

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1034 SCOMM 28: JOINT GAS PIPELINE COMMITTEE, 1981-82

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

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

\$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 amended. 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 transported via the ANGTS. This conveys an impression that the NGPA's framers held special concerns regarding Alaskan gas and its pricing vis-a-vis the viability of the ANGTS.

In summary, there are two important factors at work here which will make Prudhoe Bay gas transported via the ANGTS more marketable than it would otherwise be: (1) the controlled, 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 ANGTS 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 industry, 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

^{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 transport 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 mortgage 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 nominal 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) might 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 annual 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 dated 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 called "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 fuels 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 assumption 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 practice 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 transportation -- 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 competitive situation that there would be little alternative but for its 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 or 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

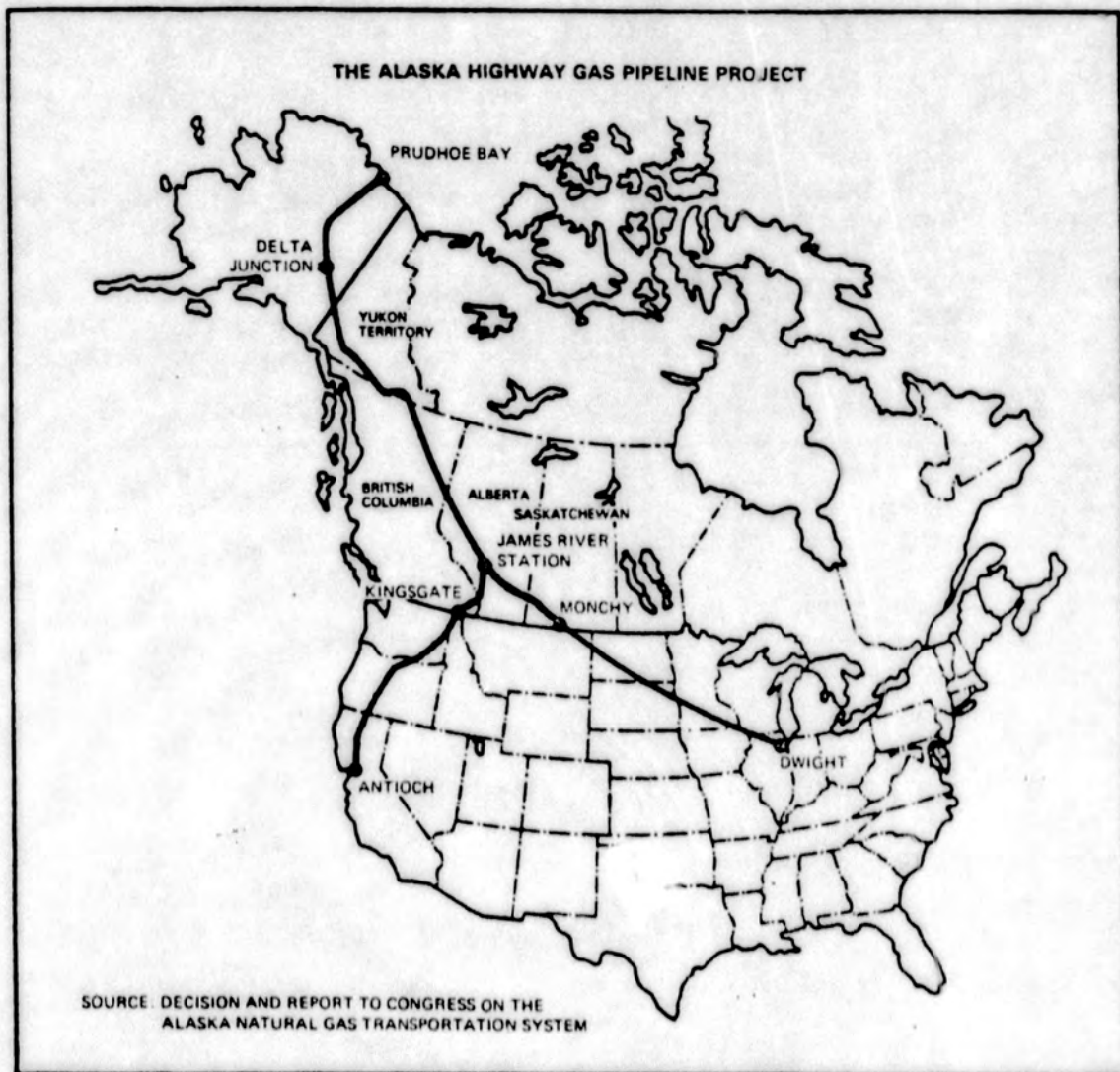
U.S. relations with Canada are extremely complex and interwoven. Each country is the other's largest trading partner and each attracts the largest share of the other's foreign investment. However, two basic differences between the two countries dominate their relationship. First, the U.S. is ten times 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

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

Map I



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 countries. 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 probably 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 foreseeable 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

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 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.

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)

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

*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 quantification 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 perception 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 interest rates mean higher project costs and as a result lower NNEB as shown in Chart I.

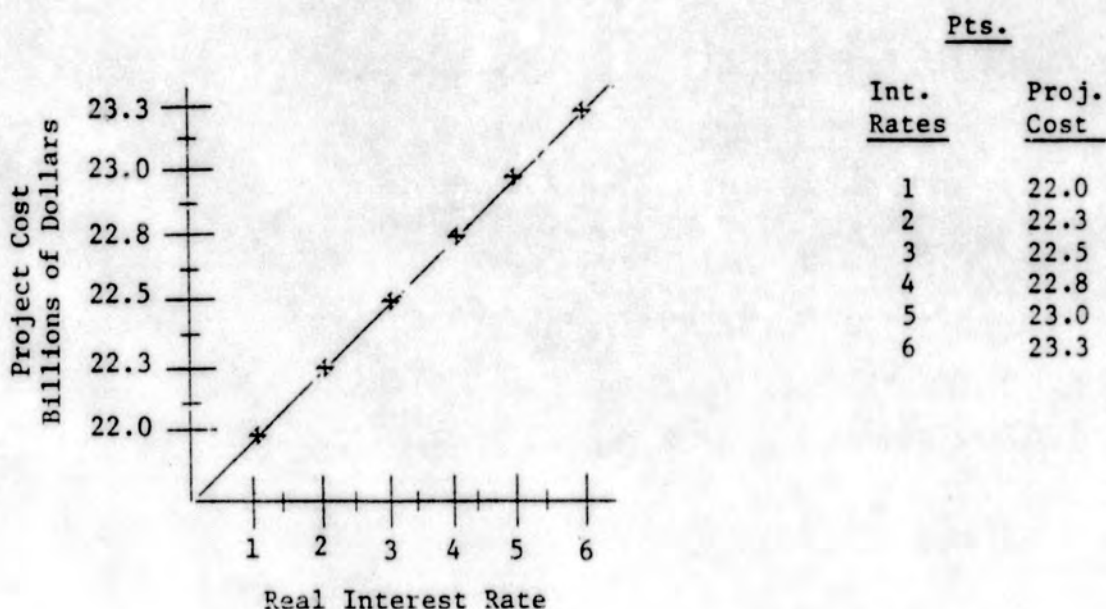
The Congressional Research Service (CRS) used the Office of the Federal Inspector's (OFI) Cost-of-Service Model to test project cost sensitivity to interest rates. The OFI's base case uses an interest rate of 11 percent and an inflation rate of 8 percent in projecting the ANGTS cost of \$44 billion or \$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

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

CHART I

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



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

^{7/} Mead, Walter J., Transporting Natural Gas From the Arctic
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/

	<u>95% probability</u>	<u>5% probability</u>	<u>statistical mean</u>
Onshore Regions	19.8	62.3	36.6
Offshore Regions	33.3	109.6	<u>64.6</u>
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/

	<u>Probable</u>	<u>Possible (Fairly Likely)</u>	<u>Speculative</u>
Onshore	6	16	28
Offshore	<u>2</u>	<u>13</u>	<u>80</u>
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

^{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.

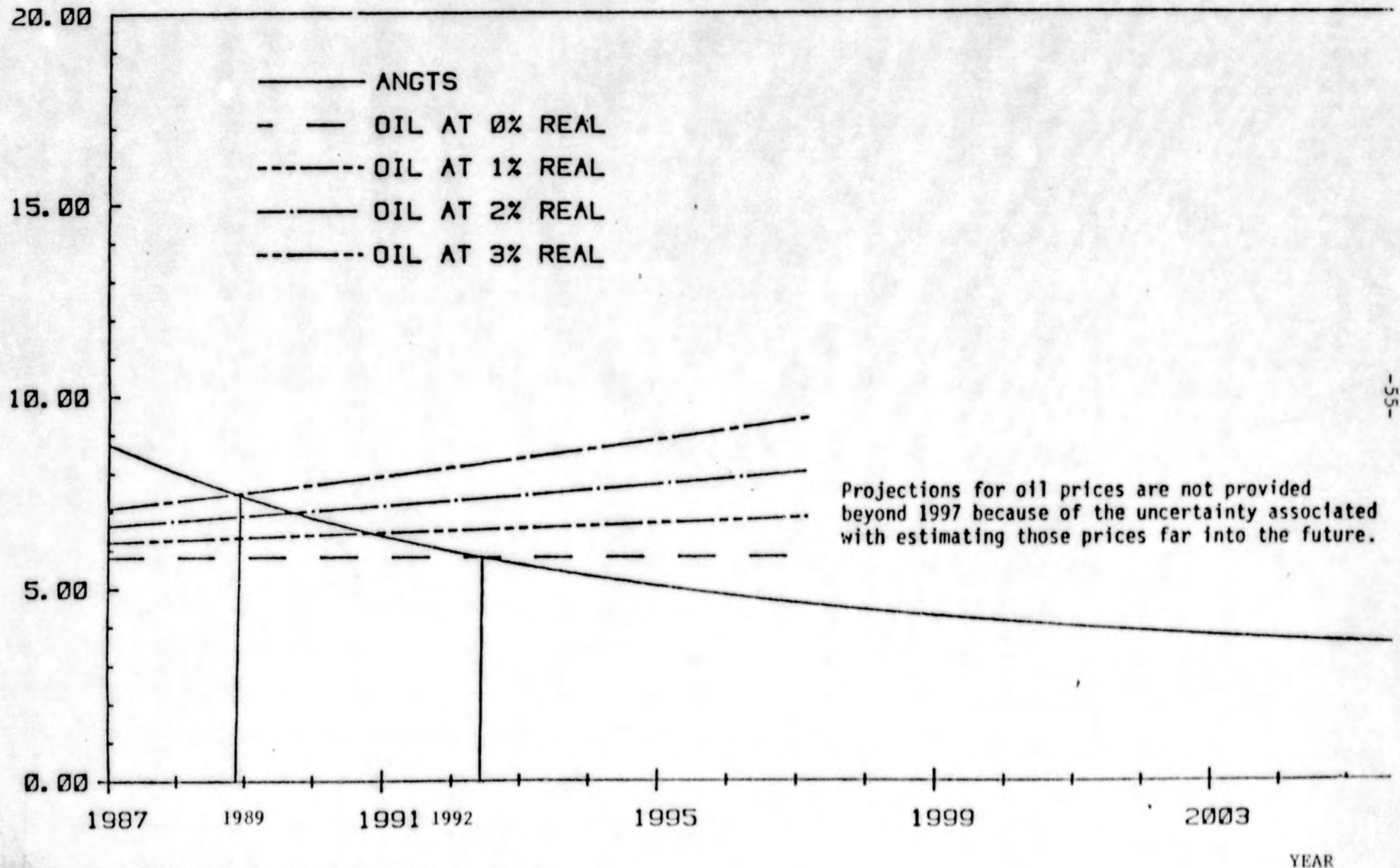
E. World Oil Price Behavior

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

ANGTS VS OIL

LOW ASSUMPTIONS - CONSTANT 1980 DOLLARS/MMBTU



Source: Office of the Federal Inspector.

YEAR

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.

*/ 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

^{*}/ 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.

*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.

* 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

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, Swedwards 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

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 (CO₂) 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 CO₂, 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 CO₂ 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 CO₂ 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

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 efficiency relative to energy content associated with the end use of methanol as a fuel (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

^{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

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

^{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

^{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 CO₂ 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 methanol could develop in the electric power industry if the cost does not exceed that of current fuels. Once storage facilities and fuel lines are sized for 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. NO_x 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

^{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

$$k = (1-T)k_D \cdot f_D + k_E \cdot f_E$$

Where T 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 (billions of \$)	Case II
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

<u>Year</u>	<u>% Total</u>	<u>1981 \$</u>	<u>1981 \$</u>
1982	10%	\$.693	-----
1983	50%	\$3.466	.850
1984	30%	\$2.080	4.250
1985	10%	\$.693	2.550
1986	---	-----	.850

Operating Costs (1981 \$)

1. Operating Labor	\$150.0 million/year
2. Overhead (.15% of O.L.)	\$22.5 million/year
3. Maintenance (7% of TCR)	<u>\$485.3 million/year</u>
Subtotal	<u>\$657.8 million/year</u>
4. Feedstock Costs (c=cost of gas \$/1,000 scf)	

$$(\$c/1,000 \text{ scf})(20)(100 \times 10) = \$2,000 \text{ c} \times 10 / \text{day}$$

$$\text{service factor} = 330 \text{ day/year}$$

$$\$660 \text{ c} \times 10 / \text{year (1981 \$)}$$

<u>c</u>	<u>Feedstock Costs (1981 \$)</u>
\$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 Arctic North Slope. 2/

*/ 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/

	<u>95% probability</u>	<u>5% probability</u>	<u>statistical mean</u>
Onshore Regions	19.8	62.3	36.6
Offshore Regions	33.3	109.6	<u>64.6</u>
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/

	<u>Probable</u>	<u>Possible (Most Likely)</u>	<u>Speculative</u>
Onshore	6	16	28
Offshore	<u>2</u>	<u>13</u>	<u>80</u>
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

3/ Dolton, G. L., et al. Estimates of Undiscovered Recoverable Resources of Conventionally Producing 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 possible offshore potential by the Potential Gas Committee would indicate the future discovery

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

^{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 is 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

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

(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 fields 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

^{17/} Wilson, Howard M., op. cit.

^{18/} Ibid.

^{19/} Dolton, G. L., et al., op. cit., p. 8, 9, 11.