful verification of her interpretation of B&M, and careful editing of any public version.

We sent drafts of this paper to B&M for comment, and also to their subcontractor Birch, Horton, Bittner, and Monroe; to the major Prudhoe Bay gas producers; to Northwest Alaskan Pipeline Company; and to a number of state and federal officials concerned with North Slope oil and gas production, the gas pipeline, and petrochemicals development.

The time my cover letter allowed for response to the review draft did not allow all of these parties to scrutinize it with the thoroughness the review's author gave the B&M report. We did, nevertheless, receive expert and helpful comments from several industry and governmental sources. A group of executives and engineers from one of the producing companies deserves special thanks for spending a day with Ms. Barlow and me, helping to clarify our understanding of the relationships among a number of physical and engineering principles, Prudhoe Bay hydrocarbon balances, and the Parsons design for a North Slope gas conditioning facility.

The basic understandings in Ms. Barlow's first memorandum stood up very well under this intensive review process. We have changed a few numbers and made some editorial improvements, but the thrust of the original review remains intact: B&M do not state a case in favor of gas liquids-based petrochemical manufacturing in Alaska, but rather a case against it.

Neither the B&M report nor the Barlow review is the last word on this issue. Another strategy and another analysis may well demonstrate the feasibility of some kind of petrochemicals venture in the state --- but B&M have not yet presented such a strategy or analysis.

This review is offered to Alaskans as a public service of Arlon R. Tussing and Associates, Inc. It was not produced under contract to, or with funding from, the state of Alaska or any other interested party.

I. INTRODUCTION AND SUMMARY

Bonner & Moore Associates, Inc. (B&M) in November 1979 submitted a report titled Promotion and Development of the Petrochemical Industry in Alaska to the Alaska Department of Natural Resources, Royalty Oil and Gas Development Advisory Board. In the coming year, state officials, legislators, and individual Alaskans will surely cite this study in support of or opposition to proposals for state action to create a local petrochemicals industry using natural gas liquids from Prudhoe Bay.

Unfortunately, the B&M report does not set out its major findings clearly and systematically in any one place, nor does it relate these findings explicitly to the policy issues that have caused the greatest concern or controversy among various Alaskan groups, the North Slope gas producers, the gas pipeline sponsors, and federal agencies. Even more unfortunately, B&M's executive summary will badly mislead any reader who does not read the entire report carefully and critically.

For these reasons, this review is designed, in part, to point out the policy significance of B&M's analyses. We have generally chosen to overlook any disagreements we may have with the report's assumptions and analytical methods --- because even if B&M's calculations are accepted at face value, their logical implications dramatically contradict the executive summary's "affirmative conclusion that a project can be developed in Alaska that would produce ethylene-based petrochemicals for the Pacific market with acceptable profitablity".[emphasis added]

Our review also examines the effects of the B&M scenario on various parties with an interest in the Alaska Highway gas pipeline. While an analysis of these impacts was not clearly part of B&M's study mandate, the costs imposed on other interests by removing natural gas liquids from the sales gas may well be tossed back into the lap of the party that receives the liquids. Some of these effects are substantial, and therefore demand close attention from policy-makers who would look to B&M for practical guidance.

Some of the most important implications that this review draws from B&M's analysis are the following:

*** The B&M scenario requires a change in the gas conditioning process and field fuel design at Prudhoe Bay. Not only would this change negate the Parsons' design and require a whole new conditioning study, but the end result may substantially raise the cost of gas conditioning.

*** Removing 107,000 barrels of natural gas liquids per day from the hydrocarbon stream destined for the Alaska Highway gas pipeline would increase the unit transportation costs of the remaining gas by about 16 percent. The heating value of the gas stream would fall from 1106 to 1050 (gross) BTU per cubic foot.

*** As much as one-fifth of the total energy available to the nation from Prudhoe Bay natural gas could well be lost if a project like that suggested by B&M is put into effect.

*** In order to secure the volume of gas liquids required by the B&M strategy, Alaska could earmark all of its royalty gas liquids, and swap all of its royalty gas (methane) for gas liquids owned by the producers; but the project would still be substantially short of its required volumes.

*** Unless something happens to cause a radical improvement in the economics of the petrochemicals venture described by B&M, their own analysis indicates that it can not operate profitably and pay the state of Alaska anything at all for the ethane it requires as feedstock. In B&M's base case the state would be required to subsidize the project by the equivalent of at least 36 percent (63 cents per MMBTU in 1979 dollars) of its entire Prudhoe Bay royalty gas income.

II. DESCRIPTION OF THE PROPOSED PROJECT

The Bonner and Moore Associates, Inc. (B&M) report, Promotion and Development of the Petrochemical Industry in Alaska, considers the logistics and economics of using North Slope natural gas liquids as feedstocks for a new petrochemicals manufacturing plant to be built in Alaska. In order to perform a detailed analysis the report "creates a 'for instance' project embodying generally conservative premises . . ."[1] The B&M strategy entails:

*** construction of a natural-gas-liquids pipeline from Prudhoe Bay to Cook Inlet,

*** to carry roughly 25 percent (25 thousand barrels per day) of the ethane (C_2) produced from the Prudhoe Bay reservoir,

*** for use as feedstock in a world-scale petrochemicals manufacturing plant near Kenai that would produce about 1 billion pounds of ethylene per year,

*** which the plant would process further into four basic liquid petrochemicals --- low- and high-density polyethylene, ethylene dichloride, and vinyl chloride,

*** for export to Japan, where final processing would take place.

Incidental to the transportation of ethane and manufacture of petrochemicals, B & M propose that:

*** the natural gas liquids pipeline carry almost all of the propane (C_3) and butanes (C_4) separated from the methane (C_1) during natural gas conditioning,

----

1) Joe Moore, letter to Tussing [January 4, 1980].

*** for export as LPG (liquefied petroleum gas) into world markets

The functions of these latter activities, which are not part of the petrochemical operation in itself, are:

*** to provide a greater throughput volume for the natural-gas-liquids pipeline, thus reducing transport costs for ethane, and possibly

*** to cushion petrochemical marketing risks with profits from LPG sales.

III. IMPACT OF THE PROJECT ON NORTH SLOPE OPERATIONS

The B & M report states that its petrochemical development strategy would require two modifications in the present plans for gas processing and conditioning on the North Slope: (1) addition of an ethane extraction facility, and (2) a change in the fuel mix for field operations.

The first modification adds a facility on the North Slope to extract 25 thousand barrels of ethane per day from the roughly 60 thousand barrels that would remain in the "sales gas" stream after conditioning.[2] Quite rightly, the B & M report assumes that the costs of ethane extraction would be borne entirely by the liquids purchaser(s), and thus should impose no direct cost burdens either on the gas producers or on the purchasers of sales gas shipped through the Alaska Highway gas pipeline.

The report, however, does not acknowledge the full impacts of its petrochemical strategy on North Slope fuel availability and overall conditioning design. The conditioning plan now under consideration (the Ralph M. Parsons study) anticipates that the ethane-CO_2 "waste-gas" mixture generated during the conditioning process can be used for fuel if it is further enriched by adding more than half of the propane that the fractionation plant will make available.

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2) While shipping all 60 thousand barrels per day of available ethane through the gas liquids line could further reduce unit costs of transportation, the report indicates that the cost of high pressure facilities for storage of ethane in liquid form would offset any transportation cost savings. [p. 7-1]

The B & M strategy, however, calls for shipping <u>all</u> of the separated propane through the gas-liquids pipeline. (See Table I.) Accordingly, the report assumes that "field gas" will be used as fuel instead. [p. 3-9] (We assume that field gas is the methane-rich raw gas, less the heavier NGLs and water.)

This change in fuel composition inevitably demands a change in design for the entire conditioning process: Unless propane is available, there is no practical way to enrich the ethane-CO_2 waste gas mixture; hence, a conditioning process that fully removes all hydrocarbons from the CO_2 stream would have to be used.

<u>Such a modification would require a completely new engineering study and might well result in higher overall gas conditioning costs</u>. The B & M report does not acknowledge any such additional costs, and consequently, makes no provision for allocating them to the responsible party --- that is, the petrochemical operation.

IV. EFFECTS OF THE PROJECT ON NORTH SLOPE GAS PURCHASERS AND ON UNITED STATES NET ENERGY SUPPLY

If almost half the ethane and all of the propane and butanes were removed from the sales gas stream shipped through the Alaska Highway gas pipeline, the total caloric value of the gas would be reduced substantially. Gas purchasers would suffer both the effects of (1) a leaner gas stream (fewer BTU per MCF), and (2) higher transportation costs per unit of gas. Export of the petrochemicals from the United States, and possibly of the LPGs as well, would result in (3) a net reduction in domestic U.S. energy supply, which would have to be offset by an increase in crude oil imports.

Table I shows the approximate volumes and BTU content of the hydrocarbons (1) fed into the conditioning plant, (2) consumed as fuel for gas production and conditioning, and (3) available for shipment from the North Slope through the TAPS oil pipeline, the Alaska Highway gas pipeline, or some other transportation facility like the gas liquids pipeline proposed by B&M.

Table II shows how the B & M strategy for petrochemical development would affect the composition and volume of the sales gas, and thereby its market quality and unit costs of transportation through the gas pipeline.

B & M's scenario would reduce the gross heating value of the sales gas from 1106 to 1050 BTU per cubic foot. While 1050 may approach the minimum BTU richness specifications for Lower 48 pipelines, this heating value reduction in itself poses no real threat to gas marketability.

However, the B & M scenario would reduce the total energy content of the sales gas by about 386 billion BTU per day, or 17 percent. The fixed costs and total costs per BTU for pipeline transportation would thus increase by about 20 percent and 16 percent respectively.[3] This is a significant increase, and federal regulators may well be moved to consider allocating those cost increases to the responsible party -- the liquids purchaser(s).

Of the total energy removed from the gas pipeline, 68.5 billion BTU per day in the form of ethane would be converted into non-fuel petrochemicals for export to Japan. B & M are vague about LPG markets, but if these liquids too were exported, the entire 386 billion BTU per day would be a net loss of domestic energy to the U.S. economy. To this total must be added fuel for the ethane extractor and the petrochemicals complex. At least part of this demand would be met by hydrocarbons that otherwise would have reached the Lower 48 as natural gas or crude oil. Unfortunately, B & M do not give us figures on the amount of energy these facilities would require.

If chlorine --- a necessary ingredient in two of the four petrochemicals the plant is to produce --- were manufactured in Alaska, both steam and electricity would be needed. Here, we can at least impute energy demand from the B & M report: 60 billion BTU per day.[4] Altogether, it is conceivable that this project might reduce the total volume of Alaska energy available to the United States as natural gas or crude oil more than 500 billion BTU per day --- over one fifth of the energy the gas pipeline would otherwise contribute.

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3) These figures are for the entire pipeline system, excluding Northern Border. An 17 percent reduction in BTU shipments corresponds to a 13 percent reduction in MCF. The result would reduce total compressor fuel use by 23 percent in Alaska and 13 percent in Canada.

4) \$143,200/day @ \$195/ton = 735 tons/day;

755 tons/day @ \$186/t @ \$2.25/MMbtu = 60 billion BTU/day.

V. EXCHANGING STATE ROYALTY METHANE FOR NATURAL GAS LIQUIDS

Under the Prudhoe Bay lease contracts, the state owns a one-eighth royalty interest in each of the two streams of hydrocarbons (oil and gas) produced from the lease, and may elect to take its royalty either in money or in kind. If the state takes its natural gas royalty in kind, it has to take one-eighth of each of the produced hydrocarbons --- methane, ethane, propane, butanes, and pentanes-plus --- in such combinations as they come from the processing and conditioning facilities.

The state's share of NGLs available falls short of the B&M NGL requirements by 328 billion BTU per day. For this reason, state officials are negotiating with the gas producers, and with federal agencies that might have some regulatory jurisdiction over the disposition or pricing of Prudhoe Bay natural gas liquids, for an option to exchange the state's royalty share of the methane for sufficient natural gas liquids to provide feedstocks for an Alaska petrochemicals plant.

Is such an exchange feasible? Specifically, will the state have enough royalty methane to obtain the additional barrels of NGLs in a BTU-for-BTU swap? Table III shows that the state could take its entire royalty share of Prudhoe Bay ethane, propane, butanes, and pentanes in kind, and swap its entire royalty share of methane to the gas producers for additional natural gas liquids, and still be 109 MMCF per day short.

In other words, the state would need to control 50 percent more methane than it owns at Prudhoe Bay in orde to implement the B & M proposal, even if it disavowed any interest in retaining some pipeline gas for residential and commercial consumption in Alaska communities. Unless the petrochemical company were able to buy sufficient gas liquids directly from the producers to make up the deficit, the state would have to do so in its behalf.

VI. FINANCING THE PROPOSED FACILITIES

The B&M proposal requires construction of three separate facilities:

*** A petrochemicals complex on Cook Inlet with a (1979) capital cost of $931 million,

*** A 16-inch natural gas liquids pipeline from Prudhoe Bay to Kenai with a capital cost of about $687.3 million,[5] and

*** An ethane-extraction facility at Prudhoe Bay with a capital cost of about $58 million.[6]

Under both state and federal law, the gas liquids pipeline would have to operate as a common carrier, providing service to all shippers without discrimination, to the limit of its capacity. As a result, the gas liquids pipeline would actually have to be built with a capacity considerably greater than the 107 thousand barrels per day proposed by B&M, in order to assure the petrochemicals plant it would receive 25 thousand daily barrels of ethane every day over the economic life of the facility.[7]

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5) The B&M report does not mention the cost or even the diameter of the proposed gas liquids pipeline. We have therefore used a subcontractor's estimate from B&M's earlier report to the state [State of Alaska --- Utilization of Royalty Gas (January 23, 1978)]: Pipe Line Technology, Inc., State of Alaska Feasibility Study of Pipeline Transportation, Royalty Gas and NGL (January, 1978), p. 49. We inflated the 1977 capital cost figure ($574.5 million) from that report to mid-1979 dollars at the rate of increase in the Oil and Gas Journal's pipeline cost index between 1977 and the first quarter of 1979. [O&GJ, November 19, 1979]

6) Nowhere in B&M's report is there a statement of the ethane facility's capital cost. The cost of extracting 25,000 barrels per day, however, is given as $1.03 per barrel of recovered ethane [p. 6-5]. Our figure of $58 million assumes that the $1.03 is composed entirely of fixed costs (return of and to investment), levelized in equal annual installments over 20 years at a 15 percent rate of return on total capital.

B&M conclude that even if Alaska succeeded in attracting a firm to build, own, and operate a petrochemicals plant in the state --- and engage in LPG marketing on the side --- it is unlikely that this firm would also be willing to bear the financing and ownership burdens of the other two facilities.[8] <u>Hence, the state must either (1) make an additional effort to recruit a firm (or firms) to finance and operate the ethane extraction plant and the liquids line, or (2) take on the burdens of financing these two facilities</u>.

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7) Whenever the total volume of natural gas liquids, LPGs, light refined products such as naphtha and gasoline, and possibly even jet fuel, distillate fuel oil and diesel oil, tendered for shipment exceeded the pipeline's shipping capacity, it would have to acccept shipments by all parties <u>ratably</u>, that is, proportionally to their respective tenders.

   If tariffs on the gas liquids pipeline were to be as low as projected by B&M (less than half the average TAPS tariff), and if a profitable market did exist for North Slope LPGs at Cook Inlet, it is likely that at least some of the producers would seek to ship any of their Prudhoe Bay LPGs (the pentanes-plus, for example) not committed to the petrochemicals firm via the liquids line. If new supplies of LPGs became available from other reservoirs on the North Slope, they might also seek space in the line, while the North Slope topping plant and the North Pole refinery are potential shippers of naphtha or light distillates to the Anchorage area. If the line were designed to carry only 107 MB/d, any of these shipments would displace part of the ethane intended for the petrochemicals plant.

   Neither B&M nor (surprisingly) Birch, Horton, Bittner & Monroe, in their subcontractor report to B&M, <u>Government Controls Affecting Development of an Alaskan Petrochemical Complex using North Slope Natural Gas Liquids Feedstock</u> [August 23, 1979] mentions the common carrier issue.

8) "The total investment costs for a liquids pipeline, extraction equipment, and a petrochemical complex are considered to be too great for a single petrochemical producer to bear, since all these investments are subject to identical market risks and are perhaps two to three times as high as for a petrochemical facility built at an established center." [p. 2-4]

VII. SITING CONSIDERATIONS

Bypassing Fairbanks. While B&M have consistently stated that petrochemical development need not by-pass Fairbanks, it is clear that none of the related facilities absolutely depends upon a Fairbanks location. The scenario chosen by B&M for demonstration purposes, for example, places the exthane extractor in the same location as the Prudhoe Bay gas conditioning and processing facilities, and the petrochemicals complex on Cook Inlet. Hence, Fairbanks would get neither of the facilities that its business and government leaders have so avidly sought.

The report does state, however, that "locating the gas-processing plant at Prudhoe Bay will probably result in higher investment and operating costs than the same facility at Fairbanks." [p. 2-2] B&M do not substantiate this judgment, but they pragmatically suggest that the state gauge the economic feasibility of the liquids project on the basis of the most likely even which, given recent FERC decisions, certainly point to a Prudhoe Bay location for gas conditioning. The report does not address the economics or the practical prospects of locating the petrochemical complex itself in Interior Alaska.

Air quality. The report notes that a petrochemical complex in either Anchorage or the Fairbanks-North Pole area might have difficulties in meeting air-quality standards --- even if natural gas rather than coal were used for plant fuel. While Kenai can probably bear the additional air pollution, federal regulatory standards are not likely to allow both the petrochemical complex and the proposed PAC-Alaska LNG plant to be located there. [p. 4-11][9]

9) Joseph M. Chomski of Birch, Horton, Bittner & Monroe (subcontractors to B&M) has criticized this interpretation of page 4-11, citing language in the Birch et al appendix to B&M's report: "The Kenai area has not used up its air pollutant increment yet, despite several industrial facilities already located in the area. However, there is a proposed LNG facility that could use up the increment and foreclose the petrochemical plant siting option due to air pollutant loading. [letter to Barlow, January 7, 1979 (sic)]" Failing to see any substantive difference between the words of our review draft and the subcontractor's own language quoted above, we have maintained our original wording.

VIII. ECONOMICS OF PETROCHEMICALS MANUFACTURING IN ALASKA

Qualitative outlook. B & M cite two main qualitative factors that might attract a chemical company to Alaska:

1. Relatively stable feedstock prices; more properly, feedstock prices that will rise at a predictable rate, [pp. 2-5 and 8-4], and
2. A large and relatively secure supply of natural gas liquids. [pp. 2-5 and 8-4]

The report cautions, however, that three other factors create special burdens for any prospective Alaska petrochemicals producer:

1. Alaska construction will cost about 1.6 times that of comparable facilities on the U.S. Gulf Coast. [p. 2-4]
2. In order to bring ethane to a Cook Inlet facility, someone must build an ethane extractor at Prudhoe Bay and a gas liquids pipeline the length of Alaska: no prudent company would take on the risks of all three of these investments. [p. 2-4]
3. The total risks of such a project in Alaska are two to three times as high as they would be in an established petrochemicals center. [p. 2-4]

Nevertheless, the B & M report judges that the attractions can be expected to outweigh the special burdens of an Alaska location. Joe Moore, in his January 4 letter, refers to ". . . the obvious and overwhelming economic concern of industry, namely that security of feedstock supply and future feedstock cost escalation are the project planning parameters of greatest importance." The following section examines this contention in further detail.

Quantititative outlook. The B&M report [p. 6-5] calculates the volumes of hydrocarbons required by the Cook Inlet petrochemical complex, and their 1979 dollar prices at the plant entrance, as follows:

	Volume (bbl/day)	Price (¢/gal)	Price (¢/lb)	Total Cost (per day)
Ethane (C_2)	24,713	23.3	7.5	$289,586
Propane (C_3)	57,556	27.9	6.6	674,441
Butanes (C_3)	20,354	31.0	6.5	265,009
Pentanes-plus (C_5+)	4,194	33.6	6.4	59,185

These delivered prices reflect [page 2-3]:

*** $1.75/MMBTU for the Prudhoe Bay gas purchase price.

*** $0.50/MMBTU for CO_2 removal at Prudhoe Bay.

*** $1.03 per barrel for ethane extraction at Prudhoe Bay.

*** $2.94 per barrel for the gas liquids pipeline tariff.

B&M do not reveal how they calculated the costs of ethane extraction or of pipeline transportation for the natural gas liquids, nor the basis for their estimates of petrochemical market values in Japan and on the U.S. West Coast. We, therefore, have no basis for evaluating whether these costs are truly realistic. Nevertheless, even if the values in the report are assumed to be correct, they mean that the cost of ethane delivered to the petrochemicals complex will be too high to permit production of marketable ethane derivatives. For, while B&M calculate the cost of ethane delivered to Cook Inlet at 7.5 cents per pound, the petrochemicals complex could afford to pay only 4.3 cents per pound in order to compete in Japanese markets, and only 4.0 cents to compete on the U.S. West Coast [pp. 8-4 and 8-7].[10]

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10) B&M's projections of maximum affordable ethane prices are those that would meet current 1979 market prices for ethylene derivatives. [Joe Moore, letter to Tussing, January 4, 1980]

The report offers several possibilities for improving this dismal outlook:

First, if the petrochemicals complex owner were willing to accept a rate of return on total investment of only 7.3 percent in place of the 15 percent assumed in the report, Alaska petrochemicals might be competitive in Japan. With a 6.3 percent rate of return, they might be competitive in the United States. [p 8-7] This hope hardly deserves a second look. If the petrochemicals complex were financed with 75 percent debt at 11.5 percent --- the current rate for high-grade industrial bonds --- any return to total investment less than 8.6 percent would yield a negative rate of return to equity.

Second, if the LPGs delivered to Cook Inlet could be sold at a sufficient profit, the cost of ethane delivered to the petrochemicals plant would be reduced from 7.5 to 6.0 cents per pound. [p. C-3] This is still 40 percent higher than B&M's calculation of the maximum ethane price for penetration of the Japanese market, and 50 percent higher than the maximum price for sales within the U.S.

Hope of offsetting losses on the petrochemical operation with profits from LPG sales seems tenuous at best, in view of B&M's earlier observation about the world market outlook for LPGs: "Although the crude oil situation is tight, ample supplies of natural gas liquids exist . . . With this surplus, the Oil and Gas Journal indicates that the world-wide liquefied petroleum gas (LPG) market may offer unsatisfactory prices for exporters." [p. 3-3]. Nevertheless, B&M maintain that the Alaskan LPG sales can operate profitably: "...our projected price for LPG fully takes into account a future surplus of these materials which deprive them of their premium value experienced in recent years." [Joe Moore, letter to Tussing, January 4, 1980]

B&M touch upon two other possibilities for bridging the gap between maximum economic prices for ethane and its cost to the petrochemicals complex. The report mentions a "significant" prospect for reducing transport costs by backhauling vegetable oils from Japan, but does not elaborate further. [p. 5-2]

Alternatively, if no attempt were made to recover plant investment by means of depreciation, to repay principal and pay interest on borrowed capital, or to capture any return on equity, B&M conclude that the petrochemicals complex could afford to pay 6.5 cents per pound for ethane, rather than 4.3 cents [p. 8-4]. Even this "cash-cost" approach leaves the petrochemical facility with feedstock costs 25 percent higher than B&M indicate it could afford to pay.

Moreover, while the investors in <u>existing</u> facilities (say, in Japan) might have no alternative but to accept a "cash cost" price that covers only feedstock and other operating costs, in order to retain customers in a buyers' market, no prudent management would decide to build a <u>new</u> facility if penetration of the market appeared to require "cash-cost" pricing from the outset.

<u>Finally</u>, if feedstock prices were to rise at an annual rate 3.4 percent higher in Japan than in Alaska, the B&M report concludes that ethylene derivatives produced in Alaska might become competetive in five years [p. 8-7]. Unfortunately, B&M do not explain to their readers how a 3.4 percentage-point differential in annual price escalations would bridge the gap between a value of 4.3 cents and a cost of 7.5 cents in five years.

In addition, the report fails to account for the unusual market penetration barriers likely to exist in Japan, in the form of long-term contracts with joint-venture plants in oil-producing nations, protectionist policies on behalf of Japan's domestic petrochemicals industry, or the discounting of prices below "full costs" --- perhaps as low as "cash costs" --- attendant on a quite plausible world oversupply of ethylene.

Even if the report's conclusions with respect to differential feedstock price escalations are valid, the reader must also consider the economic handicaps noted in this review, which the B&M report did NOT take into consideration.[11] All in all, none of the offsetting features that B&M note seems to be substantial, certain, or realistic enough to persuade any prudent management to invest in Alaska petrochemicals development in the manner suggested by the report, or even to consider it seriously.

The need for a subsidy. Using B&M's base case figures, the only certain way to bring the ethane "cost" at Cook Inlet (7.5 cents per pound) down to the ethane "value" (4.3 cents per pound), would be for the state to pay the liquids purchaser(s) \$.90 per MMBTU for the 68.5 billion BTU per day of ethane delivered. If the required subsidy were spread over all of the state's royalty gas and gas liquids from Prudhoe Bay, Alaska would end up with only \$1.12 per MMBTU (\$318,500) for its share of production, rather than the \$1.75 per MMBTU (\$500,500) the state would have received each day in revenue from gas shipments through the Alaska Highway pipeline.[12]

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11) Joe Moore replies that the author of this review " . . . devotes several pages to impacts on the gas pipeline project. We did not treat that subject and I will not comment on it here." [letter to Tussing, January 4, 1980]

Granted, Joe Moore [in his January 4 letter] characterizes the report's contrast between an ethane cost of 7.5 cents and a value of 4.3 cents per pound as a "worst case" example on the ground that those numbers do not reflect any of the offsetting factors he mentions elsewhere. But as we have pointed out, some of these factors do not look particularly promising; these "worst-case" cost calculations, and in addition, wholly fail to take into account the collateral costs (new conditioning design, higher gas pipeline tariffs) that are inescapable if most of the liquids are removed from the sales gas stream.

The preceding calculations, moreover, accept at face value one crucial assumption by B&M which is clearly <u>not</u> the worst case but the best --- namely that the price of hydrocarbons at the tailgate of the conditioning plant, and hence their value in the sales gas stream, will be \$1.75 per MMBTU (in 1979 dollars). This figure is in reality an absolutely irreducible and highly improbable <u>minimum</u>.

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12) <u>Manner of calculation</u>. We imputed the maximum price that the petrochemicals manufacturer can afford to pay for ethane delivered to its plant gate from the ratio between B&M's value and cost figures:

$$\frac{(\$.043)}{(\$.075)} \times (\$1.75 + \$.50 + \$1.03 + \$2.94) = \$3.57 \text{ per MMBTU.}$$

But the irreducible cost of separating the ethane and of transporting the natural gas liquids is:

$$\$.50 + \$1.03 + \$2.94 = \$4.47 \text{ per MMBTU.}$$

Hence, even if the petrochemicals manufacturer received the gas at Prudhoe Bay totally free of charge, somebody would have to make up the 90 cent deficit on each MMBTU of the 68.5 billion BTU shipped daily --- a total of \$61,600 per day. As the producers are unlikely to sell or exchange their Prudhoe Bay hydrocarbons for any price less than they would have received by shipping them through the gas pipeline (much less pay someone to take them away), the state would have to absorb the entire deficit of <u>\$2.65 per MMBTU, or \$181,400 per day</u>. <u>In relation to the entire state royalty share of 285,600 billion BTU per day, the implied subsidy would be \$0.64 per MMBTU.</u>

While the $1.75 conforms to a preliminary FERC ruling that allocates all conditioning costs to the gas producers, the outstanding gas sales contracts add these costs to the $1.75 wellhead price, and the Department of Energy has asked FERC to withdraw its decision and leave the matter up to negotiations among the parties.[13]

It is not unlikely that the final settlement of this issue will provide for addition of 30 to 50 cents per MMBTU to the sales gas price as a partial allowance for conditioning costs. Using the same methods as above, a 30 cent allowance would increase the cost of the whole 395,800 MMBTU per day --- and also its value as part of the sales gas --- by $118,700, to a total of $811,400 per day. The project's revenue deficit would increase by the same amount, and its economics would be further worsened, to the extent of 42 cents for each of the state's 265,600 MMBTU per day of royalty gas and gas liquids. If FERC should agrees to a conditining cost allowance exceeding 30 cents the project's losses would, of course, be increased proportionally.

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13) B&M might conceivably be excused for passing over this issue, but it is surprising that the Birch, et al, appendix to the B&M report, which devotes 23 pages to "Government Controls on Natural Gas and Gas Liquids" and "Feedstock Price Controls and Related Issues," makes no mention whatsoever of the current proceedings regarding the allocation of conditioning costs, which can have such a powerful influence on feedstock prices, and thus on the economics of the proposed petrochemicals plant.

TABLE 1. THE AVAILABILITY OF LIQUIDS FOR SHIPMENT THROUGH TAPS, THE GAS PIPELINE, OR A GAS LIQUIDS LINE[1]

HYDRO-CARBON	INLET GAS[2] to conditioning plant	FIELD FUEL[3]	PLANT FUEL[4]	AVAILABLE HYDROCARBONS[5]	B&M LIQUIDS ACQUISITION[6]
C_2	111.4 Mb/d	39.2 Mb/d	14.5 Mb/d	58.1 Mb/d[7]	24.7 Mb/d
C_3	61.8 Mb/d	22.5 Mb/d	16.7 Mb/d	23.3 Mb/d[8]	57.6 Mb/d[8]
C_4(i)	10.3 Mb/d	.8 Mb/d	.3 Mb/d	9.4 Mb/d	none
C_4(n)	23.7 Mb/d	.9 Mb/d	.1 Mb/d	23.3 Mb/d	20.3 Mb/d
C_5(i)	6.2 Mb/d	.1 Mb/d	none	6.3 Mb/d	4.2 Mb/d
C_5(n)	11.4 Mb/d	.1 Mb/d	none	11.7 Mb/d	none
C_{6+}	9.7 Mb/d	none	none	10.2 Mb/d	none
TOTAL	234.5 Mb/d	63.6 Mb/d	31.6 Mb/d	142.3 Mb/d	106.8 Mb/d

1. Unless otherwise noted, these figures reflect the data provided by the Ralph M. Parsons study report, Sales Gas Conditioning Facilities: Prudhoe Bay Alaska, (which assumes 2.0 bcf/day of sales gas with a minimum of 1 percent CO_2). The translation of the Parsons' data into barrels is based on a table prepared by Exxon USA entitled "Material Balance: Prudhoe Bay Conditioning Plant" [undated]. The vertical and horizontal totals are not precisely consistent, and Table 1 reflects those disparities.

2. INLET GAS consists of the total gas production, less volumes removed by the existing Field Fuel Gas Unit (FFGU) for use in the first four TAPS pump stations and for oil-related field activities.

3. FIELD FUEL is a projection of the maximum fuel volume required for waterflood, artificial lift, etc., less the volume of fuel supplied by the existing FFGU, as calculated by Parsons.

4. PLANT FUEL consists of fuel needed for local heaters and local turbines within the conditioning facility.

5. AVAILABLE HYDROCARBONS are the remainder avaliable for shipment through TAPS, a natural gas pipeline, and/or a natural gas liquids line, after field and plant fuel requirements are provided for.

6. B&M LIQUIDS ACQUISITION reflects the data shown on page C-3 of the B&M report. While B&M state that, "All of the propane and heavier liquids are recovered for a total NGL volume of 107,000 B/D," the B&M figures are not consistent with the volumes of avails calculated by Parsons.

7. 53.3 Mb/d of the initial 111.4 Mb/d remains in the CO_2 waste gas stream.

8. Of all hydrocarbons, only propane (C_3) is available in volumes less than B&M propose for acquisition. The deficit is substantial: 23 thousand barrels per day available, in contrast to 58,000 barrels required.

TABLE 2. THE EFFECT OF THE BONNER AND MOORE STRATEGY ON THE VOLUME AND RICHNESS OF GAS AVAILABLE FOR TRANSPORT THROUGH THE GAS PIPELINE

COMPONENT	TOTAL AVAILABLE HYDROCARBONS[1]	(without petrochemicals project) HYDROCARBONS AVAILABLE TO GAS PIPELINE	(with petrochemicals project) HYDROCARBONS AVAILABLE TO GAS LIQUIDS PIPELINE	(with petrochemicals project) HYDROCARBONS AVAILABLE TO NATURAL GAS PIPELINE (liquid volume)	(gas volume)	(gross energy)[5]
C_1	1,879 MMCF/d[2]	1,879 MMCF/d	none		1,749 MMCF/d[4] =	1,766 BBTU/d
C_2	58.1 MB/d	58.1 MB/d	24.7 MB/d	33.4 MB/d =	53 MMCF/d =	93 BBTU/d
C_3	23.3 MB/d	23.3 MB/d	57.6 MB/d	none	none	none
C_4(i)	9.4 MB/d	9.4 MB/d	none	9.4 MB/d =	12 MMCF/d =	9 BBTU/d
C_4(n)	23.3 MB/d	21.9 MB/d[3]	20.3 MB/d	1.6 MB/d =	2 MMCF/d =	7 BBTU/d
C_5(i)	6.3 MB/d	.8 MB/d[3]	4.2 MB/d	none	none	none
C_5(n)	11.7 MB/d	.2 MB/d[3]	none	none	none	none
C_{6+}	10.2 MB/d	none[3]	none	none	none	none
$CO_2 + N_2$		2.3MMCF/d			2 MMCF/d	
TOTAL VOLUME		2,071 MMCF/d			1,815 MMCF/d	
TOTAL ENERGY[5]		2,291 BBTU/d				1,905 BBTU/d
GAS QUALITY[5]		~~1,086~~ 1,106 BTU/CF			1,050 BTU/CF	

1. AVAILABLE HYDROCARBONS are from Table 1, column 5.

2. 90.71 percent of 2071.

3. Available volumes, less shipments via TAPS.

4. Because 34.3 MB/d of the propane required for field fuel is not available under the B&M scenario, a BTU-equivalent (131 billion BTU per day), presumably methane, must be removed from the hydrocarbons available through the gas pipeline (130 MMCF per day).

5. Heating values are in gross or high heating value (HHV) BTU. All heating value and volumetric conversions are taken from the Gas Processors' Association tables, which we presume are equivalent to those used in the Parsons study.

TABLE 3. THE PROSPECTS FOR A SWAP OF STATE ROYALTY METHANE FOR PRODUCER-OWNED NATURAL GAS LIQUIDS

	HYDROCARBONS AVAILABLE TO THE GAS PIPELINE[1]	1/8 STATE ROYALTY SHARE (volume)	1/8 STATE ROYALTY SHARE (energy)	HYDROCARBONS AVAILABLE TO THE GAS LIQUIDS PIPELINE[2] (volume)	HYDROCARBONS AVAILABLE TO THE GAS LIQUIDS PIPELINE[2] (energy)
C_1	1749 MMCF/d[3]	218.6 MMcf/d	220.7 BBTU/d	none	none
C_2	58 MB/d	7.3 MB/d	20.2 BBTU/d	24.7 MB/d	68.5 BBTU/d
C_3	58 MB/d	7.2 MB/d	27.5 BBTU/d	57.6 MB/d	220.3 BBTU/d
C_4(i)	9 MB/d	1.2 MB/d	5.0 BBTU/d	none	none
C_4(n)	22 MB/d	2.7 MB/d	11.7 BBTU/d	20.3 MB/d	87.8 BBTU/d
C_5(i)	1 MB/d	.1 MB/d	.5 BBTU/d	4.2 MB/d	19.2 BBTU/d
C_5(n)	t	none	none	none	none
TOTAL NGLs		18.5 MB/d	64.9 BBTU/d	106.8 MB/d	395.8 BBTU/d
TOTAL HYDROCARBONS			285.6 BBTU/d		395.8 BBTU/d

1. Figures are taken from Table 2, Column 3. (Inlet gas to conditioning plant, less plant and field fuel, less TAPS allocation, in the Parsons plan).

2. Figures are from B&M report, page C-3.

3. Assumes that the 34.3 MB/d of propane no longer available for field and conditioning fuel is replaced by methane. (See note No.4, Table 2.)

Calculation. State royalty liquids fall 330.9 billion BTU/d short of the volume B&M state is necessary to make a gas liquids line profitable. This shortfall is equivalent to 327.7 MMCF of methane; but the state only has 218.6 MMCF per day of royalty methane available to swap for gas-producer-owned liquids. The shortfall in royalty methane, therefore, is 109.1 MMcf/d, or about 50 percent more than the state owns.

PLEASE NOTE

THE ORGINAL FILE CONTAINS AN OVERSIZED DOCUMENT THAT IS UNSUITABLE FOR FILMING. PLEASE REFER TO THE ALASKA STATE ARCHIVES TO VIEW THE ORIGINAL.

Introduction

In 1968, a wildcat rig drilling on Alaska's North Slope struck the vast petroleum reserve now known as Prudhoe Bay. Estimated to contain 9.6 billion barrels of crude oil and over 26 trillion cubic feet of saleable natural gas, Prudhoe Bay constitutes the largest of the United States' reserves. The Trans Alaska Pipeline System is currently transporting over one million barrels of Prudhoe Bay crude oil daily to southern Alaska for shipment to ports in the United States. Part of the natural gas in this reserve is in solution with the oil and part of it is in a free gas cap above the oil reservoir. Thus, as the oil is extracted, some natural gas is also removed. Until this gas can be marketed it will be reinjected into the reserve for future use. The Alaska Natural Gas Transportation System will provide a means to transport this vast quantity of natural gas to consumers in the Lower 48 States. The initial daily output will be equivalent to about 450,000 barrels of oil.

The Project

The Alaska Natural Gas Transportation System will be an overland pipeline of varying diameters designed to carry about 2.4 billion cubic feet of natural gas daily from Prudhoe Bay, Alaska, to homes and industries in the lower 48 states. At a cost of over $20 billion it will be the largest privately-financed construction project ever undertaken anywhere. It will supply about five percent of our Nation's gas needs for the 25-year life of the project, based on current use rates.

The entire project stretches 4,800 miles from Prudhoe Bay, on the northern coast of Alaska, along the route of the Trans Alaska Oil Pipeline to Delta Junction, south of Fairbanks. There the gas line turns southeast and continues south into Canada, generally following the Alaskan-Canadian highway. Just north of Calgary it splits into two legs—the West Leg going to Antioch, California and the East Leg almost to Chicago. Construction is scheduled to start in 1981 on the two lower Legs. The last portion to be built, the Alaskan segment, is now scheduled for completion in 1985.

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413, POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON, D.C. 20044

Official Business

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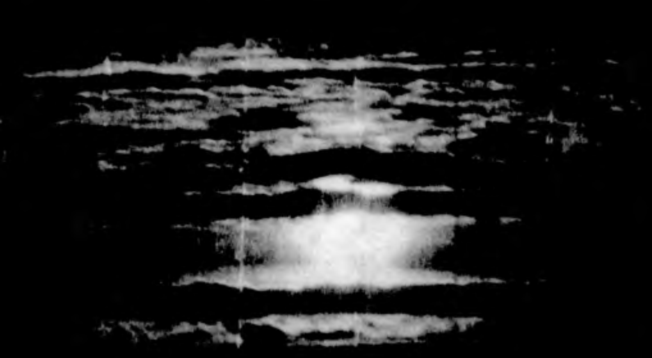
ALASKA NATURAL GAS TRANSPORTATION SYSTEM



Photos: Steucke

Cover: Sunset at the Arctic Circle. Above: Rugged snow covered mountains in August.

Legislative History

The U.S. Congress enacted the Alaska Natural Gas Transportation Act on October 22, 1976, setting out a series of innovative procedures to expedite the selection, approval and construction of a natural gas pipeline system to bring Alaskan gas to lower 48 markets. After receiving a recommendation from the U.S. Federal Power Commission (now the Federal Energy Regulatory Commission), the President in September 1977 selected a route and applicant. Congress in November of that year approved the President's selection.

Office of the Federal Inspector

The Office of the Federal Inspector is a small but unique, independent entity created by Congress and the President specifically to expedite and oversee construction of the Alaska Natural Gas Transportation System. Congress in its 1976 legislation clearing the way for the project included the requirement that a single individual, to be called the Federal Inspector, be appointed to be responsible for assuring that the project is built as timely as possible, without excessive cost overruns, and with minimal harm to the environment. It included that requirement because the undertaking is itself unique in size and in importance to the Nation's energy future, and in light of the delays and large cost overruns that have in the past plagued large construction projects, such as the Trans-Alaskan Oil Pipeline.

The exact duties of the Federal Inspector were not defined until Reorganization Plan No. 1 was signed by the President on June 11, 1979. The concepts of that Plan were set out in Executive Order No. 12142, signed by the President on June 21. These three Presidential documents combined to implement the intent of Congress embodied in the ANGTA of establishing the Office of the Federal Inspector, which officially came into being July 1, 1979.

O.F.I. Responsibilities

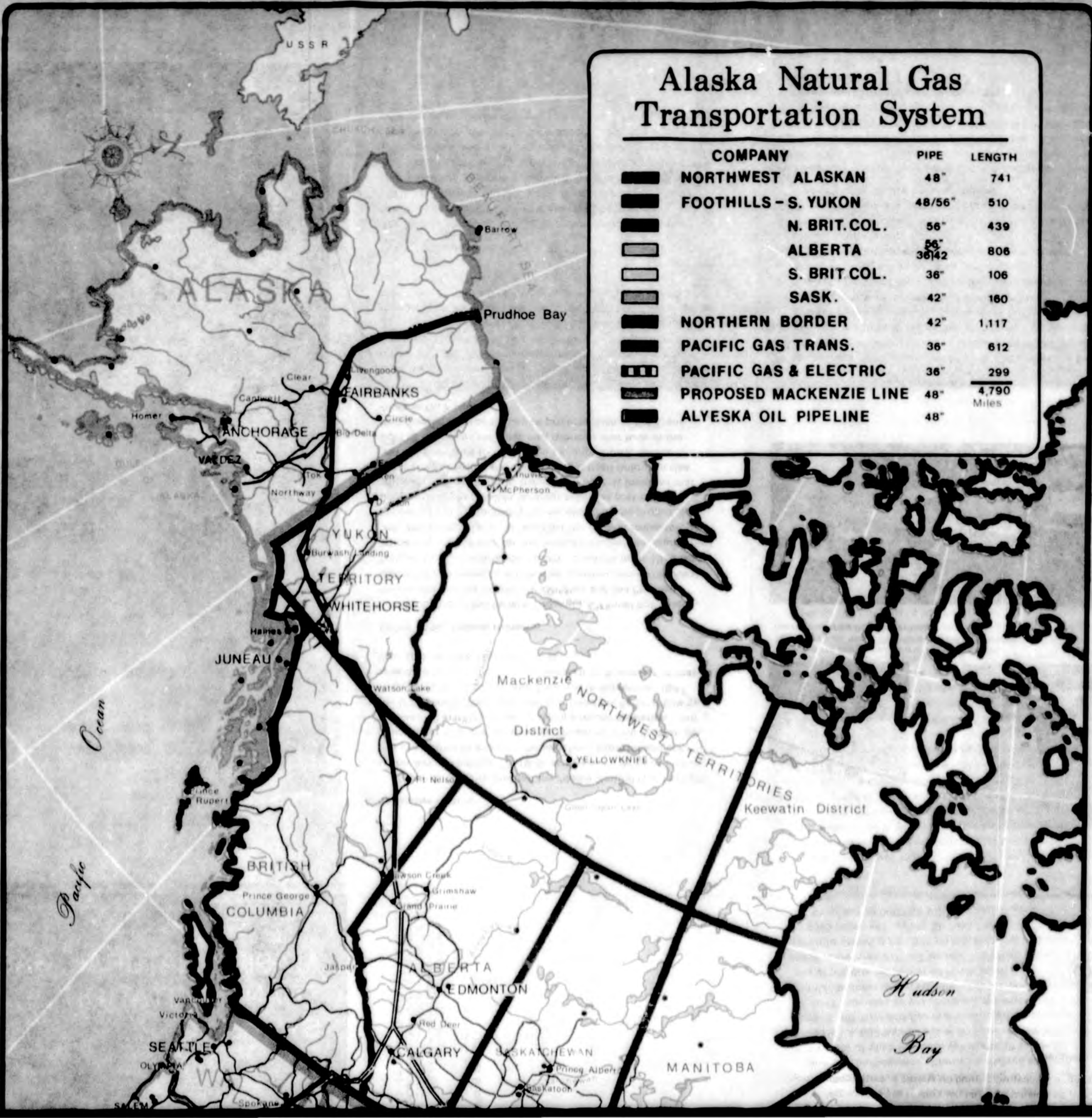
The Federal Inspector is an independent entity within the executive branch, established to oversee all construction and initial operation of the U.S. portions of the pipeline. He will coordinate and schedule actions of the eight Federal agencies which must approve some aspect of the project; monitor construction; and enforce all certificates and conditions issued by the agencies. He will be the "one window" for receipt of all data and permit applications and for issuance of all permits.

The Alyeska oil pipeline transports oil from Prudhoe Bay, Alaska, to Valdez. Below: The Alaska-Canadian highway under construction by the U.S. Army in 1942.

Specifically, the Federal Inspector will:

1. coordinate the scheduling and issuance of all Federal permits and related activities to assure timely and unified decisions;
2. monitor activities to assure that cost control, safety, and environmental protection objectives are fulfilled while still meeting the project completion schedule;
3. keep the President and Congress informed on project progress, including potential delays or problems;
4. establish a joint surveillance and monitoring agreement with the State of Alaska; and
5. enforce all Federal statutes which affect the project, assuring that the builders are complying with all conditions or stipulations attached to any Federal approval.

Although the Federal Departments of Transportation, Energy, Interior, Agriculture, Treasury, the Environmental Protection Agency, U.S. Army Corps of Engineers, and the Chairman of the Federal Energy Regulatory Commission retain their authority to issue necessary permits and certificates, the Federal Inspector must assure that the agencies make these authorizations in timely fashion.


Alaska Natural Gas Transportation System
COMPANY PIPE LENGTH
NORTHWEST ALASKAN 48" 741
FOOTHILLS - S. YUKON 48/56" 510
N. BRIT. COL. 56" 439
ALBERTA 56" 36/42 806
S. BRIT COL. 36" 106
SASK. 42" 160
NORTHERN BORDER 42" 1,117
PACIFIC GAS TRANS. 36" 612
PACIFIC GAS & ELECTRIC 36" 299
PROPOSED MACKENZIE LINE 48" 4,790 Miles
ALYESKA OIL PIPELINE 48"
USSR
ALASKA
BEAUFORT SEA
Barrow
Prudhoe Bay
Livengood
Clear
FAIRBANKS
Cantwell
Homer
ANCHORAGE
Big Delta
Circle
VALDEZ
Tok
Northway
Inuvik
McPherson
YUKON
TERRITORY
Burwash Landing
WHITEHORSE
Haines
JUNEAU
Watson Lake
Mackenzie
District
NORTHWEST TERRITORIES
YELLOWKNIFE
Keewatin District
Ft. Nelson
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BRITISH
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Prince George
Dawson Creek
Grimshaw
Grand Prairie
Jasper
ALBERTA
EDMONTON
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CALGARY
SASKATCHEWAN
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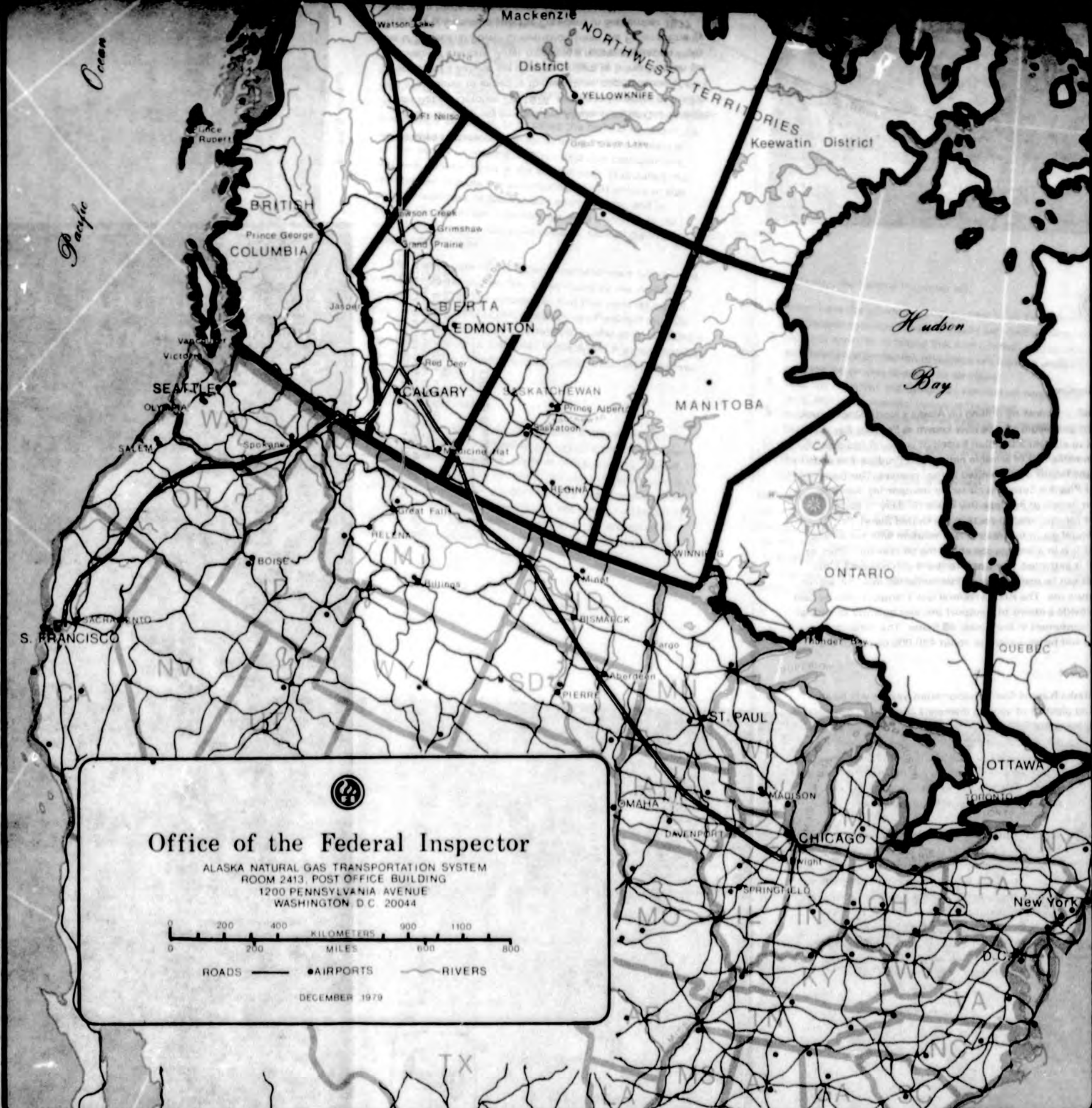
MANITOBA
Vancouver
Victoria
SEATTLE
OLYMPIA
Spokane
Pacific
Ocean
Hudson
Bay



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