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:

Connie C. Barlow
Arlon R. Tussing and Associates, Inc.
811 Basin Road
Juneau, Alaska 99801
(907) 586-3930, <u>or</u>

Arlon R. Tussing and Associates, Inc.
2720 Rainier Bank Tower
Seattle, Washington 98101
(206) 447-0321

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.

----

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.

----

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 order 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]

----

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] 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.

----

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 ratably, 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, Government Controls Affecting Development of an Alaskan Petrochemical Complex using North Slope Natural Gas Liquids Feedstock [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 events 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)	(¢/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]

----

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]

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 calculatè 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]

----

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 existing 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 new facility if penetration of the market appeared to require "cash-cost" pricing from the outset.

Finally, 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]

----

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>.

----

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:

$$\frac{(\$.043)}{(\$.075)} \text{ X } (\$1.75 + \$.50 + \$1.03 + \$2.94) = \$3.57 \text{ per MMBTU.}$$

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.

----

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 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	464.9 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.