

# The Struggle for an Alaska Gas Pipeline: What Went Wrong?

# DOES NOT CIRCULATE

## INTRODUCTION

The Prudhoe Bay field on Alaska's North Slope holds the biggest known crude oil deposit and one of the largest accumulations of natural gas in the United States—gas reserves so great that they alone could saty the demand of the entire United States for well over a year.

The field was discovered in 1968 and, since reaching full production in 1978, has been producing about 500 million barrels of crude oil per year for lower forty-eight markets. But in the absence of a gas transportation system, almost all of the natural gas produced in conjunction with the oil has been so far reinjected into the reservoir.

How has this come about? Back in the late seventies and early eighties, when most private and government experts believed that the energy shortage could only get worse and prices could only go higher, the building of a pipeline to transport Alaska North Slope gas to market in the lower U.S. seemed not only a profitable certainty, but almost a patriotic duty. Congress passed legislation in 1967, 1977, and 1982 to smooth the way for an Alaska natural gas transportation system (ANGTS), and the United States entered into a compact with Canada expressly on behalf of ANGTS.

Yet, 15 years after the Prudhoe Bay field was discovered and 6 years after the U.S. and Canadian governments approved the gas transportation system configuration and the sponsoring parties, the sponsors of ANGTS have yet to produce a credible financing strategy or plan. As a result, in middle 1983, the project is still stalled and its future is in serious doubt.

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#### SUMMARY

From a mid-1983 standpoint, the Alaska Natural Gas Transportation System (ANGTS) as it is now conceived, designed, and organized does not appear to be an economically sound venture.

At the construction costs implied by the system design, the rates of interest prevailing in the market, and the rates of return to equity contemplated by the sponsors and the regulatory bodies having jurisdiction over the system, it seems unlikely that anything closely resembling ANGTS will be able to deliver natural gas to the Lower-48 states at a price consumers would be willing to pay.

The present project is so far from being economically feasible, moreover, that we cannot see any combination of internal project changes (in design, organization, or in gas-marketing or financing strategy) or regulatory and legal changes short of direct federal financial participation, which would assure construction and operation of the system.

Our conclusion stems from a number of developments in the structure of natural-gas demand in the United States, the world oil price and supply outlook, general price-level trends, and capital-market conditions. This report contains the crucial price and cost comparisons on which we have made this judgment. Not every analyst will agree with our views on all of these issues, and unforeseen developments might substantially change the outlook on any of them. The fact that we might be wrong on one or a number of these questions may be beside the point, however:

Sufficient uncertainty and controversy now exist on the crucial issues that investors cannot help but regard ANGTS as an unacceptably speculative venture.

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### FEATURE

Arlon R. Tussing Connie C. Barlow The Struggle for an Alaska Gas Pipeline: What Went Wrong?

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Why did this project, that seemed to hold so much promise, never get off the ground? The main purpose of this report is to answer that question—to assess what went wrong and determine what, if anything, can be done to make ANGTS a reality.

# CHANGED PERCEPTIONS OF NEED Alaska

Mainstream business leaders in Alaska and many of the state's political leaders would like to believe that the time for the Alaska Highway Gas Pipeline has come and gone, as long as that belief does not imply that the time for North Slope gas sales in general has also come and gone. Following Northwest Alaska Pipeline Company's April 1982 announcement of a 2-year delay of ANGTS construction, the state appointed new committees and task forces to look at alternatives. One of those committees (appointed by Governor Hammond and co-chaired by two previous governors, Egan and Hickel) has resurrected El Paso's scheme for an "All-Alaska" gas pipeline to an LNG plant on tidewater, which would generate more construction business in the state than ANGTS, and deliver North Slope gas into the state's main population and industrial area.

Unlike the El Paso Alaska effort, the committee of ex-governors has not limited its sales pitch to gas companies in the southern forty-nine states, but is also actively soliciting interest from the Far East. After all, Alaska already has one operational LNGexport facility. Two producers of Cook Inlet gas joined in the late 1960s to build a liquefaction plant and tankers to carry gas to customers in Japan; renewal of the 15-year contract is now before the Economic Regulatory Administration (ERA).

Alaska business and political leaders, therefore, are enthusiastic about marketing gas from Prudhoe Bay, but many of them have been lukewarm at best to the Alaska Highway project. Past actions, most notably an Alaska push for a petrochemical industry based on North Slope gas, demonstrate that the state may not only be unwilling to put any debt or equity money into ANGTS, but that it is not above doing something which, on balance, may threaten the economics of downstream shipments.

Nevertheless, the State of Alaska has a oneeighth royalty interest in both the gas and oil at Prudhoe Bay, and has the authority to levy taxes on gas production and the pipeline. From that standpoint, its economic interests in the project are similar  $\dagger$ those that motivate the primary leaseholders—Arc Exxon, and Sohio. However, the chance that Alaska would play a major independent role in resolving the present impasse over ANGTS is, and will probably

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remain, trapped in a vicious circle. The clear prospect of success would rapidly shatter the present diffidence of Alaskans toward ANGTS and make it a popular cause in the state. But until and unless ANGTS appears to be going ahead *without* major organizational initiatives or risk-bearing by the state, it will not have sufficient momentum or credibility to overcome these deep-seated qualms and ambivalences. In other words:

Substantial assistance to ANGTS from the state of Alaska is thus likely to be forthcoming if and only if that assistance does NOT appear crucial to project success.

#### Canada

Canadian perceptions of the importance of ANGTS contrast sharply with those of a half dozen years ago when the Foothills group of Canadian pipeline companies joined the Alcan team. They contrast even more sharply with the ideas that inspired the competing Arctic Gas and Maple Leaf pipeline proposals in the mid-1970s (both of which would have employed a Mackenzie River corridor for gas from the Arctic).

Canadian officials and sponsors of the two Mackenzie Valley proposals saw them in much the same way that U.S. officials and pipeline sponsors viewed the Arctic Gas and El Paso proposals. A gas pipeline from the Arctic would be, first and foremost, a vital energy-supply facility. Canadian authorities had virtually written off the traditional producing areas as a source of additional oil or gas and believed that one or more gas pipelines from the Arctic had to be completed by the mid-1980s in order to head off a critical domestic shortage. In addition, jobs, local procurement, and the balance-of-payments impact of pipeline construction always loomed as a larger consideration in Canada's smaller economy than they did in the United States.

By 1976, however, when the Alcan group filed its applications to build an Alaska Highway pipeline, it was already becoming apparent that new discoveries in Alberta and the other western provinces would be sufficient to meet domestic demand in Canada for many years. This development in itself may have been sufficient to insure that Alcan would defeat the larger, better-funded, and better-connected Arctic Gas proposal, which would have carried gas from both the Alaskan and Canadian Arctic.

In line with the diminished urgency of connecting Canadian Arctic reserves to southern markets, the Alcan plan as adopted in 1977 provided for building a pipeline spur from the MacKenzie Delta along the Dempster Highway at some unspecified future time. Even in 1977, however, the notion that ANGTS would be "needed" to serve Canadian energy marke at any time in the foreseeable future was well on the way to becoming a diplomatic fiction, whose main purpose was to counter nationalistic opposition to an American big-business "land bridge" across Canada.

Canadian authorities later rationalized the "prebuilding" of the southern portions of ANGTS not as a gas-export facility *per se*, but as an essential demonstration of the Alaska project's overall credibility and as a source of cash flow to assist in financing the longer segment from Alaska. The government was still giving lip-service to its earlier concern about domestic gas-supply shortfalls, packaging additional exports throughout the prebuilt segments as "loans" of Canadian gas to be repaid later with gas from Alaska, and justified them not as legitimate transactions in their own right but mainly as a means of financing the prebuilt facilities.

By late 1982, however, the Dempster Lateral and repayment from Alaska of gas "borrowed" from Canada were moot and nearly forgotten issues. Canadian support for ANGTS persists mainly because the pipeline would be a source of jobs and foreign exchange (considerations not easily dismissed in the current depression), and because of the moral and political capital the Trudeau government has invested in i The gas-market implications of ANGTS in Canad have, however, turned nearly upside-down. Canada not only has more than enough gas to serve its domestic needs for decades, but now has to hustle to preserve its existing share of U.S. markets. In this situation, the principal impact of gas shipments from Alaska would be to displace Canadian gas that would otherwise be exported through the "prebuilt" sections of ANGTS and other facilities to U.S. markets.

The upshot is that the Canadian government will continue to give the project only nominal support and only for so long as it still has nominal support from its private sponsors and from the U.S. government. Also, since the gas supply and the markets supporting ANGTS are both in the United States, there is little anyone in Canada can do to help resolve the present impasse. And even if Canada could contribute a significant new push for ANGTS, it is unlikely that the Canadian government would undertake any exceptional effort or assume any new political risks on its behalf.

#### The North Slope Oil and Gas Producers

The official view of the relationship between ANGTS and the big three North Slope gas produce (Exxon, Arco, and Sohio) has changed radically sind the 1977 presidential decision, which forebade the oil producers from taking part in pipeline financing, ownership, or management. Until about 1981, the roducers were generally regarded (and they regarded themselves) as mere passive recipients of whatever wellhead ceiling price was allowed by U.S. regulation. While it was generally expected that they would condition the gas as well as produce it 1 and that the producers would contribute their credit strength in one form or another to raise debt capital for the pipeline, the presidential decision specifically barred producer participation in pipeline ownership and management.

For more than 3 years after the presidential decision, neither the management of Northwest nor the Carter Administration spelled out exactly what they expected from the producers in the way of financial support. The public position of Northwest was that the pipeline could be financed on a totally nonrecourse basis, without external guarantees because noncompletion risk was a myth according to Northwest's financial advisors, who claimed that gaspurchase contracts were all the security lenders would demand in the pipeline's operational phase. In our 1978-79 inquiry on ANGTS financing for the Alaska Legislature, we discovered that no one having present or potential interest in the project outside of Northwest, its closest financial advisor Loeb Rhoades, and he U.S. Department of Energy, took this theory or orthwest's financing strategy seriously, or even believed that Northwest believed its own professions about financing strategy.

The most common view in Congress was that Northwest's real strategy was to place the federal government in a position where it could not refuse financial aid. The producers, however, believed that Northwest and the federal government were, by implication, innuendo, and threat, offering them and the state of Alaska a "deal." In return for receiving the ceiling price established in NGPA, which was likely to be substantially in excess of the market value of North Slope gas, the producers and the state of Alaska were expected to guarantee the project's debt. In our view, this was probably the most accurate speculation.

The producers, however, made it clear that they had no intention of contributing debt guarantees to a project in which they lacked management participation. Since ANGTS needed all the financial support it could muster, Congress agreed in early 1982 to a "waiver" of the prohibition on producer equity participation. The producers won the support of Northwest for a provision in the legislation that incorpor-

ed the conditioning plant into ANGTS, meaning

that the producers would not have to pay conditioning costs out of the NGPA ceiling price. The producers have in turn made a collective commitment to put up 30 percent of the equity and back 30 percent of the project debt, up to a project total of \$30 billion for the Alaska segment and the conditioning plant.

The trend towards increased producer involvement in the shipment and marketing of Alaska gas has a logical end only at the point where the producers become the chief advocates of a transportation system for Alaska gas and put forth the greatest effort to bring it about. But they understand the economic improbability of the venture right now, and the remaining unrealistic elements in Northwest's financing strategy. While prolonged reinjection of the gas will gradually increase the cost of oil recovery (as more wells must be drilled to accommodate the increasing volume of gas lifted with each barrel of oil), it will neither "hurt" the crude reservoir, nor impose serious economic limits on crude oil production. The producers are thus in no hurry to make big changes or big new outlays of money.

Moreover, in addition to already using 10 percent of the produced gas to fuel practically all of the stationary energy needs on the North Slope, the producers are now experimenting with ways to use gas for "tertiary" methods of enhanced oil recovery. In early November 1982 they announced plans to invest \$100 million in a pilot project for injection of enriched gas (combined with gas liquids to make it "miscible" with crude oil) directly into the reservoir. Miscible flood is believed to offer benefits that simple reinjection of gas into the gas cap cannot provide.<sup>2</sup>

Whether miscible flood or other local uses of gas (such as steam injection for extraction of the many billions of barrels of heavy crude oil known to exist in the vicinity of Prudhoe Bay) become widespread, the producers will surely weigh the options for use or sale of North Slope gas carefully. If, for example, the crude-oil netback price were to remain at the present level of about \$17 per barrel, and if an outside market offered a wellhead price for gas of, say, 40 cents per mmbtu, it might be more profitable to use gas for enhanced oil recovery if available technologies would consume no more than about 6 btu of gas for each btu of additional oil recovered. If the export scheme carried a substantial risk with respect to actual receipt of wellhead revenues, an even less efficient process for enhanced oil recovery might turn

<sup>&</sup>lt;sup>T</sup>However, the decision and the NGPA both left open the question of whether conditioning costs would be absorbed or added on to the wellhead price.

<sup>&</sup>lt;sup>2</sup>Connie C. Barlow and Arlon R. Tussing, "Use in Alaska of North Slope Natural Gas," *Alaska Review of Social and Economic Conditions*, 20:2 (Anchorage: University of Alaska, Institute of Social and Economic Research, 1983), 16 pp.

out to be a better use for the gas.

Should the producers choose to use substantial amounts of North Slope gas for enhanced oil recovery, there will undoubtedly be a considerably larger resource to draw from than the 26 trillion cubic feet of proved reserves at Prudhoe Bay. Already, the producers have announced a likely output of 250 million cubic feet per day (equal to about 9 percent of potential Prudhoe Bay production) from the yet undeveloped Endicott field in the Beaufort Sea.

The Prudhoe Bay gas producers and other leaseholders on the North Slope have a more powerful interest in finding profitable ways to dispose of their gas than anybody else. If the present ANGTS plan founders, and if there is any system for export of the gas that has a profit potential, initiation and success of the alternative will probably fall to the producers which, together with the state, own the gas and are capable of the biggest financial inputs.

Nevertheless, the producers can afford to wait. S.J. Reso, Senior Vice President of Exxon, when questioned during the Congressional "waiver" hearings, stated:

"Eventually there will be a gas outlet from the North Slope of Alaska, because it is not only Prudhoe Bay, but there is other exploration going on up there, and there are other reserves being found, and there will be more reserves found. There will be an outlet for gas... If this pipeline does not get built as currently planned, with the current makeup, everybody involved here, everyone you are looking at will be back thinking of other ways to put together another pipeline."

#### Interstate Gas Pipeline Companies

Although interstate pipeline companies have thus far taken the lead in the scheme to market North Slope gas, their enthusiasm has diminished markedly. Shortly after the announced delay in ANGTS, one of the ten pipeline sponsors pulled out. American Natural Gas had the least stake in project success; its accumulated contribution for project promotion and design was only \$29 million. Like any regulated utility, its ability to avoid a loss by incorporating these promotional expenditures in its tariff will be decided by those who regulate its business. The record of federal regulators in this area does not give rise to much hope that the company would be allowed to recover the costs of a pipeline that was never completed.

As of October 1981, the ANGTS consortium had spent about \$550 million. Those companies with the largest contributions will be especially reluctant to call it quits. Nevertheless, there is a limit to how long and how far a company will go in pursuit of any project, and especially one whose momentum is on the decline. It is safe to say that none of the sponsoring pipelines would want to receive Alaska gas today, when they cannot find buyers for all their existing gas purchase commitments. And as the prospect of future shortages diminishes and especially if deregulation swells gas discoveries in the lower 48 states, the pipeline companies may seriously question whether they will want high-cost Alaska gas within the foreseeable future.

If the ANGTS certificate is abandoned, and as long as gas shortages do not loom on the horizon, there is little chance that the involved pipeline companies (or others, for that matter) will take the lead in putting together another plan for shipment of Alaska gas south. They will, of course, seek new investments in the gas industry as long as conditions prove profitable (and especially as long as they are regulated in a way that confronts them with a "vanishing rate base"), but there are more certain avenues for investment than an Alaska gas pipeline.

# CHANGED EXTERNAL CIRCUMSTANCES

The most damaging problems for ANGTS have been those over which the sponsors had no control. The two most crucial developments, unanticipated by the sponsors and by most governmental bodies concerned with ANGTS, have been (1) a fundamental revolution in the structure and behavior of natural-gas markets in North America, and (2) an interruption (and possibly, the end) of the rise in world oil prices that began in 1973. The project's difficulties have also been exacerbated by a general economic environment that included high and (until recently) accelerating rates of inflation and market interest rates.

#### The Revolution in U.S. Gas Markets

The most dramatic change in the U.S. gas market has been the end of gas shortages and the appearance of widespread gas surpluses. Pipelines that were being sued by gas distributors only 5 years ago for failing to *deliver* contracted volumes of gas are now being sued by upstream sellers for failing to *take* as much gas as they have promised to buy. Throughout the United States, producers, pipelines, and distributors are finding that they have more gas available than they can sell. In our analysis, most U.S. gas markets have not merely "cleared"<sup>3</sup> but have, indeed, swung beyond the point of market-clearing.

The most important source of this change has been the Natural Gas Policy Act of 1978 (NGPA)

<sup>&</sup>lt;sup>3</sup>The market has "cleared" when there exists neither an excess of demand nor of supply at the prevailing prices.

enacted the year after the President and Congress selected the sponsors and the route of the ANGTS project. The NGPA initiated a partial and phased relaxation of wellhead price controls, thereby encouraging producers to find and develop more gas and allowing interstate pipelines to bid away "surplus" gas from intrastate markets. Higher prices for domestic gas under the NGPA have not been the only causes of gas-price increases. Other contributing factors have been imports of foreign pipeline gas and LNG at prices substantially above the pipeline companies' average gas-acquisition costs, plus a steady stream of investments in new transmission, distribution, and storage facilities.

Motivated by memories of gas curtailments in the 1970s, pipelines bought additional gas under NGPA in an "open" market which included domestic gas categories that the law freed from price controls, gas formerly confined by regulation to intrastate buyers, and foreign supplies. Virtually disregarding the fact that most of this gas was priced well above its final-market value, the transmission companies' gasacquisition programs overshot their mark. By late 1982, too much gas had come into the system on long-term contracts with rigid "minimum-take" proisions, and at prices too high to resell.

Although Congress conceived of the NGPA as a gradual approach to the *deregulation of wellhead* prices for new gas in 1985, the law has in reality meant total deregulation of final consumer prices for gas. Higher retail prices have dramatically restrained consumption, completing the course toward "market clearing" years sooner than most industry or government analysts imagined.

High prices began to drive industrial customers from a few pipelines and gas-distributors to alternate fuels as early as 1979. By 1982, most systems in the United States were losing large parts of their industrial loads. Even homeowners and other customers who lack ready access to a lower-price substitute have been consuming less and less gas. Load losses, in turn, are forcing prices to go up even further as each unit of gas sold must bear a bigger portion of pipeline and utility fixed costs, and as contract provisions have given pipelines with excess supplies little choice but to shut in their cheapest rather than their most costly gas.

These developments are not just transitory effects of the economic recession or the retreat in world oil prices. They reflect a revolution in the ucture and behavior of North American gas marits, a change every bit as profound and long-lasting as the revolution in world crude oil markets that took place in the early 1970s. The economic slump and falling oil prices have only accelerated the arrival of the kind of gas market many analysts did not expect to appear until sometime after 1985.

Seven Crucial Implications of the Gas-Market Revolution. Several changes in gas-market circumstances during the early 1980s fatally undermined the assumptions that had, in the last decade, guided industry and government decisions, including the concept and strategy for ANGTS. By November 1982, no gas-transmission or distribution company in the United States could ignore the *symptoms* of change in the industry, but few of them had yet recognized or begun to act upon the recognition that this change was fundamental and permanent. By mid-1983, most, if not all, of the following propositions were becoming part of a new consensus in industry and government.

<u>First</u> and most fundamentally, the gas shortage is over for good.

<u>Second</u>, the marketplace does not regard gas as a "premium fuel." The market value of an incremental gas supply is, at most, its priceequivalent in high-sulfur residual oil.

<u>Third</u>, the nearly unanimous gloom that existed until recently about anticipated shortages in the future supply of conventional domestic gas seems to have been unwarranted.

Fourth, Canada and Mexico now support huge gas surpluses (relative to any prospective U.S. supply deficiency), and their prospects for new finds are even brighter than in the United States.

<u>Fifth</u>, the degree of market-clearing that these forces have already achieved precludes the use of "rolled-in pricing" as a tool for marketing gas priced above its market value.

Sixth, in a market where gas sales are constrained by low demand rather than by supply, gas-supply project financing cannot depend for debt-security on "consumer-guarantees"—contracts signed by "downstream" pipelines or gas distributors.

<u>Seventh</u>, the weakness of "consumer guarantees" effectively means the end of "nonrecourse project financing," like that contemplated by the ANGTS sponsors.

The Long-Term Gas-Market Outlook. ANGTS is, after all, planned as a 25- to 30-year venture. Many industry spokesmen and gas-market analysts still dismiss the current gas surplus as a "bubble," which will give way to new shortages once the national economy turns up and the inexorable decline they foresee in domestic gas reserves reasserts itself. The ANGTS sponsors implicitly endorsed such a view when they presented the testimony of Jensen Associates at the October 1981 Congressional hearings on the waiver package:

"Prior to new gas price decontrol in 1985, gas demand will grow in the price-sensitive industrial and power-generation sectors as the gap between gas and fuel oil remains. By 1983 this increasing demand will have absorbed the current gas supply surplus and exceeded available supply, creating an imbalance period lasting until decontrol of new gas prices in 1985."

The present glut and signs of market "disorder" (for example, the tendency of pipelines to shut in their relatively cheap gas in favor of producing highpriced gas subject to "take-or-pay" terms), are phenomena that are peculiar to the transition from regulation to deregulation. They will mostly disappear once producers and pipelines figure out how they ought to act in a free-enterprise environment where persistent "shortages" and "surpluses" are both impossible.

Today's surplus will not, in any case, give way to a new era of shortages and curtailments, nor is the rest of the outlook we have described likely to change unless Congress should re-regulate gas prices more strictly than has yet been publicly proposed by any substantial group of members.

The precise volume of new reserve additions of gas will not affect this situation, nor will it be affected by the strength and timing of a coming economic revival. Nor will the amount of additional gas conserved by homeowners be crucial. In fact, all we need to know for our conclusions is that gas markets are *now* clearing at boiler-fuel prices and that the marginal gas consumer in the United States will *continue to be* a boiler-fuel user for as far into the future as it is prudent for anyone in the energy industries to plan. Since *de facto* deregulation will permit highvalue gas users to bid whatever gas they need away from low-value users—

No addition to the nation's gas supply will be worth more than the cheapest fuel it displaces, whether that fuel be residual oil or coal.

With this understanding, the seven propositions listed above have the following further implications:

1. End of the Gas Shortage. Deregulation of wholesale gas prices is already a reality from the point of view of gas-distribution companies and many of the pipelines' direct-sales customers. No regulatory authority, state or federal, can now prevent the retail gas prices charged final consumers from rising to the highest levels the market will bear.

Such higher prices will limit demand, resulting in there being as much gas available in the market as any pipeline, distributor, or industrial gas-consumer will be willing to buy. No one now or in the future will have to buy gas he does not need today in order to stock up for future curtailments.

2. Value of Incremental Gas Supplies. Contrary to the expectations of most gas-industry personnel and government regulators during the 1970s, gas sales have topped out in most regions of the country at or below the price of an energy-equivalent amount of residual oil. The explanation is that the marginal gas consumer in the United States is a large industrial plant or an electric utility which burns it as boiler fuel.

More than half of U.S. gas sales in 1982 were to electric utilities and industry, and at least one quarter of the gas sold was burned in large industrial or electric-utility boilers. Thanks in part to the curtailments of the seventies, many of those consumers have now equipped themselves to burn an alternate fuel when it is cheaper than gas. In the most critical market sector, that substitute is residual fuel oil, and perhaps coal—not the more expensive No. 2 distillate oil that competes with gas for home-heating sales.

Thus, unless and until "premium" gas consumers actually bid the entire present supply away from boilers and other "low-priority" bulk-fuels uses, no pipeline or gas distributor can justify buying gas a any price higher than the energy-equivalent price of residual oil.

3. Lower-48 Natural Gas Supply Outlook. A pessimism generated by declining gas reserves throughout the 1970s still infuses most of the gassupply projections published in 1982 or 1983 by government agencies, trade associations, and forecasting institutions. However, annual additions to proved reserves of conventional gas in the Lower 48 have in fact been climbing steadily since 1978. The forecasters have thus far given little weight to this trend, but have instead preferred to focus on the declining volume of new gas reserves added per foot of drilling in new wells.

In both 1981 and 1982, annual reserve additions exceeded the year's production for the first time since 1967. The gas-producing industry compiled this record despite the existence of "partial" deregulation under NGPA, which diverted exploration effort away from the geologically most promising targets (where gas prices are still regulated) toward high-cost categories of gas that Congress exempted from price controls.

The forecasting establishment will not long ignore either the absolute growth in the nation's gas r serves or the dramatic increases in the ratio of dis coveries-to-drilling efforts that will show in 1982, and especially in 1983, when the market has fully eliminated the NGPA deep-gas premium. More optimistic

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gas-supply forecasts are likely to appear in the next few years.

4. Gas from Canada and Mexico. Because of domestic political inertia and the remnants of 1970sstyle thinking about gas markets, both the Canadian and Mexican governments are still demanding export prices higher than the market value of new gas in the United States.

Both Canada and Mexico, however, have a pressing fiscal need to find some formula that would make growing volumes of their gas economically acceptable in U.S. markets.

5. Exhaustion of the Old-Gas "Subsidy Cushion." There is no longer a "cushion" of cheap gas that can offset the high prices of imported gas, Alaska gas, or other "supplemental" supplies. More precisely, the cushion has already been incorporated in the prices of exempt domestic gas, the ceiling-price escalation schedules in the NGPA, existing import commitments, and in the expansion of transmission-company and gas-distributor rate bases.

Because pipeline companies are now recognizing this reality, no gas is saleable at a price above that which it could command in the market if it had to stand alone. Indeed, until the gas-transmission ompanies have worked or negotiated their way out of the excess volumes of gas they have already bought at above-market prices, the only gas they can afford to buy will be gas that is priced substantially lower than its value to the pipeline's most reluctant customer.

6. The Demise of Consumer Guarantees. In the 1970s (and even in the debate over the 1981 ANGTS "waiver package"), consumer guarantees were seen as an issue of equity, and "perfect tracking" was regarded as a technical legal issue. Both matters, however, are fundamentally economic issues which lose all force in a *de facto* deregulated market.

The exhaustion of the old-gas subsidy cushion means that minimum-bill and take-or-pay contracts by pipelines or distributors are no longer effective "consumer-payment" guarantees, no matter how perfect the "tracking" of these obligations to subsequent buyers may be in a legal sense. The only revenues a gas company can realistically commit in any contract with upstream suppliers are revenues which it can unquestionably collect from its own customers.

7. The End of Non-Recourse Project Financing. Because consumer guarantees are dead, non-recourse project financing is also dead unless government

arantees are forthcoming. In our 1978 studies for e Alaska Legislature, we found no knowledgeable person in the gas-producing or gas-transmission industries, investment banking, or the major institutional lenders (outside of Northwest Energy Company and its principal financial advisor Loeb Rhoades) who believed that ANGTS construction could be financed solely on the strength of gas-purchase contracts and pipeline tariffs. The subsequent revolution in U.S. natural-gas markets means that gas-purchase commitments are henceforth virtually worthless as security even for the pipeline's operational-phase financing, unless the debt is backstopped by the net worth of the sponsoring companies.

# The Downturn in World Oil Prices

A decline in constant-dollar oil prices began in 1981 and is now helping to speed up the convergence of gas and oil prices, and thus the emergence of a wholly new kind of gas market. The events that most industry and government analysts had not expected to occur until *after 1985* were speeded up even further by the general economic depression and continuing progress in energy conservation, which have combined to shrink the sales of all energy commodities.

Not long ago, almost all the well-known energy, industry, governmental, and private forecasting institutions predicted or assumed that constant-dollar crude-oil prices would continue to rise at least through the rest of this century. Large actual price rises in 1979, coupled with faith in ever-rising future oil prices also buttressed the economic credibility of ANGTS, even in the face of rising construction-cost estimates which seemed to indicate that the delivered price of Alaska gas might exceed its *current* market value (assumed to be the price of *distillate oil*, we must add) during the first few years of operation.

It is now apparent that the recent global oil surplus and the present price decline, already 2 years old, are quite unlike the "glut" and falling prices that occurred in 1975-78 between the two OPEC price upheavals. Perhaps the most telling sign and the real test of industry sentiment regarding the long-term energy outlook is *investment behavior*. Almost every synthetic-fuels project in North America has now been terminated, while the average market value of oil in the ground (proved reserves) in corporate acquisitions fell by more than half between late 1980 and mid-1982.<sup>4</sup>

In our view, oil prices will not likely surpass their 1981 peak within this decade, or perhaps within this century. The crucial issue for ANGTS today is not whether our own oil-market analyses prove correct, but the fact that *nobody is sure anymore*. Oil prices *might* conceivably go up once more, but the

<sup>&</sup>lt;sup>4</sup>See B.F. Picchi, "The Valuation of U.S. Petroleum Reserves: Exploding the Myths," in Salomon Brothers, Inc., *Stock Research/Industry Analysis*, October 15, 1982.

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near-consensus of a couple years ago that they *will* go up is in shambles. In middle 1983, it is easy to conclude that an investment whose viability *requires* a big increase in energy prices is an unacceptably risky investment.

Without the confidence of its potential backers that oil-price rises will exceed general inflation, ANGTS as now conceived cannot command confidence as an economic venture. It is unrealistic to expect that \$20 to \$50 billion (depending on the time at which the outlay is measured) can be assembled from private parties to finance the project.

## Inflation, Interest Rates, and Construction Costs

Inflation and Interest Rates. In their April 1982 statement announcing a 2-year delay in the ANGTS construction schedule, project sponsors attributed much of the difficulty to high interest rates and inflation. During the October 1981 Congressional hearings on the ANGTS "waiver" package, Northwest Energy Company Chairman John McMillian stated that "The biggest factor that has increased our cost over this period of the last 4 years has been the double-digit inflation and high interest costs."

Current and expected inflation rates are closely related to market rates of interest, and together they powerfully influence the economic outlook for ANGTS. However, *general inflation per se* is a neutral factor in project economics, because the availability of capital in nominal dollars and the current-dollar market value of gas can both be expected to increase more or less proportionately with prices generally. Inflation and high-interest rates *in combination*, however, have had several especially adverse effects.

General inflation rates that were rising between the Presidential Decision and 1981, caused a systematic *underestimation* of construction costs. In such a climate, the cost-escalation factors in project budgets never turned out to be big enough.

Higher rates of inflation also brought proportionally higher interest rates as lenders demanded nominal interest rates that would compensate them for the loss in the value of their principal, as well as pay an appropriate "real" return on their investment. If nominal rates rose just enough to offset inflation, they would not have affected the constant-dollar price of the project or its fixed costs per unit of gas transported, as seen over its entire economic life.

Under any given debt-amortization schedule and any given cost-of-service transportation tariff, however, higher interest rates meant that a larger part of the total "inflation premium" would have to be *collected in advance*, thus increasing the real-dollar cost of interest charges incurred during the construction period (AFUDC) and the early years of operation, and diminishing this cost in later years. This situation is especially troublesome for a project like ANGTS, whose most severe gas-marketability problems would in any case occur in its early years of operation.

In addition, nominal pre-tax rates of return to equity must increase *more* than proportionally to the rate of inflation if investors are to receive any real after-tax rate of return. This is because corporate income taxes are levied on the inflationary part of a corporation's book profits as well as on its real income. As market rates of return go up, in other words, the federal government's tax share of the real pre-tax profit increases.

Above and beyond these factors, however, *real* (inflation-adjusted) interest rates have recently been at or near historical high levels, and a combination of record federal budget deficits with a Federal Reserve policy of fighting inflation with tight money is likely to guarantee a continuation of comparatively high real interest rates. Table 1 shows the impact of these rates on the projected fixed-cost component of ANGTS gas prices.

Over the long term, the constant-dollar yields on high-grade industrial bonds, net of inflation, have tended to be less than 3 percent, and the after-tax real return on corporate equity has tended to be about 6 percent. Using the cost and financial assumptions by which the project sponsors and the Department of Energy have projected the ANGTS cost of service, but substituting inflation and interest rates typical of the 1960s (and a 1960s-style 7.5-percent after-tax return to equity in place of the 17.5 percent allowed by FERC), the average real cost of capital for ANGTS would be only 3.6 percent. This figure contrasts with an average real cost of capital exceeding 7 percent under both the high-inflation/high-interest and low-inflation/low-interest assumptions used by DOE.

The real cost of ANGTS capital implied by today's market expectations exceeds 13 percent. This is about four times the rates "normally" assumed for long-lived utility and public-works projects.

Our "current-market" assumptions generate a first-year 1983-dollar fixed cost for ANGTS incremental facilities of \$8.63 per thousand cubic feet (mcf), and the DOE high and low cases \$7.32 and \$5.64 per mcf, respectively. With interest and inflation rates from the 1960s, however, the first-yea fixed cost would have been only \$3.15 per mcf.

What went wrong with ANGTS, therefore, is partly attributable to high financing charges and the

#### Table 1

# **ANGTS Incremental Fixed Capital Costs**

Scenarios		Rates	Capital Costs After- Interest Tax Rate		Average Effective Capital Costs		As-built Const, <u>Costs</u>	Total Costs including <u>Const, Interest</u> 1989		First & sixth year fixed capital charges per MCF Straight-Line Amortization 1989 1995				Sixth Year Fixed Capital per MCF _ Levelized*
	(%)	(%)	. nate (%)	(%)	(%)	Real (%)	Current \$ (\$ bil.)	Current \$ (\$ bil.)	1983 \$ (\$ bil.)	1989 \$ (\$/mcf)	1983 \$ (\$/mcf)	1995 \$ (\$/mcf)	1983 \$ (\$/mcf)	\$ 1983 \$ ) (\$/mcf)
1. DOE High Infl. High Int. Case:	1				- <u>-</u> _								i	<u> </u>
U.S.	11	11	14	17.5	19.2	7.2	37.8	57.1	31.5	15.41	7.66	12.68	3.37	3.94
Canada	12	11	15	15										
2. DOE Low Inf./	,													
Low Int. Case:	_	_	~											
U.S.	7	5	8	17.5	13.4	7.5	31.9	43.0	29.6	9.01	5.91	7.75	3.79	5.19
Canada	8	5	9	1710	10.1	710	01.0	10.0	2010	0.01	0.01	7170	0.70	0.10
3. Current Market	t 6	5	12	16.0	19.2	13.3	30.2	44.8	33.0	12.68	9.04	10.24	5.37	7.08
4. Public Ownersh	nip 6	5	9	13.0	9.6	4.2	30.2	41.3	30.5	7.48	5.26	5.61	2.97	2.82
5. 1960s Conditio	ons 2	<sup>~</sup> 1.5	4	7.5	4.5	2.8	25.4	30.0	28.0	3.60	3.30	3.39	2.84	2.63

\*Amortization averaged over estimated life of project.

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Except as follows or otherwise specifically shown on the table, the assumptions are the same as in the Department of Energy's "Cost of Service for the Alaska Natural Gas Transportation System" (October 19, 1981). The analysis begins with the sponsors' cost filing as of that date, totalling \$23 billion 1980 dollars. In line with our intent to consider only the incremental capital cost, we have excluded \$3 billion from this figure, corresponding to the cost of the "prebuilt" Canadian segments and the U.S. Eastern and Western legs. The resulting \$20 billion 1980 dollars becomes \$24.2 billion 1983 dollars, at a price ratio of 1:1.21.

We assume that construction commences at the beginning of 1985 and is completed at the end of 1988; constant-dollar "as-built" costs are incurred at a level rate over the four years. These as-built construction costs are capitalized into the system rate base as of the beginning of 1989, when gas deliveries begin. The effective rate of corporate income taxes is 50 percent in both Alaska and Canada. Two billion cubic feet (bcf) of gas are delivered daily to pipelines in the Lower 48; capital costs per mcf are calculated on this basis.

The five scenarios are (1) DOE's high inflation/ high interest case; (2) DOE's low inflation/low interest case; (3) a "current" market case using expected rates of inflation approximating those now anticipated by forecasting organizations, a hypothetical 12-percent interest rate, and a 16 percent return to equity. There is also (4) a "public-ownership" scenario based on the same expected rates of inflation as in (3), interest on tax-exempt bonds at 9 percent, equity at the federal government's long-term borrowing rate (= the state of Alaska's risk-free opportunity cost rate for surplus funds), and the absence of federal or state tax liability. A "1960s-conditions" scenario (5) uses rates of inflation and interest rates characteristic of the period 1960-69, and a 7.5 percent return to equity (which was near the top of the range of rates permitted by utility commissions using an original-cost rate base). The two scenarios from DOE assume 75 percent debt and 25 percent equity. Because the highly leveraged capital structure now contemplated by the ANGTS sponsors requires either consumers or a creditworthy third party (like the federal government) to assume construction and market risk, and because we have concluded that neither of these circumstances is likely, the "current-market," "public ownership," and "1960s conditions" scenarios assume a more conventional 50-50 capital structure.

impact of expected inflation on cost overruns and the risk of project abandonment. General economic trends, however, suggest that—

The outlook for ANGTS from the standpoint of construction costs and overrun risks (both sensitive to interest rates and inflation) is likely to improve (or at least not worsen) with time.

However, the fact that inflation and interest rates are now falling does not necessarily mean that the overall cost outlook for ANGTS will improve. Lower rates of construction-cost inflation will reduce the likelihood of cost overruns, and lower rates of *expected* inflation built into nominal interest rates will moderate the front-end tilt in recovery of fixed costs under conventional utility tariffs. However, for falling rates to make a significant impact on project economics, the *real cost* of capital must fall: the nominal interest rates that apply to the project must decline faster than expected inflation rates, but there is no indication that this will happen.

The prospect of falling inflation rates generates still another danger to the viability of ANGTS—the risk that financing will be arranged at high interest rates and equity rates of return corresponding to recent high rates of inflation, but that inflation will settle at a much lower level, leaving the enterprise with a high nominal cost of service generated by high interest rates, but with substantially lower gas-market values than the sponsors anticipated.

# Paradoxically, therefore, an outlook favoring falling inflation and interest rates does not necessarily improve prospects of ANGTS.

Construction Costs. One adverse influence on the economic assessment of ANGTS has been a series of increases in its expected construction cost. Only a few years ago, the ANGTS sponsors and their financial advisors viewed rising design costs and the risks of overruns above design estimates as *financing* rather than *marketing* problems; today, we know they are obviously both. On this issue, in contrast to several others, however, the future could hold some pleasant surprises. While the combination of *present* cost estimates with foreseeable gas-market conditions and present and foreseeable interest rates now appears fatal to ANGTS—

1. We do not regard the prospect of everrising constant-dollar construction-cost estimates as a major economic hazard for the project, and

2. Present construction-cost estimates are at least as likely to be overstated as understated, particularly when costs are measured against the

# amount of gas to be transported.

Macroeconomic Influences. Construction-cost overruns tend to be frequent and comparatively large in periods when inflation is *accelerating* and also when environmental, safety, and other kinds of regulation are getting more complex and demanding. In periods of above-average real economic growth, moreover, the wages of construction workers tend to rise more rapidly than wages in other industries. Finally, accelerating inflation also generally means rising interest rates, which result in higher interim financing costs (in utility parlance "allowance for funds used during construction" or AFUDC). Thus, accelerating inflation causes final project costs to increase even faster than the wages of construction labor and the cost of building materials.

As all these conditions occurred in the 1960s and 1970s, it is not surprising that the experience of these decades fostered a belief that big constructioncost overruns are the rule rather than the exception in large projects.

In our view, however:

The economic and regulatory forces that generated the construction-cost overruns of the 1970s have largely run their course.

General inflation has already decelerated sharply and is likely to remain relatively low throughout the 1980s (meaning that escalation rates built into construction-cost estimates will typically be too high rather than too low). This trend probably means lower nominal interest rates as well and, as a result, pre-construction estimates of interim-financing costs (AFUDC) will tend to be too high. Real economic growth rates are likely to be lower than in the 1960s and 1970s, moreover, causing the construction-cost indices to increase less rapidly than general inflation.

Environmental and safety regulations will also tend to impact costs and schedules less severely than at present. While we do not anticipate a significant retreat from the *goals* that motivate today's environmental and safety dictates, regulatory *practice* will probably tend to be more sensitive to cost-effectiveness criteria and on balance less dilatory. At any rate, it is not likely that delays and cost-escalation engendered by these kinds of regulation will continue to *grow* as they did in the last two decades.

Real Costs and the "Incentive Rate of Return." A substantial part of the increase in expected ANGTS costs has a physical (or engineering), as opposed to "macroeconomic," origin. The ANGTS sponsors hav increased their estimates of the amount of labor, materials, and other real inputs to the project. It is lifficult to determine, however, how much of the real cost increase was inescapable and how much (if any) has been due to peculiar incentives created by the regulatory system.

One factor that suggests that ANGTS might come in on (or even under) its constant-dollar "asbuilt" budget, however, is the existence of the "Incentive Rate of Return" (IROR) specially designed and specially prescribed for the Alaska gas pipeline.

Professor Walter Mead in a 1977 report, concerned that existing incentives might induce competing applicants to understate estimated project costs, proposed the IROR as a way to smoke out the true costs of an Alaska gas pipeline.<sup>5</sup> Instead of allowing the sponsors the same percentage return on investment regardless of the project's ultimate cost, Mead proposed a rate-of-return rule that would adjust the owners' profit in order to reward them for coming in under budget and penalize them for cost overruns. The argument for this concept was evidently persuasive, and President Carter mandated it in his 1977 decision.<sup>6</sup>

We are not in a position to estimate how much overbuilding, redundancy, and waste (if any) are contained in the ANGTS sponsors' most recent cost rojections, or the degree to which the IROR has encouraged or failed to discourage them. The perverse incentives created by the IROR have not escaped public attention, however, and important parties, including some ANGTS sponsors, *believe* that the IROR has been a major reason for design-cost escalation.<sup>7</sup>

<sup>6</sup>In practice, however, the net effect of the IROR on construction costs is quite uncertain, and may in fact be perverse. In conformity with the purpose of the scheme, the Federal Energy Regulatory Commission (FERC) at first tried to use the cost estimates in Alcan's original application as the basecost figure for calculating the IROR. Ultimately, however, the commission acceded to the sponsors' demand that the IROR be based on the "final" design-cost estimate approved by FERC. Under this rule, one effect of the IROR is to shift any reward that otherwise would exist for overbuilding or waste from the construction phase back to the design phase.

<sup>7</sup>Officials of one gas transmission company confided to the authors a belief that their own engineering department could design and build the Alaska pipeline segment for as little as 60 percent of the present budget, and that the cost of the remaining unbuilt Canadian portion could be reduced about 30 per-

nt by returning to the original 1976 "Alcan" concept, which ended to save money by maximizing the use of existing peline segments in Alberta and British Columbia, as opposed to the plan adopted in 1977 for a brand-new "express line" through Canada. The revolution in gas-market structure and behavior described earlier would dictate a major change in the financing strategy for ANGTS regardless of anticipated construction costs or their relationship to the long-term market value of Alaska gas. The potential for reducing capital costs per unit of gas carried by redesigning the system for a larger throughput may, moreover, require substantial design changes.

In either case—a reorganization or redesign of the project—the most effective incentive for costcontrol in both the *design and construction* phases would probably be the approach proposed by the New York Public Service Commission in the 1976 Federal Power Commission proceedings to select a pipeline route and sponsor: deregulate both the wellhead price of Alaska gas and the rate of return to pipeline equity. Under those circumstances, the cost of overbuilding, gold-plating, waste, bad management, or bad judgment would fall directly on the sponsors, who would also reap any rewards for economy and good judgment.

> Perhaps the best way to vanquish the incentives favoring cost-inflation created by utilitystyle regulation would have been simply to deregulate the entire system, from wellhead to city-gate.

# FIFTEEN RULES FOR A VIABLE PROJECT

The existing ANGTS concept and organization have been battered by (a) changed perceptions of need for the project stemming from a revolution in gas-market structure and behavior, (b) a loss of confidence by industry and potential lenders that real crude-oil prices are certain to resume their upward course, (c) inflation and high interest rates. However, these developments singly or in combination are not necessarily fatal to the concept of a pipeline across Canada for Alaska natural gas.

Even if the underlying economics of the ANGTS concept remained sound, radical changes would be necessary in the project's organization and contemplated financing and marketing strategy. In our view, any successful project will have to conform to the following rules:

 Because the old-gas "cushion" is gone or nearly so, North Slope natural gas must be marketable on its own in Lower-48 markets. It is not viable if the project must depend on any implicit subsidy via rolled-in pricing.<sup>8</sup>

<sup>&</sup>lt;sup>5</sup>W.J. Mead, Transporting Natural Gas from the Arctic: The Alternative Systems, American Enterprise Institute, 1977.

<sup>&</sup>lt;sup>8</sup>"Rolled-in pricing" refers to the practice of averaging the different purchase prices of gas from several sources and selling at a single price based on this average.

- 2. North Slope gas must have a competitive delivered price over its entire economic life. The exhaustion of the old-gas cushion means that a conventional front-end-loaded rate design (reflecting straight-line amortization of debt and equity capital) would be unworkable for ANGTS.
- 3. Because the marginal gas consumer in the United States uses gas as a boiler fuel and has the option of substituting some other fuel, the value of North Slope gas in Lower-48 markets will be no higher than the price of the boiler fuel it displaces.
- 4. A reasonable indicator of the current finalmarket value of natural gas is the monthly list of "Alternative Fuel Price Ceilings" that the Energy Information Administration (EIA) submits to FERC for the purpose of carrying out the incremental-pricing provisions of the NGPA. In June 1983, these prices ranged between \$3.21 and \$3.96 per million btu. For purposes of this analysis, we assume \$3.50 per million btu to be a reasonable approximation of the incremental value of natural gas in the United States today.
- 5. Regardless of how little new natural gas may be discovered and produced in the Lower-48, and regardless of the volumes of gas that may be imported from Canada and Mexico, the marginal consumer of gas in the United States will remain a boiler-fuel user for the rest of this century.

Regardless of the gas-supply outlook, therefore, the wholesale (wellhead or border) price of gas will *not* reflect the price of distillate oil prices. The volume of imported and domestic gas supplied will, however, determine *what* boiler fuel determines the market value of natural gas—i.e., whether gas competes at the margin with low-sulfur residual oil, high-sulfur residual oil, or coal.

- 6. It is impossible to count on a resumption of increases in constant-dollar oil prices. Indeed, no large-scale energy project is a prudent investment unless it can remain competitive under constant-dollar oil prices considerably *lower* than those that prevail today.
- 7. These principles together imply that:

(a) ANGTS is not a viable enterprise if the absolutely irreducible costs of Alaska gas delivered into the existing North American gastransportation network exceed \$3.50 pe mmbtu (1983 dollars);

(b) ANGTS faces an insuperable marketability hurdle if those costs exceed \$3.50 in any year of its economic life, and

(c) ANGTS is too risky to be financed without direct governmental guarantees and/ or subsidies, unless the average cost of Alaska gas is expected to be *comfortably less* than \$3.50 per mmbtu.

- 8. Because the average retail price of gas will henceforth be a market-clearing price, regulated gas companies will be unable to guarantee payments for expensive gas. "Consumer guarantees" and "perfect tracking" are now worthless as security for financing projects that deliver gas at a cost that may exceed its market value.
- 9. Because downstream gas purchasers can no longer offer credible "all-events," "minimum-bill," or "take-or-pay" commitments for gas priced above its final market value, non-recourse project financing is no longer viable as a method of funding supplementalgas projects.
- 10. Because final-consumer markets have cleared (leaving no existing backlog of demand), there is no longer any way to guarantee the tracking of upstream charges specified in contracts or regulations. Thus, gas producers will henceforth be "price-takers" and wellhead prices will be determined only on a netback basis. North Slope gas that is priced above the cost of fuel in Lower-48 boilerfuel markets will be unsaleable.
- 11. Any viable organizational and regulatory scheme for ANGTS must incorporate the netback pricing principle. In other words, the North Slope gas producers and the State of Alaska cannot expect to receive more than the wellhead value of their gas, which is the residual after conditioning and transportation costs are subtracted from the Lower-48 final-market value.
- 12. As "price-takers" (residual claimants to the value of North Slope gas), the gas producers and the State of Alaska have the greatest stake in construction of ANGTS or a su cessor system, and especially in optimizin, its design and controlling its costs.
- 13. As "price-takers," the North Slope pro-

ducers and the State of Alaka must be the first guarantors of any debt, at least to the extent of their gas-sales revenues, even if that exposure is not made explicit.

- 14. If, however, there is a chance that reduction of wellhead revenues to zero might still result in a deficiency in the scheduled principal and interest payments to lenders, then the financeability of ANGTS will depend on an *explicit* dedication of producer and state assets.
- 15. If the expected rewards to the producers and the state are not large enough and secure enough to induce them to provide adequate backing for the debt, then only a federal guarantee has a reasonable chance of making up the shortfall.

Under virtually all of the foregoing rules, ANGTS as now contemplated is unworkable. The economic rationale incorporated in the ANGTSsponsors' organizational and financing strategy, in the 1977 Presidential Decision, in the subsequent decisions of FERC, and in the 1981 "waiver" package, lead to totally unacceptable Lower-48 gas prices. The epartment of Energy's report on the "Cost of Serice for the Alaska Natural Gas Transportation System" (October 19, 1981) projects a first-year 1980 constant-dollar cost of \$7.69 to \$8.93 per mmbtu— \$9.34 to \$10.85 in 1983 dollars. Other projections result in somewhat different figures, but they *all* exceed any current or reasonably foreseeable gas-market value. In short—

There is no chance that ANGTS will be financed, built, and go into operation under the present program.

The most obvious obstacle to marketing North Slope gas is the "front-end-loaded" rate profile that flows from the assumption that debt and equity investments would be amortized on a straight-line basis. Restructuring the debt-service schedule and tariff to eliminate their front-end load, however, would not be sufficient to make ANGTS economically viable under the present strategy and rules. DOE's projection of average real gas prices over 20 years ranges from \$4.23 to \$4.67 per mmbtu in 1980 dollars (\$5.18 to \$4.99 in 1983 dollars).

#### THE ULTIMATE QUESTION

There is one fundamental economic question oout ANGTS that determines whether it merits further questions about project organization, financial structure, rate profiles, or regulatory treatment: Is there any reasonable hope that the irreducible cost of producing, conditioning, and delivering Alaska gas to Lower-48 consumers can be held under \$3.50 per million btu in 1983 dollars?

If the answer is yes, then the answer to a corollary question determines whether there is any real prospect the system will be financed and built (at least without direct federal aid):

Is the expected margin between \$3.50 per mmbtu and the irreducible delivered cost of the gas wide enough to induce the North Slope gas producers and the State of Alaska to take the risk that their net returns will be negative?

Incremental Fixed-Capital Costs of ANGTS per Unit of Gas Delivered. The *irreducible* cost of service is one that does not provide any wellhead return,<sup>9</sup> any royalty or severance-tax payments, any *advalorem* taxes on pipeline property in Alaska or Canada, or any allocation of fixed costs on existing facilities, including the "prebuilt" southern sections of ANGTS.

Table 1 shows the total fixed costs and fixed costs per thousand cubic feet (mcf—slightly more than 1 mmbtu) under the sponsors' latest budget and presents a number of assumptions about inflation and financing costs. This table contains every economically unavoidable cost (except operation and maintenance [O&M] costs) other than field and pump-station fuel which, in line with the zero wellhead-price assumption, is assumed to be costless. O&M costs other than fuel are likely to be on the order of 40 cents to 75 cents per mmbtu (or mcf) in 1983 dollars. With O&M costs at a conservative 50 cents, no system could be viable if its incremental fixed costs in 1983 dollars exceeded \$3.00 per mcf.

The only scenarios that meet this test and, indeed, just barely meet it, are (1) a world with inflation and interest rates like those that prevailed during the 1960s, and (2) a "public-ownership" scenario in which the sponsors borrow in tax-exempt bond markets (and under the questionable assumption that the volume of ANGTS tax-exempt borrowing would not lift interest rates in those markets to equivalence with yields on taxable securities) and in which ANGTS "profits" are not subject to federal or state income taxes. The latter scenario is totally unrealistic (for one thing, it applies the same parameters to the Can-

<sup>&</sup>lt;sup>9</sup>Except for the incremental costs of field development, which appear to be *negative* at Prudhoe Bay because production and sale of the gas would avoid the need to make further investments for the purpose of continued reinjection of the gas.

adian segments as to those in Alaska), but it sets the outer limits to cost reductions that could be achieved by industrial-development bonding, a state equity participation, or other tax-avoidance measures.

The economic conditions of the 1960s would result in a first-year fixed charge of \$3.30 per mcf; a sixth-year charge of \$2.84, and a 20-year average of \$2.63, all in 1983 dollars. The public-ownership scenario generates unit charges of \$5.26, \$2.94, and \$2.82 respectively.

Economies of Scale: Reducing Unit Costs by Increasing Gas Deliveries. The Prudhoe Bay reservoir is obviously not the only conceivable source of gas in Arctic Alaska. The most promising measure for reducing real fixed costs per unit of gas would be a project designed to carry more gas from the North Slope than the 2 billion cubic feet per day (bcf/d) contemplated by the sponsors and assumed in these calculations. A flow of 4 bcf/d, and capital costs increased by the engineering rule of thumb for pipelines and process vessels that says fixed costs tend to increase with the sixtenths' power of capacity, yield the following values:

The economic conditions of the 1960s would result in a first-year fixed charge of \$2.50 per mcf; a sixth-year charge of \$2.15, and a 20-year average of \$1.99, all in 1983 dollars. The

public-ownership scenario generates unit charge of \$3.98, \$2.23, and \$2.14, respectively.

With \$3.50 as a reference price, there is little margin in any of the scenarios for cost-overruns, for a further decline in real oil-price levels, or for a long-term rate of inflation below the 5 percent assumed in the calculation.

These figures, moreover, do not provide for any wellhead price, any royalty or severance tax, or any *ad valorem* tax on ANGTS property in either Alaska or Canada. (With DOE's "low-low" scenario, for example, Alaska's 20-mill *ad valorem* property tax on oil and gas properties alone would average 96 cents per mcf in 1983 constant dollars over the first 20 years of pipeline operation.) The unit fixed-cost figures in Table 1 appear, therefore, to offer almost no incentive for the gas producers or the State of Alaska (which, we assume, would be the project sponsor in the "public-ownership" scenario) in return for the risk and effort they would have to undertake in order to get the pipeline built and into operation.

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