1092 HRES FERC, REVIEW OF ANGTS

Alternatively, these gas customers might compare the lifecycle costs of Alaskan gas with the similar costs of their other energy options.[4] On this basis, the annuity-equivalent prices for a million Btu of distillate fuel oil (assuming the low cost escalation scenario) versus Alaskan gas (for a 25 year period) would be as follows:

| | |
|---|---|
| Alaskan Gas (citygate) | $3.18 (mid-1979 dollars) |
| Distillate Fuel Oil (wholesale) | $3.60[5] |

Thus, energy users comparing a 25-year contract for distillate fuel or Alaskan gas would prefer Alaskan gas, other things being equal. Moreover, if distillate fuel oil prices were to rise according to the medium oil price escalation scenario, the Alaskan gas would look even more attractive:

| | |
|---|---|
| Alaskan Gas (citygate) | $3.18 (mid-1979 dollars) |
| Distillate Fuel Oil (wholesale) | $4.41 |

THE MEXICAN GAS OPTION

Alaskan gas differs significantly from additional gas imports from Mexico or Canada. From the U.S. consumer's perspective, Alaskan gas would resemble a capital intensive project whose cost would be largely fixed while Mexican gas would resemble a project with high variable costs whose annual level would

4/ The President's Decision emphasized the displacement of wholesale distillate fuel oil by Alaskan gas. This emphasis on wholesale transactions is continued in this analysis of the market position of Alaskan gas; thus, any differences in costs for distribution of gas or oil to end users are not treated here.

5/ This is the distillate fuel oil annuity-equivalent the price projection used to develop the gas value in the NNEB calculations.

depend upon the price of a reference petroleum product.[6/] Other important differences include any national security consequences of domestic versus imported gas supplies and the possible influence of Mexican gas purchase arrangements, especially the price terms, on other energy supplies, particularly Canadian gas and Mexican oil.

Alaskan Versus Mexican Gas

The relationship between the costs of Alaskan and Mexican gas is traced over time in Figure IV-2. Clearly, a comparison of first-year costs tells a misleading story. As Table IV-1 illustrates, over a 25-year period consumers would prefer the Alaskan gas to the Mexican gas even if the Mexican gas price were tied to the residual fuel oil price.[7/] Table IV-2 compares the total costs to consumers for streams of Mexican and Alaskan gas, both delivered at the flow rate projected for the ANGTS. The present value of the savings available to consumers from Alaskan gas is significant, $13.2 billion (mid-1979 dollars), under the assumption that Mexican gas prices would be referenced to distillate (under low oil price escalation).

Even under the high construction cost ANGTS case, consumers would prefer Alaskan gas to Mexican gas pegged to distillate prices. Finally, the high

6/ Mexico has proposed distillate fuel, landed in New York harbor, as the reference price for its gas delivered at the U.S. border. The U.S., howeverr, has countered that domestic transportation costs from the border to the burner tip, added on top of a distillate-equivalent price, would render Mexican gas economically unattractive because it will be forced to compete with residual fuel oil in the U.S. industrial boiler market.

7/ This comparison is made at the citygate where the ANGTS would deliver Alaskan gas, and assumes that Alaskan gas is delivered at base case estimated costs.

FIGURE IV-2

ALASKAN VERSUS MEXICAN GAS COSTS OVER PROJECT LIFE[a/]
(1979 dollars)

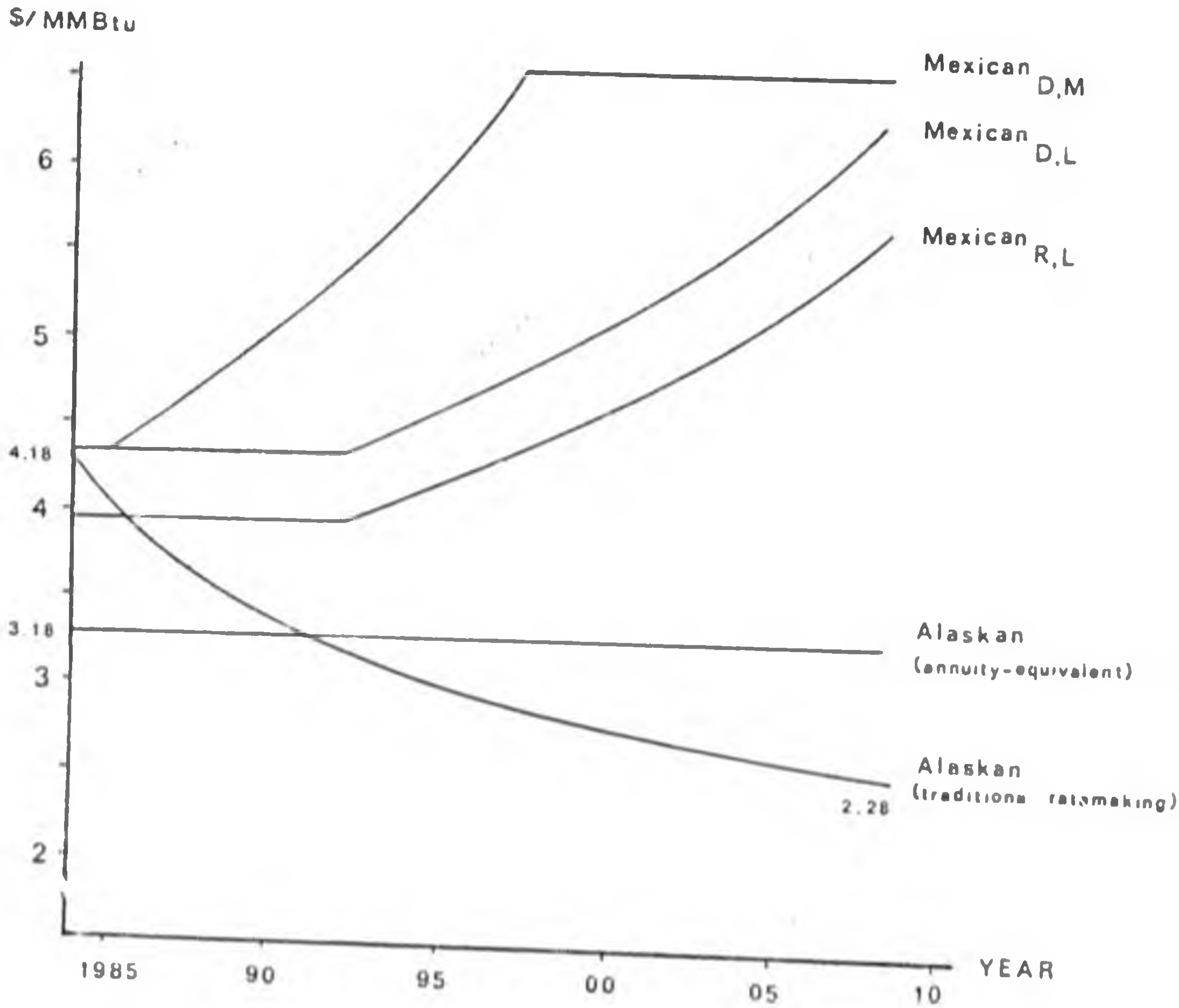


TABLE IV-1

COMPARISON OF ANNUITY-EQUIVALENT DELIVERED COSTS
FOR ALASKAN AND MEXICAN GAS

| Supply Source | Annuity-Equivalent Cost[a/] (mid-1979 dollars per mmBtu) (6% discount rate) |
|---|---|
| ANGTS | |
| Base Case | $3.18 |
| High Cost | 3.55 |
| Mexico | |
| Distillate Price, Low Escalation | 4.61 |
| Distillate Price, Medium Escalation | 5.46 |
| Residual Price, Low Escalation | 4.25 |

a/ 25-year annuity-equivalent, at midwestern citygate; delivered volumes projected for ANGTS.

TABLE IV-2

COMPARISON OF TOTAL "LIFECYCLE" DELIVERED COSTS
FOR ALASKAN AND MEXICAN GAS
($ billion, mid-1979)

| Supply Source | Total Lifecycle Costs[a/] | |
|---|---|---|
| | (6% rate) | (10% rate) |
| ANGTS | | |
| Base Case | 29.4 | 18.8 |
| High Cost | 32.8 | 21.1 |
| Mexico | | |
| Distillate Price, Low Escalation | 42.6 | 25.4 |
| Distillate Price, Medium Escalation | 50.5 | 29.8 |
| Residual Price, Low Escalation | 39.3 | 23.5 |

a/ 25 years, at midwestern citygate, delivered volumes projected for ANGTS.

cost ANGTS case, as shown in Table IV-2, still compares favorably to Mexican gas tied to residual fuel oil, even under low world price escalation.

Thus, the Alaskan gas supply option appears likely to provide gas customers with an economically superior alternative to Mexican gas.8/ At least one important potential benefit from Mexican gas sales, however, is omitted in the above analysis, the effect of an agreement to purchase Mexican gas (or the lack of such an agreement) on the availability of Mexican oil. Yet, as the lifecycle cost comparisons of Table IV-2 indicate, under the base case assumptions consumers would have to save more than $13.2 billion on oil purchases to be compensated for the cost penalty they would incur through enforced purchases of Mexican rather than Alaskan gas. Mexico probably would offer its oil to U.S. purchasers at prices close to world prices. Consequently, direct economic efficiency benefits in the U.S. energy sector from Mexican oil deals alone may not attain such magnitudes and U.S. policymakers would need to look to other sectors or other effects, such as national security, to prefer Mexican gas over Alaskan gas.

Importantly, the purchase of Mexican gas supplies could also trigger cost increases for U.S. imports of Canadian gas. The cost of Canadian gas imports averaged approximately $2.16 per Mcf in 1978 (approximately $2.09 per million

---

8/ It is worth noting at this point that the recent Congressional Research Service (CRS) analysis of Mexican gas and oil, referenced earlier, came to the opposite conclusion about Alaskan gas because the CRS compared the two sources only on the basis of 1985 costs. In 1985, Alaskan costs would exceed Mexican because almost all of the ANGTS rate base is included while neither the real cost escalation in later years for Mexican gas nor the transportation costs to move Mexican gas to users were incorporated in the comparison.

Btu).[9/] At the current level of gas imports, one trillion cubic feet annually, a Canadian demand for price parity at the border with Mexican gas would increase the cost of their gas by over one billion dollars (mid-1979) annually, or approximately $12 billion on a present value basis for a 25-year supply.[10/]

But as suggested earlier, direct consumer or national economic efficiency benefits of larger energy purchases from Mexico may not be the consequences of most importance to U.S. policy. Instead, enhanced security of supplies, provided by a geographically closer and robust economic partner, and greater diversification away from Arab oil supplies may be the most important national benefits. But a preference for Mexican rather than Alaskan gas would require a judgement that consumer plus other national benefits from access to Mexican oil and gas exceed the $24.2 billion of NNEB lost when choosing Mexican gas over Alaskan.[11/]

Rephrasing the Question

This analysis demonstrates that, under the narrow criterion of national economic efficiency in the U.S. energy sector, Alaskan gas would provide greater benefits than Mexican gas. As noted, our analysis does not grapple with the potentially more important issue of the benefits of any Mexican

9/ DOE/EIA-0147/8, Table 4, actually lists "Canadian and foreign" supplies.

10/ "Canada gas-export issue grows hotter," Oil and Gas Journal, October 9, 1978, p. 48.

11/ This figure is estimated by using the Mexican gas prices and the Alaska gas value in the NNEB calculation.

gas/oil linkage and its implications for U.S. oil imports strategy or even broader U.S. interests regarding trade and other matters of importance.

In this broader context, the question remains open whether the United States might benefit most from proceeding with both Alaskan and Mexican gas supply projects. Our logic in the Mexican versus Alaskan gas comparison does not illuminate the choice between Mexican gas and oil versus OPEC oil. The results only indicate that the Alaskan gas pipeline project should proceed. But policymakers could also judge the national interest to be well served by purchasing Mexican gas, for example, in order to reduce dependence on Middle East oil. This reduction could occur in two ways: (i) Mexican gas could substitute for oil consumption, and (ii) Mexican oil could replace OPEC oil. In this context, phrasing the question as a choice of either Mexican gas or Alaskan gas might frustrate policymaking. Rephrased, the more germane question concerns the attractiveness of Mexican energy on its own merits across the entire spectrum of the U.S. energy market and of our international affairs.

ALASKAN GAS AND ALTERNATIVE ENERGY SOURCES

In addition to understanding how Alaskan gas compares with distillate fuel oil and Mexican gas, it is also important to explore the implications of its substitution for other energy forms. Our earlie NNEB calculations set the value of Alaskan gas at the cost of distillate. Implicit in this valuation is the assumption that this gas would displace an energy-equivalent amount of distillate fuel. But Alaskan gas could substitute for other energy forms as well, which could lead to a substantially different estimate of the NNEB.

The assumption that Alaskan gas substitutes for distillate fuel sold at wholesale prices implies that large industrial operations are the marginal user of additional gas supplies. The choice of this assumption was based on a desire to maintain consistency with this one key assumption in the analyses associated with the President's Decision. Importantly, it is not a forecast that Alaskan gas, in fact, will be consumed by industry or, if consumed there, will displace distillate rather than residual fuel. If gas supplies were to tighten, Alaskan gas might displace other energy use. If the substitution occurred in the residential sector, the alternative fuel could be electricity, which is more costly than distillate fuel oil for certain residential uses not requiring electricity's special properties. To the extent Alaskan gas replaced such higher cost energy supplies, the NNEB would increase, and all of the additional benefits would be captured by consumers.

If, in contrast, gas supplies were quite plentiful and inexpensive during the 25-year life of the ANGTS, Alaskan gas might displace industrial boiler fuels costing less than distillate, such as residual fuel oil. If the value of Alaskan gas deliveries were equated with projected prices of residual (under a low escalation scenario), the NNEB estimate would shrink by $3.1 billion from the base case to a $11.8 billion level.

MARKET PROSPECTS FOR ALASKAN GAS

Table IV-3 (Column A) indicates that the nation would receive substantial benefits from the development of the Alaskan gas pipeline project even if the gas were valued at the cost of residual fuel oil and if construction of the ANGTS were to experience high cost overruns. Nevertheless, the project might

TABLE IV-3

BENEFITS OF ALASKAN GAS RELATIVE TO SELECTED ALTERNATIVE FUEL OPTIONS
(mid-1979 dollars)

| Energy Source Assumed Replaced[a/] | (A) NNEB | (B) Consumer Lifecycle Cash Savings |
|---|---|---|
| Base Case Cost: | | |
| Distillate Fuel Oil | $14.9 billion | $3.9 billion |
| Residual Fuel Oil | 11.8 | 0.8 |
| High Cost: | | |
| Distillate Fuel Oil | 10.4 | 0.5 |
| Residual Fuel Oil | 7.3 | 2.6 |

a/ All fuel prices are assumed to follow low price trajectories as defined in Table II-1.

not attract potential gas customers who can obtain and use residual fuel oil. The reasons for this apparent contradiction include:

- the accrual, under base case assumptions, of most of the project's benefits to parties other than consumers, and
- the market disadvantage faced by Alaskan gas in the early years of the project stemming from traditional gas ratemaking methods.

Table IV-3 (Column B) illustrates the relative market attractiveness of Alaskan gas on the basis of lifecycle costs. Based on this comparison, energy consumers would be better off over the next 25 years with Alaskan gas than with either distillate or residual oil under the base case cost assumptions. Under the high cost ANGTS case, however, consumers would prefer Alaskan gas compared only with either distillate fuel oil (low price escalation) or more costly alternatives.

## THE ANGTS DELAY OPTION

Suppose that the marketability of Alaskan gas hinged on the need to make its first-year delivered costs less than or equal to the price of distillate fuel oil. This supposition, coupled with the upside-down cost patterns caused by traditional ratemaking, would mean that Alaskan gas would not be marketable until distillate fuel oil prices reached $4.18 per million Btu (1979 dollars), which would not occur until 2002 under the base case assumptions or until 1991 under the medium oil price escalation assumption. The policy option implicit in this supposition--deferring the ANGTS well into the future--would cause significant economic loss from the national perspective.

When considering project delays of several years, the uncertainties associated with estimating project costs and gas value are compounded significantly compared to the estimating problems already present for the base case. Nevertheless, despite the fact that no precise estimate of how a long delay might affect the NNEB is possible, an approximation can be made. For the low price escalation scenario described in Table II-1, applying the 6 percent discount rate would yield the following NNEB decreases through delay:

| Years Delay | NNEB Loss |
|---|---|
| 5 | $1.5 (mid-1979 dollars) |
| 10 | $2.6 |
| 15 | $4.1 |

Although these estimates are rough, they suggest that delay of the project in order to improve the prospects for initial marketability could generate some loss in national benefits.

Analyzing the NNEB to the nation as a whole has thus far helped to make this analysis more managable. In the next section, the question of how the NNEB would be distributed among sectors of the economy is explored.

## V. THE DISTRIBUTION OF ALASKAN GAS COSTS AND BENEFITS

The assertions that the Alaskan gas pipeline project offers significant economic advantages and that the project can only r ceed if offered special regulatory treatment appear to contradict each other. This apparent contradiction, however, stems from the nature of the uncertainties associated with this project and from the allocation of the accompanying opportunities and risks, as well as other project costs and benefits, among the project's participants.

In preceding sections, this analysis has dealt with project costs and benefits on an aggregate level, finding that the nation or consumers as a whole could receive substantial benefits from this project if current estimates are correct. But these costs and benefits will not acc e to all members of the economy in equal proportions. Consequently, it is important to identify more specifically who pays the project costs and who receives the project benefits.

This section begins by discussing how the base case NNEB would be distributed among the major participants of the project. Next, it considers the distribution of the NNEB under other conditions. Then, the opportunities and risks associated with the proposed pipeline are addressed. The section concludes with an examination of how the FERC regulations applied to the project could modify and allocate these opportunities and risks.

DISTRIBUTION OF NNEB

The net national economic benefits from the ANGTS project would be shared among gas consumers, Prudhoe Bay gas producers, the Alaskan government, the federal government, and pipeline owners. The net benefits captured by each of the participants would consist of the following:

Consumers: Consumer benefits consist of any savings from purchasing Alaskan gas instead of an alternative fuel.

Gas producers (domestic): Producer benefits accrue from the price received for the gas produced minus incremental production and gathering costs, incremental gas conditioning costs, royalty payments, and taxes (severance and income), further reduced by the benefits flowing to foreign interests.

Alaskan state government: Certain tax payments to Alaska are assumed to be surrogate measures of the real resource costs incurred to support the ANGTS. Revenues in excess of those required to cover such costs represent net benefits captured by Alaska. These include royalty payments plus severance and income taxes on producer revenues in excess of the incremental costs noted directly above.

Federal government: Taxes on a normal level of producer profits are also considered a surrogate for the real resource costs incurred across the overall U.S. economy to support the ANGTS. Federal income taxes levied on above-normal producer profits represent the share of the project's net benefits captured by the federal government and, in turn, the general taxpayer.

Pipeline Owners: Because the ANGTS would b regulated as a utility, its cost of service revenues would be "normal," by definition. The pipeline owners, however, are affected by an investment tax credit on the ANGTS segments constructed in the United States. This credit can be interpreted as capturing a share of the NNEB for pipeline owners because Internal Revenue Service and FERC rulings do not allow these credits to be flowed-through to consumers as they are received.[1/]

1/ Appendix F describes the methodology for calculating the NNEB shares in greater detail than provided by these five brief summaries of the benefits accruing to each of the major ANGTS participants.

Expected Benefits

Under the base case assumptions used throughout this analysis, the NNEB is expected to be $14.9 billion (mid-1979 dollars). This net benefit would be shared as follows:

| | |
|---|---|
| Consumers | $ 2.7 billion (mid-1979) |
| Domestic Producers | 3.7 |
| Alaska | 4.7 |
| Federal | 3.5 |
| Pipeline Owners | 0.2 |
| Total NNEB | $14.9 billion |

At the maximum wellhead price for Prudhoe Bay unit gas set by the NGPA, gas producer revenues would exceed their expected incremental production costs. In turn, this would allow gas producers and the Alaska and federal governments collectively to capture 80 percent of the base case NNEB. Among the major beneficiaries, the Alaska government would receive the largest share (32 percent of the NNEB). Gas producers would receive the next largest share (25 percent), followed by the federal government (23 percent). Under the base case, gas consumers would obtain a relatively moderate share of the NNEB (18 percent), and pipeline owners would receive a minor portion (2 percent).

Our base case assumes a 6 percent discount rate. Under a 10 percent rate, all participants' benefits decrease; nevertheless, the share of the project benefits captured by producers and the Alaska and federal government increases to 90 percent, because it is the consumer fuel savings which would be most drawn out over the 25-year life of the project.

| | |
|---|---|
| Consumers | $0.6 billion (mid-1979) |
| Domestic Producer | 2.2 |
| Alaska | 2.9 |
| Federal | 2.2 |
| Pipeline Owners | 0.3 |
| Total NNEB | $8.1 billion |

Other Projections

The participants' shares of net benefits also vary with changes in project costs, gas value, gas flow, or the locus of gas conditioning charges (see Table V-1 and Figure V-1). The producer benefits and, in turn, the Alaska and federal government benefits depend only upon the incremental production costs and the wellhead price of the gas. Consequently, consumers would absorb virtually all of the increased or decreased NNEB caused by variations in the gas value or in the ANGTS construction or other costs. Specifically, consumers benefits rise to $10.1 billion for the case incorporating medium oil price escalation and fall to a negative amount, $-1.9 billion, for the high cost ANGTS case. As might be expected, the benefits for all participants would grow if gas production increased to a level sufficient to flow 3.2 Bcf of Alaskan gas through the ANGTS each day.

Direct Redistribution

Regulation can directly affect the share of the NNEB received by gas producers and the Alaska and federal governments. The proposed FERC rule to include gas conditioning costs in the maximum lawful gas price is an example of such a regulatory action. Instead, if gas conditioning costs were added to the maximum wellhead price, consumer benefits would fall by almost $4.4 billion, under the base case assumptions, to a negative amount (-$1.7 billion).

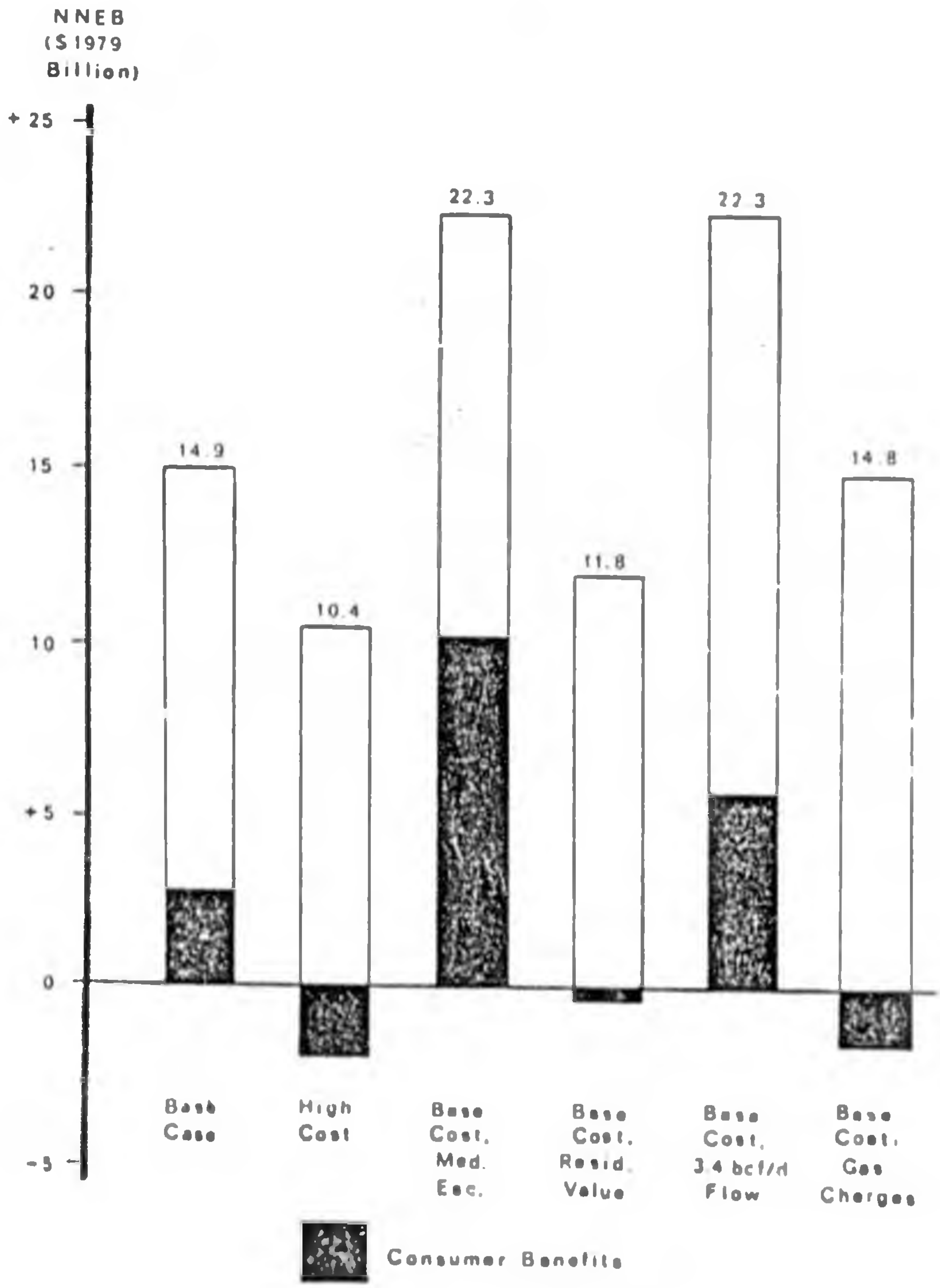
# TABLE V-1

## DISTRIBUTION OF NNEB FOR SELECTED SCENARIOS
(mid-1979 dollars)

| Scenario | Net Benefits | | | | | |
|---|---|---|---|---|---|---|
| | Domestic Producer | Alaska | Federal Gov't. | Consumer | Pipeline Owners | Total NNEB |
| **6 Percent Discount Rate** | | | | | | |
| Base Case | 3.7 | 4.7 | 3.5 | 2.7 | 0.2 | 14.9 |
| High Cost | 3.7 | 4.7 | 3.5 | -1.9 | 0.4 | 10.4 |
| Base Costs, Medium Oil Price Escalation | 3.7 | 4.7 | 3.5 | 10.1 | 0.2 | 22.3 |
| Base Costs, Residual Oil Value, Low Escalation | 3.7 | 4.7 | 3.5 | -0.4 | 0.2 | 11.8 |
| Base Costs, 3.2 Bcf/d Flow | 5.2 | 6.4 | 5.1 | 5.4 | 0.2 | 22.3 |
| Base Case With Gas Conditioning Charges | 5.6 | 5.2 | 5.4 | -1.7 | 0.4 | 14.8 |
| **10 Percent Discount Rate** | | | | | | |
| Base Case | 2.2 | 2.9 | 2.2 | 0.6 | 0.3 | 8.1 |
| High Cost | 2.2 | 2.9 | 2.2 | -2.5 | 0.4 | 5.2 |
| Base Costs, Medium Oil Price Escalation | 2.2 | 2.9 | 2.2 | 4.6 | 0.3 | 12.2 |
| Base Costs, Residual Oil Value, Low Escalation | 2.2 | 2.9 | 2.2 | -1.3 | 0.3 | 6.3 |
| Base Costs, 3.2 Bcf/d Flow | 3.1 | 3.9 | 3.1 | 2.0 | 0.3 | 12.5 |
| Base Case With Gas Conditioning Charges | 3.4 | 3.1 | 3.3 | -2.2 | 0.4 | 8.0 |

FIGURE V-1

ILLUSTRATION OF CONSUMER NNEB SHARES
(6% Discount Rate)




AGO 885960

The countervailing increased share of the NNEB would be captured by the gas producers and the Alaska and federal governments. And because British Petroleum receives a share of the producer surplus through their ownership interest in SOHIO, the total NNEB actually would shrink somewhat.

Other actions which could alter the distribution of the base case NNEB include sharing gas conditioning costs between producers and consumers or lowering the maximum price of Prudhoe Bay gas.[2/] For example, if the lawful price were lowered to the level required to provide the gas producers with a typical industry rate of return on their incremental gas production investment, then the producers and governments' shares of the net benefits would fall to zero. Consumer benefits would grow by a corresponding amount, or $11.9 billion in the base case.

Distribution Among Consumer Classes

This analysis treats "consumers" as one aggregate group; however, not all gas consumers would receive identical shares of the "consumer benefit" discussed earlier. Presently, gas curtailment practices can be interpreted to infer that so-called "firm" gas customers, which already are hooked up to currently flowing gas, have first claim on future gas supplies. Since the costs of new gas supplies are expected to be well above the average cost of old gas now flowing in interstate markets, the purchased gas cost component of today's customers' retail gas prices would be lowest if no new customers what-

2/ Analysis of the legal basis for any of these potential actions is beyond the scope of this analysis.

soever, even high priority ones, were permitted to hook up and if new gas supplies were added only in sufficient amounts to meet existing firm customers' needs.

Wholesale and retail gas prices typically are set by, first, averaging the costs of cheap old gas and expensive new gas on a rolled-in basis and, then, adding an amount to recover fixed and other variable transmission and distribution costs. Consequently, today's gas users of all curtailment priority categories would be worse off if new supplies, added in order to serve new gas customers, increased average unit gas costs by more than larger sales volumes decreased average unit fixed and other costs associated with gas transmission and distribution. This effect, a cross-subsidy of sorts, can occur among members of the same curtailment priority categories (e.g., existing high priority customers and new high priority hookups) or between customer classes with different curtailment priorities. Finally, these cross-subsidies can disadvantage existing customers at the same time that expanding gas supplies and adding new customers, even those of the lowest curtailment priority, can benefit the nation as a whole.

The NGPA permits most of the costs of gas delivered by the ANGTS to be rolled-in. If at any point during its project life delivered Alaskan gas costs were lower or higher than the average costs of all other flowing gas, cross-subsidies of some kind probably would be generated. A meaningful analysis of these effects would require a full general-equilibrium analysis of the entire U.S. energy market, a task well-beyond the scope of this analysis.

Nevertheless, rolled-in pricing and historical embedded cost ratemaking for the ANGTS can generate cross-subsidies within the "consumer" group, and the magnitude of any subsidies and the directions in which they cross between individual consumers can vary over the project's life. Although we did not estimate the magnitude or location of these effects, policymakers may wish to be aware of this potential when formulating an ANGTS regulatory policy.

DISTRIBUTION OF ANGTS OPPORTUNITIES AND RISKS

Previous sections of this analysis have identified numerous uncertainties associated with the ANGTS and with our estimates of the project's expected net national benefits, consumer costs, and shares of the benefits received by various project participants. Each uncertainty embodies an opportunity for better than expected consequences under certain outcomes and a risk of worse than expected results under others.3/

The legislative and legal framework surrounding the ANGTS project, as well as proposed and future federal regulatory actions, will determine the overall size of these "upside" opportunities and "downside" risks and their distribution among Prudhoe Bay gas producers, the Alaska and federal governments, and the project sponsors and their lenders. At this juncture, however, all of the regulatory actions affecting the size and distribution of the opportunities and risks are not fully defined and in place. Since the character of the actions are a major focus of current FERC work, they are discussed briefly here in order to connect them to the main thrust of our analysis (estimating the pipeline cost of service and the level and distribution of the NNEB).

3/ For purposes of this discussion, uncertainty refers to the probability of an outcome or event. We label the consequences associated with any one outcome an opportunity if they would increase the welfare of the nation as a whole or of a particular participant compared to the base case; conversely, we label adverse consequences as risks.

The legal and institutional arrangements surrounding the ANGTS appear to be taking a shape somewhat distinct from typical gas pipeline practices, perhaps a necessity for a project of the sheer size of the ANGTS and accompanied by its unique market, technological and regulatory uncertainties.[4/] In order to provide context for this discussion, we assume the following arrangements:

- At the wellhead, gas producers would receive the NGPA maximum lawful price but must absorb the full costs of gas conditioning;
- The project sponsors would confine their role to strictly providing transportation service. Lower-48 gas transmission companies and/or gas distribution utilities would purchase the Alaskan gas directly from Prudhoe Bay producers under long-term contracts with take-or-pay provisions.
- And where other gas distribution utilities would purchase Alaskan gas at the citygate, the purchase price plus ANGTS cost of service would be "rolled-in" with the transmission company's other sources of gas. These gas utilities also would purchase this gas on a take or pay basis. Direct-purchase utilities, as well as those purchasing at the citygate, would roll-in all of their purchased gas costs for sale at retail.

Although details of this description may not be fully correct, we believe for purposes of this analysis that it presents a sufficiently accurate picture of the kinds of arrangements ultimately likely to exist. If so, these kinds of conditions have important implications for the distribution of the ANGTS opportunities and risks.

4/ For an excellent discussion of this aspect of the ANGTS, see Arlon R. Tussing and Connie C. Barlow, Financing the Alaska Highway Gas Pipeline: What Is To Be Done? prepared for the Alaska Legislative Affairs Agency, Juneau, Alaska, April 1979.

In this context, the balance of this discussion evaluates the distribu of the ANGTS opportunities and risks under three kinds of outcomes: i) bet or worse cost experience at the gas production level of the overall project ii) better or worse experience in the portions of the project which may control the marketability of Alaskan gas and, iii) once constructed, catastroph failure to make the project operational, a possibility which may determine th financiability of the ANGTS. Across all three kinds of outcomes, however, it is important to note that the ability to market ANGTS gas and to finance the project are closely related.

CHANGED GAS PRODUCTION EXPERIENCE

Compared to the base case, gas production experience upstream from the ANGTS could prove in actual practice to be better or worse than expected, for three reasons. The incremental costs of the gas conditioning facility could underrun or overrun our base case estimate. Similarly, in order to maintain the level of crude oil recovery while selling gas from the Sadlerochit pool of the Prudhoe Bay field, more or less costly water-flooding might be required. Finally, even with substantial water-flooding, a large loss of crude oil recovery might occur.[5/]

The base case, as noted above, assumes that producers would condition the gas and would be paid the maximum wellhead price specified by the NGPA. Under these circumstances, more favorable production experience would increase the ANGTS project's NNEB over base case levels. The increase would be shared

5/ Although not considered in this analysis, one recent estimate is alledged to envisioned a catastrophic loss of 1.5 to 2.0 billion barrels of ultimate crude oil recovery.

among gas producers and the Alaska and federal government in their relative proportions shown under the base case. All other participants would be unaffected.

Conversely, a worse production experience would have the opposite effect. Up to the point where gas producers' "normal" profits begin to erode, the full effect would fall on these same three project participants. Beyond that point, these three participants could incur real resource costs greater than their revenues. And if incremental production costs ever exceeded incremental revenues, production would cease unless the wellhead price were altered, an action which would need to be evaluate in light of the overall project's economic merits at that point.

At the production level, then, the assumed institutional arrangements may allocate a large share of the NNEB to producers and governments. But their upside opportunities would depend upon their skill and luck in building the gas conditioning facilities and in developing the Prudhoe Bay gas field. Unless the experience worsened by an extreme amount, other participants would not feel an effect or face a decision problem.

The third outcome, an irreversible and substantial loss of crude oil recovery through Sadlerochit gas sales, is especially difficult to evaluate without a detailed reservoir simulation of production alternatives from the reservoir and a full, general-equilibrium analysis of the overall U.S. energy market. Importantly, however, trading the increased NNEB made available from the use of Prudhoe Bay gas from the ANGTS project for an equal or lesser decrease in NNEB from reduced Prudhoe oil recovery would not necessarily be imprudent. Undoubtedly, however, the distribution of national welfare would be altered by trading increased gas production for decreased oil production, quite possibly to the disadvantage of the oil/gas producers and the Alaska and federal government.[6/]

CHANGED MARKET PROSPECTS

Once the project is certified and the pipeline is built and put into service, federal regulation will work to compel the ANGTS gas to enter the U.S. energy market, in the physical sense of molecules of Alaskan gas finding their way to the burner tip. But in an economic sense, changes from the base case could alter the market prospects of the project.[7/]

Four kinds of events could alter the base case market attractivenss of Alaskan gas. Two of these could be caused by changing either the value of the gas or its delivered cost. Because of changed fuel availabilities, Alaskan gas might displace a fuel other than distillate oil; conversely, changed world oil prices might alter the value of Alaskan gas as a substitute for distillate. Alternatively, the gas value could remain unchanged but its delivered costs could be higher or lower due to the ANGTS construction cost experience or Canadian actions, as discussed earlier in Section IV.

The other two causes of altered market prospects for Alaskan gas are more analytically complicated. On the optimistic side, extra gas reserves, on the North Slope or along the length of line, could facilitate a higher rate of gas flow through the system. And on the more pessimistic side, a cheaper source

6/ This analysis also was beyond the scope of this work.

7/ In the base case, it bears repeating that the opposite paradox may exist; that is, the project may make economic sense but encounter difficulties in the marketplace caused by traditional tariff practices.

of gas (measured in real resource cost terms) might become available after a firm and irreversible commitment was made to the ANGTS project. If this more economical source could not find a place in the market in the face of enforced marketability of ANGTS gas, Alaskan gas would, in effect, displace a cheaper source of gas rather than distillate fuel or another more expensive energy form.

All four kinds of these events would increase or decrease the ANGTS project's net economic benefits to the nation as a whole. As noted by our earlier sensitivity analysis, however, the effects would need to be of enormous proportions, relative to the base case assumptions, in order to negate all of the NNEB (see Section II).

With relatively minor exceptions, consumers would receive the full measure of this increased or decreased NNEB. Enforced marketability—applied through institutional arrangements, such as permitting ANGTS project sponsors to act strictly as providers of a transportation service; legal arrangements such as gas purchase contracts of a take-or-pay variety; and regulatory practices, such as rolled-in pricing—would shift almost all of the upside opportunities and downside risks associated with these four kinds of events to gas consumers.

Incentive Rate of Return

One exception to this pattern of opportunities and risks centers on the incentive rate of return (IROR) mechanism planned to be imposed on the project sponsors. The IROR would shift some of the opportunity and risk associated with construction cost uncertainties to the sponsors. By this reallocation, it is hoped that the IROR would reduce the probability of large construction cost overruns. As currently envisioned, the IROR would lower the overall rate of return on the ANGTS consortium's equity investment if certain project c[osts] were to grow more than 30 percent over base estimates and would raise the r[ate] of return if actual costs prove to be less than estimated.

The effectiveness of an IROR scheme in discouraging cost overruns is not well understood. Reviews of similar incentive contracting by the Air Force have been inconclusive.8/ Moreover, some believe that the TAPS project had greater incentives to avoid cost overruns because the revenues received by th[e] oil companies were reduced dollar-for-dollar by "any and all cost overruns." Yet Mead estimates that Alyeska's costs increased by 23 percent annually after adjusting for inflation and changes in scope.9/

For the high construction cost case the imposition of the IROR penalty would only lower the annuity-equivalent cost of service by 8 percent relative to the cost of service for the same construction cost scenario without the IROR penalty.10/ Thus, although the IROR mechanism would shift risks in a direction that should make those responsible for ANGTS more concerned about cost control, the incentives appear less strong than those asserted to have existed for the TAPS project.

---

8/ For instance see Robert Perry, et. al., System Acquisition Strategies, The Rand Corporation, R-733-PR/ARPA, June 1971; Frederic Scherer, The Weapons Acquisition Process: Economic Incentives, Harvard, 1964; and Robert Summers, Cost Estimates as Predictors of Actual Weapon Costs, The Rand Corporation, RM-3061-PR, March 1965.

9/ [illegible] Mead, Transporting Natural Gas from the Arctic, pp. 88-89.

10/ This may overstate the effect of the IROR penalty because the existence of the "greater risks" from the IROR plan caused a higher base rate of return.

AGO 885969

Increased Gas Flow

A second exception to exclusive consumer susceptibility to changed market prospects centers on the effect of an increased flow rate. In addition to the extra NNEB shown for this situation 11/ producers of the extra gas required to support a higher flow rate also might obtain some further national economic benefits. The size of the total NNEB effect, however, would depend on wellhead pricing, the real resource costs of the extra production, and the national domocile of the firm owning the gas reserves.

Displacement of Cheaper Gas

The fourth situation, under which Alaskan gas would drive out a cheaper gas source, is included here simply to round out our presentation. At this juncture, we are not aware of any gas source which might be driven out by Alaskan gas and which might cost less to the U.S. in real resource terms. Clearly, this hypothetical event would reduce the NNEB. But until a specific alternative source could be identified and its real resource costs and delivered costs evaluated, the likelihood of this phenomenon and its effects on the magnitude and incidence of the NNEB are unclear.

Rolled-In Pricing

A final point concerning the distribution of risks and opportunities related to marketability of Alaskan gas concerns "rolled-in" pricing. The NGPA included an incremental pricing provision for high cost gas. This mechanism allocates a share of transmission companies' gas acquisition costs (generally those in excess of the pre-1977 ceiling price for new interstate

11/ Refer to the base costs, 3.2 Bcf/d flow scenarios of Table V-1.

natural gas) to a segregated account for passthrough to low priority users. This passthrough continues until their retail gas prices reach the level of a substitute fuel (distillate or, subject to certain findings, residual fuel oil).12/ And over time as, first, all low-priority customers reach the substitute fuel price level and, then, all customers' gas prices reach that level, a situation akin to the longstanding tradition of rolled-in gas pricing once again will prevail in lower-48 retail gas markets.

In Section 208, however, the NGPA treats the Alaskan gas pipeline project in a manner consistent with traditional gas pricing. From the outset of its operations in 1984, the project's transportation costs and most of its gas acquisition costs would be rolled-in.

Rolled-in pricing of Alaskan may, in part, be necessary in order to ensure the marketability of Alaskan gas in the face of traditional methods of setting gas pipeline tariffs. Earlier, Figure IV-1 illustrated that delivered costs of Alaskan gas would initially be much higher than the "levelized" annuity-equivalent of these costs as well as the price of distillate fuel. Unless government or another institution intervenes as a financial intermediary to transform the upside-down tariffs into, say, a levelized cost, another mechanism must lower the apparent delivered costs of gas Alaskan gas during its early years. Rolled-in pricing is one such mechanism; consequently, it can help ameliorate any marketability problems caused by applying traditional pipeline ratemaking to gas delivered from Alaska.

12/ NGPA, Title II.

Importantly, the success of rolled-in pricing for this purpose depends upon the availability of cheaper old gas; unfortunately, the availability of cheaper gas is not fully guaranteed. Moreover, if cheaper gas were available, the extent to which the market problems of Alaskan gas are redressed by rolled-in pricing may not be as large as might at first appear.

Table V-3 presents illustrative U.S. average gas prices, with and without Alaskan gas, for 1985, 1990, and 1995. For the highest cost year (1985), the rolled-in cost of Alaskan gas would be $1.22 per million Btu lower than the cost associated with a separate rate schedule and traditional pipeline tariffs. This 1985 rolled-in cost, however, would be only $0.39 per million Btu below the "levelized" cost of Alaskan gas. By 1990, the Alaskan supplies would approximate average costs without Alaskan supplies, and the average price would exceed the levelized cost of Alaskan gas. Finally, on an annuity-equivalent basis, the delivery of Alaskan gas might decrease overall costs of gas for the 1984 to 2008 period.

To sum up, primarily gas consumers would be exposed to the upside opportunities and downside risks associated with the market attractiveness of Alaskan gas. But compared to gas producers who face the prospect of changed gas production experience, (along with the Alaska and federal governments) consumers' final outcome will be controlled to a much greater extent by remote events (world oil prices) and other project participants' skill and luck (the constructors of the ANGTS). Also, our sensitivity analysis indicates that the range of consequences, measured up and down with respect to their estimated share of the base case NNEB, is much wider for consumers, in both dollar and

## TABLE V-2

### ILLUSTRATIVE EFFECTS OF ALASKAN GAS DELIVERIES ON AVERAGE CITYGATE GAS PRICES (mid-1979 $ per mmBtu)

| Year | Average Gas Price Without Alaskan Gas[a/] | Alaskan Gas Cost With Utility Method | Average Gas Price With Alaskan Gas[b/] | Change In Average Gas Price |
|---|---|---|---|---|
| 1985 | 2.73 | 4.01 | 2.79 | +0.6 |
| 1990 | 3.24 | 3.30 | 3.24 | +0.00 |
| 1995 | 4.01 | 2.83 | 3.95 | -0.06 |
| "Levelized" Price[c/] (1984-2008) | 3.76 | 3.18 | 3.73 | -0.03 |

a/ Source: Energy Information Administration, Administrator's Annual Report, 1979, Series C.

b/ Assumes that Alaskan gas provides 5 percent of the gas supplies at the illustrative citygate.

c/ 25-year annuity-equivalent price, calculated using a 6 percent discount rate.

percentage terms, than for other participants (see Figure V-1). Unfortunately, the basis for assigning sensible probabilities to the variables which drive this range of outcomes, especially world oil prices and ANGTS construction costs, is weak.

CATASTROPHIC FAILURE TO OPERATE

Catastrophic failure alludes to the intervention of some event which interferes with operation of the ANGTS after some or all of its construction costs have been incurred. This interference could permanently prevent operation or, alternatively, could delay operation for a period of sufficient length to financially bankrupt the project sponsors in the face of large annual debt service requirements associated with the project's debt-laden capital structure.

If neither an "all events" tariff nor a loan guarantee is provided to the project, catastrophic failure to operate would create an opportunity loss to certain project participants and an actual net loss of NNEB for the nation as well as for certain other participants. Compared to the base case, consumers would face an opportunity loss whose magnitude would be bounded by the gas value, less the estimated delivered costs of gas. But to the extent that Prudhoe Bay gas later would become available for their use, this opportunity loss would be reduced. Similarly, gas producers and the Alaska and federal government would face some loss in an opportunity sense.

The tangible NNEB loss, however, would consist mainly of the real resources expended to build an inoperable pipeline. And this loss would fall on the project's investors. First, the ANGTS project's equity investors would lose an amount limited either by their legal liability or by their capacity to pay. Then, its lenders would absorb the balance of the loss. Because the magnitude of the project is large compared to the equity-base of its sponsors and because 75 percent of the financing is expected to be in the form of debt, it is likely the bulk of the loss associated with a catastrophic failure to operate ultimately would impinge on the project's lenders.

IMPLICATIONS FOR FINANCING THE ANGTS

Financing problems alledged to be faced by the ANGTS may be rooted, in the most fundamental sense, in a lack of symmetry in opportunities and risks faced by project investors. This lack, in turn, stems from the size of the project; its technical, marketing, and regulatory uncertainties; and the high degree of leverage (or high fraction of debt financing) typically expected in a public utility venture. Compare the circumstances of the pipeline investors and the other participants:

- For any of the outcomes short of the catastrophic failure to operate, utility regulation would fix the rewards of the project sponsors and lenders to a "normal" return, adjusted only by the IROR mechanism instituted to stimulate construction cost control. Compared to the target (or center) rate of return, the full range of cost outcomes can swing the overall weighted average return to equity investors by approximately 2.5 percent upward (for filed costs) or 2.5 percent downward (for high costs) from the base case rate of 17.0 percent.[13/] Better or worse gas production experience or better or worse market attractiveness may improve the investors' confidence of receiving a "normal" return, but otherwise their "upside" opportunities and, importantly, their "downside" risks are constrained as long as the project is certified

13/ To a limited extent, the investment tax credit realized by the pipeline owners for actual capital expenditures could counteract the incentives sought through the IROR. We presume that FERC's IROR order will successfully negate any perverse incentives introduced by the ITC.

and it commences operation approximately on schedule. This, of course, is the tradition of public utility regulation in the U.S. And this tradition, in part, explains the large degree of financial leverage that regulated utilities typically achieve in their capital structures.

- Under a catastrophic failure to operate, however, investors may be faced with a real possibility of ruin. Consequently, the project holds out the prospect to investors of a catastrophic downside risk of unknown likelihood, a minor share of the NNEB in the best of circumstances (i.e., a tax credit benefit), and minor upside potential associated with the IROR mechanism.

These observations, if accurate, may explain why investors, particularly lenders, might seek insurance against a catastrophic event in the form of an "all events" tariff or a loan guarantee.

# VI. FINDINGS AND CONCLUSIONS

This analysis has found that the proposed Alaskan gas pipeline project is likely to provide significant economic benefits to the nation. The expected net national economic benefit to the United States is estimated at $14.9 billion (mid-1979 dollars). Of course, the actual benefit will remain uncertain until the assumptions underlying the NNEB estimate are proven by time. For example, the NNEB could decrease to about $11 billion if the worst case cost overruns were to occur or if Alaskan gas were required to compete in lower-48 fuel markets with residual rather than distillate fuel oil. Alternatively, the NNEB could grow to $22.3 billion if the distillate price were to escalate at a medium, rather than a low, rate. On balance, however, the NNEB should remain positive over a wide range of future events. And this robustness of the NNEB supports a conclusion that the proposed ANGTS project would be in the nation's economic interest.

But within the larger context of net benefit to the nation as a whole, a second important measure of the desirability of the Alaskan gas pipeline project concerns the cost of the gas to customers in the lower-48. The analysis has found that the traditional regulatory approach for establishing the cost of service for gas transportation (and other institutional factors associated with gas regulation) has important implications for the desirability of Alaskan gas to consumers and, in turn, for its marketability.

Because traditional ratemaking methods would create time patterns for the delivered cost of Alaska gas which would be upside-down compared to those of competing fuels, this analysis adopted an annuity-equivalent measure of the cost to consumers. On an annuity-equivalent basis, energy consumers would have a clear preference for Alaskan gas compared to distillate fuel oil. Further, this preference would persist even if Alaskan gas were used in the lower-48 as a substitute for cheaper fuels such as residual fuel.

Early-on in the project's life, however, traditional cost of service ratemaking would confront customers with an actual gas cost well above its annuity-equivalent cost. Later on, this ratemaking approach would make the actual delivered cost well-below the annuity-equivalent. As a result, purchasers offered a separate rate schedule for Alaskan gas would find the gas unattractive compared to distillate fuel in the project's early years. But taking the case of an industrial user offered a long-term contract under a separate rate schedule, priorities assigned industrial gas users during previous curtailments make it unlikely that such a user would have faith, say, in a long term Alaskan gas purchase contract.

Thus, this analysis found that _if_ Alaskan gas were sold on a separate schedule, it could encounter serious short run marketability problems. These problems would arise from the regulatory method used to price the gas rather than from its underlying economic merits. In turn, _if_ marketability of Alaskan gas were uncertain, then the ANGTS project sponsors would probably not succeed in arranging financing for the project.

These short-run concerns about the marketability and financing of the ANGTS project stem from one aspect of traditional ratemaking. But consistent with another feature of traditional gas ratemaking in the U.S., the NGPA exempts gas transported through the ANGTS from the transitional incremental pricing provisions also contained in the Act. These conditions would allow essentially all of the costs associated with acquiring and transporting Alaskan natural gas to be averaged with gas transmission companies' and gas distribution utilities' other supplies of lower cost gas, if available. This analysis found that, although this rolled-in pricing policy may appear to be a major subsidy to the ANGTS project, Alaskan gas actually could lower the annuity-equivalent average price of the total U.S. natural gas supply over the next 25 years. Thus, rolled-in pricing would ameliorate the market obstacles initially facing the sale of Alaskan gas without the risk of proping up a fundamentally, economically unsound source of gas supply.

This conclusion—that the Alaskan gas project should be in the interests of both the nation and the nation's gas consumers—is valid if the ANGTS were constructed at a cost in line with current estimates. Consumers, however, could lose $2.2 billion if construction problems lead to the high cost case for the pipeline construction. Gas producers, the Alaskan and federal governments, and the pipeline owners still would benefit by more than $10 billion.

In addition to consumer benefits, analysis of the distribution of the NNEB from this project shows that the Prudhoe Bay gas producers benefit substantially in all cases. Surprisingly, however, even producers are not the major beneficiaries. Instead, the Alaskan state government and the federal government together are expected to obtain extra tax revenues well in excess of the benefits captured by consumers and producers. In turn, these extra taxes would benefit all taxpayers, in the state and across the United States, in the form of otherwise reduced taxes.

The marketability of Alaskan gas, even given the rolled-in pricing provision of the NGPA is not without its uncertainty. Currently, any risks and opportunities associated with the market prospects of Alaskan gas appear as though they will be borne mainly by consumers. Market prospects for the gas, and the risk and opportunity position of consumers, could be altered dramatically by actions which would allocate a larger share of the net national economic benefits to gas users. A FERC proposed rule, which would require producers to pay gas conditioning costs, is assumed in this analysis to be implemented. This rule would allocate to consumers what otherwise would be even larger producer, Alaskan and federal shares of the NNEB. In addition, it should better insure the marketability of Alaskan gas and, in turn, the ANGTS consortium's ability to arrange project financing.

Any remaining marketability and financing problems will arise because of other important project uncertainties; for example, the risk of an enormous cost overrun or a catastrophic failure, arising from some yet unknown source, ultimately to make the project fully operational. Private lenders, who are expected to provide 75 percent of the required funds, are appropriately conservative. As a requirement for providing the large amount of debt to a single project f the ANGTS magnitude (requiring more than $10 billion of debt if built at estimated costs), lenders claim to need ironclad guarantees of repayment of all loans and interest in "all events", including project abandonment.

The NNEB estimates indicate that FERC should encourage the project's implementation in the interest of national economic efficiency; however, the problems of devising an equitable way to promote implementation remain, especially in the area of project financing. For example, an "all events" tariff could provide repayment assurance to lenders. The tariff, however, would shift almost all of the risk associated with catastrophic cost or technical problems to consumers of Alaskan gas. Since these consumers—especially in contrast to the general taxpayers of Alaska and of the entire U.S.—are not expected to be the major beneficiaries of the project under base case conditions, it may be appropriate to consider whether they alone should assume the full burden of these risks, however slight their likelihood of occurence. Importantly, the same line of reasoning may apply equally to the project's investors.

With one exception, there appear to be few feasible and desirable alternatives to consumer assumption of opportunities and risks associated with delivered gas value or cost. The one exception is that some of the risks of cost overruns may be allocated to the project sponsors through an incentive rate of return mechanism. Although an incentive rate of return tariff is certainly preferable to the traditional full cost of service tariff, its potential efficacy is uncertain.

Thus, there are important benefits to be reaped from proceeding with the Alaskan gas pipeline system, but there are also significant regulatory problems to be resolved to develop an equitable allocation of project costs and benefits that maintains consumer and investor interest in implementation of the proposed system.