FERC -
REVIEW OF AK
NATURAL GAS
TRANS. SYSTEM

A REVIEW OF ALASKA NATURAL GAS TRANSPORTATION SYSTEM ISSUES

Submitted to the
Federal Energy Regulatory Commission
Under Contract No. EJ-78-C-01-6395

May, 1979

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EXECUTIVE SUMMARY

This report addresses several major questions that relate to the Federal Energy Regulatory Commission's (FERC) deliberations concerning the proposed Alaska Natural Gas Transportation System (ANGTS):

- In light of recent changes in gas supply markets, are there still net benefits to the nation from proceeding with the proposed Alaskan gas pipeline project?
- If the potential benefits remain significant, why must low cost old gas subsidize the project through rolled-in pricing of Alaskan gas and why may special regulatory treatment, such as an "all events tariff" to insure debt repayment, be necessary?
- How does the planned implementation of ANGTS affect other potential gas supply opportunities, especially Mexican gas purchases?
- What policy options, such as gas conditioning charges and wellhead price ceiling levels, exist for reallocation of project costs, and how would these options affect the distribution of the project's opportunities and risks?

The analysis presented here concludes that the ANGTS project should provide significant economic benefits to the nation; nevertheless, serious obstacles to project implementation remain. At least one of these problems, the high initial cost of delivered natural gas, results from the traditional embedded historical cost method of ratemaking for gas regulation. The negative effects that this regulatory approach creates for the marketability of Alaskan gas can be counter-balanced to a large extent through another traditional practice of natural gas regulation, average cost pricing. Other problems revolve largely around questions of the equitable distribution of project benefits and costs. Questions about how to allocate the opportunities and risks associated with the project's significant market, technological, and regulatory uncertainties present especially thorny problems.

Since these latter issues can only be resolved by policymakers' applying their judgment about what is equitable, this analysis can come to no conclusions about the appropriate path for policymakers to take. Instead, it seeks to analyze the extent to which the project could benefit the nation as a whole and specific parties such as gas producers or consumers under a variety of possible scenarios and policy decisions. This information should assist federal policymakers in weighing the significance of the policy questions concerning the ANGTS that they will face.

NET NATIONAL ECONOMIC BENEFIT

The Net National Economic Benefit (NNEB) measures the extent to which the value to the nation of Alaskan gas, delivered to energy users, exceeds the real resource costs to the nation of producing and transporting the gas. For this analysis:

NNEB = Delivered Gas Value
- Production Costs
- Transportation Costs
- Foreign Producer Benefits.

Briefly, these components are estimated in present value-equivalent terms and have the following definitions:[1/]

1/ See Section II of this report for an expanded discussion of the NNEB components and of the reasons for using a 6 percent after-tax real discount rate in calculating the present values.

Delivered gas value: the real resource costs to the nation of the alternative energy source likely to be used in the absence of Alaskan Prudhoe Bay gas.

Production costs: the incremental real resource costs incurred to produce the Prudhoe Bay gas,[2/] including capital expenditures, income taxes on required revenues, *ad valorem* taxes, and operation and maintenance (O&M) expenditures, but excluding costs deemed for purposes of this analysis to be transfer payments within the U.S. economy (royalties and severance taxes).

Transportation costs: the incremental real resource costs incurred to move gas from Prudhoe Bay to the citygate in the lower-48 states, including capital expenditures, income taxes, *ad valorem* taxes, O&M expenditures for U.S. segments of the ANGTS, and U.S. cost of service payments to Canada for pipeline segments within its territory.

Foreign producer benefits: the share of the potential net national project benefits, in the form of payments to gas producers in excess of the real resource costs of production, which escapes the U.S. economy because a foreign firm owns a portion of the Prudhoe Bay gas.

The base case used for this analysis resembles the ANGTS scenario used for the NNEB discussion in the *President's Decision*.[3/] In order to be consistent with the earlier discussion on this one point, the base case assumes a gas value equal to the wholesale price of distillate fuel. But in contrast to the *President's Decision*, the base case envisions more rapid world oil price escalation over time and applies a 6 percent real after-tax discount rate to account for consumers' time preferences.

2/ Incremental costs are costs in addition to any expenditures that would have been required in any case to produce oil at Prudhoe Bay.

3/ Executive Office of the President, *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, Washington, D.C., September 1977. This is the set of assumptions leading to the results presented on pp. 93-98 of the *President's Decision*.

Under these base case assumptions, the NNEB and its components are estimated to be:

	(mid-1979 dollars)
Delivered Gas Value	$ 33.3 billion
- Production Costs	- 6.0
- Transportation Costs	-11.9
- Foreign Producer Benefits	- 0.5
NNEB	$ 14.9 billion[4/]

A high degree of uncertainty is associated with the base case NNEB estimate. Distillate fuel prices may differ from the assumed levels or Alaskan gas may not displace distillate because of changed project costs or altered availability of other fuels. The distillate price assumptions used for the base case, however, may be conservative; actual future oil price experience, we believe, would be more likely to increase the NNEB estimate than to decrease it. Moreover, worst case cost growth, as estimated by the Departments of the Interior and Transportation (in which the construction costs for both the Alaskan and Canadian segments would more than double over filed estimates), would reduce the NNEB to $10.4 billion (mid-1979 dollars), still a significant level.[5/] Finally, if fuel availability were to reduce the gas value to the price of residual fuel oil instead of distillate, the NNEB also

4/ Section II describes the discounting methodology. The President's Decision estimated the NNEB at $5.8 billion (1975 dollars). The major differences are the Decision's assumption of a constant future price (in real terms) for distillate oil and its use of a 10 percent real discount rate.

5/ U.S. Department of the Interior and U.S. Department of Transportation, Alaska Natural Gas Transportation Systems: White House Task Force Lead Agency Report on Construction Delay and Cost Overruns, July 1, 1977.

would remain significantly positive, $11.8 billion (mid-1979 dollars).

Across all reasonable scenarios, the ANGTS project appears to be economically efficient from a national perspective, in terms of reduced real resource costs for comparable amounts of energy use. But the project may not always provide economic benefits from the narrower perspective of gas consumers. The actual delivered cost of Alaskan gas to consumers compared to their alternative fuel choice—not simply the real resource costs incurred to produce and deliver it—determines the share, if any, of the national benefits accruing to gas consumers.

DELIVERED GAS COST

The delivered cost of Alaskan gas not only provides a necessary input to calculating the share of the NNEB captured by consumers but also provides important insights into problems that Alaskan gas could face in the energy marketplace. And since the success of the ANGTS as a private venture depends upon the marketability of the gas, the delivered costs of Alaskan gas also illuminate problems with obtaining private financing for the project.

The citygate cost of delivered Alaskan gas has four components: the price paid to producers for the gas at the wellhead, Alaskan state severance taxes imposed on gas production, any additional charges for conditioning the gas prior to introduction into the ANGTS, and the "cost of service" allowed to be charged by the project sponsors for transporting the gas from Prudhoe Bay to its markets. For the base case assumptions used in the NNEB analysis, the annuity-equivalent cost of delivered gas (in 1979 dollars) is estimated as follows:

Component	25-Year Annuity-Equivalent Cost[6/] (mid-1979 dollars)
Wellhead Gas Price	$1.68 per million Btu
Severance Taxes	0.17
Gas Conditioning Charges	0.00[7/]
Pipeline Cost of Service	1.33
Delivered Cost of Gas	$3.18 per million Btu

The delivered cost of gas hinges importantly on all four of its components. Because of this shared importance, focusing on one particular aspect of the delivered cost--typically potential ANGTS cost overruns and resulting pipeline cost of service increases--can ignore other important cost items. The price producers are allowed to charge, the taxes the state and federal governments are allowed to levy, and the locus of the gas conditioning charges all make important contributions to the cost consumers would pay for Alaskan gas.

Transportation costs (i.e., the pipeline cost of service associated with the ANGTS project) account for less than half of the citygate cost of the gas. In percentage terms, major changes in transportation assumptions do not

6/ The calculation of annuity-equivalents is described in Section III of this report. Briefly, it is a levelized unit cost which represents the constant unit amount that would yield a present value equal to the present value of the unit costs resulting from traditional gas ratemaking. This approach, we believe, represents an improvement over the arithmetic average approach used in the President's Decision because it incorporates a measure of consumers' time preference in a manner consistent with life-cycle cost decisionmaking.

7/ This zero gas conditioning charge is based on FERC's proposal for gas producers to pay gas conditioning costs. The imposition of gas conditioning charges would raise the delivered gas cost to $3.88 per million Btu. This issue is examined in the body of the report.

alter the citygate cost significantly. For example, the annuity-equivalent delivered cost would vary by less than 10 percent for any of the following events: a doubling of construction costs on the high risk segment of the ANGTS located in the harsh Alaskan environment,[8/] a doubling of Canadian segment construction costs, or a doubling of the gas flow rate assumed in the base case. For the worst case cost overrun scenario, the delivered cost estimate would be $3.55 per million Btu, 12 percent above the base case.

The traditional approach to ratemaking for gas pipeline tariffs—the so-called historical embedded cost method—would generate larger swings in the cost of gas from year to year than the annuity-equivalent cost changes resulting from any of the events mentioned in the previous paragraph. Because the historical embedded cost method of setting gas rates provides a constant rate of return on the remaining book value of the pipeline's initial capital investment, payments to provide the return to the pipeline and, in turn, the gas cost to pipeline customers would be highest in the first year of pipeline operation.

Thereafter, along with the remaining book value of the pipeline, the delivered gas cost would decline annually in real terms until the rate base is entirely depreciated (after 25 years of operation for the ANGTS). Afterward the pipeline would receive no further return on rate base, and delivered gas costs would consist only of the purchase costs of the gas at the wellhead plus pipeline O&M costs and other annual expenses, such as taxes. For example, the

8/ Compared to filed estimates.

following table illustrates the base case delivered costs over time (annuity-equivalent cost = $3.18 per million Btu):

	Delivered Gas Cost (mid-1979 dollars)
Year 1	$4.18 per million Btu
Year 10	2.98
Year 25	2.28

ALASKAN GAS VERSUS OTHER ENERGY ALTERNATIVES

The ANGTS project is expected to provide advantages to the nation and to consumers over alternative fuels. Under the base case assumptions:

- the annuity-equivalent price of Alaskan gas would be 12 percent below the assumed annuity-equivalent price for distillate fuel oil;
- over a 25-year project lifecycle, gas users could save $2.5 billion (mid-1979 dollars) with Alaskan gas compared to distillate fuel oil and $13.2 billion compared to Mexican natural gas keyed to distillate oil prices;
- the delivered price of Alaskan gas would be higher than the price of distillate at the citygate for the first seven years of the project based on historical embedded cost ratemaking, in spite of net benefits to consumers and the nation as a whole. For this and all other cases, high gas costs for the earliest project years result from the application of traditional ratemaking to the ANGTS. And these high initial rates would exacerbate the uncertainty associated with Alaskan gas marketability and with the financing of the project.

This analysis of the economic attractiveness to energy users under base case conditions indicates that, on a 25 year annuity-equivalent basis, Alaskan gas would be less expensive than distillate fuel oil, Mexican gas, or even residual fuel oil.[9/] Thus, if it can be constructed at expected costs, the project would be in the national interest for any reasonable energy supply projections.

For the high cost case, the ANGTS project could benefit the nation if it substituted for residual fuel oil, but consumers might chose residual over the Alaskan gas. In fact, consumers would perceive a less than 2 percent annuity-equivalent price advantage from Alaskan gas compared to distillate fuel oil. The differences between the conclusions about the economic attractiveness of the proposed ANGTS project for gas users and for the nation result from the fact that participants other than consumers receive shares of the NNEB. This issue is addressed in Section V of the analysis.

The most important issue related to the market prospects for Alaskan gas is that the time-profile of delivered costs resulting from traditional cost of service ratemaking could create initial marketing difficulties for Alaskan gas, even when its lifecycle cost to consumers is lower than alternative fuels. As noted earlier, an historical embedded cost of service consists of annual operating expenditures plus a return on the book value, after depreciation, of the rate base. Since the rate base is highest in the project's earliest years, the cost of service is highest then as well. In turn, the

9/ These annuity-equivalents do not account explicitly for any atypical risks consumers might bear for the ANGTS project. And although Alaskan gas appears superior to Mexican gas on an annuity-equivalent cost basis, this does not mean that Mexican gas should not be imported. Policymakers must judge potential Mexican imports on their own merits compared to the alternative fuel that these imports might displace and any other relevant considerations.

initial delivered costs of Alaskan gas exceed the expected prices of alternative fuels. Consequently, the method of pipeline regulation can make Alaskan gas appear unattractive to potential customers early-on, even though the annuity-equivalent delivered cost would favor Alaskan gas from the outset (see Figure S-1).

DISTRIBUTIONAL ISSUES AND SPECIAL REGULATORY TREATMENT

The regulatory policy applied to the overall Alaskan gas project also can affect the recipients of the project's net economic benefits. This analysis examines the allocation of the net economic benefits, shown earlier, among gas consumers, the producers of Prudhoe Bay gas, the state of Alaska, the federal government, and gas pipelines. Under the base case assumptions, the NNEB would be captured as follows:

Consumers (fuel cost savings)	$ 2.7 billion (mid-1979)
Domestic Producers (extra profits)	3.7
Alaska (extra taxes and royalties)	4.7
Federal (extra taxes)	3.5
Pipelines (tax credit)	0.2
NNEB	$14.9 billion

These shares of the NNEB are illustrated in Figure S-2.

Very briefly, consumer benefits are the savings from purchasing Alaskan gas compared to alternatives. Domestic producer benefits are the profits after taxes that they receive over the minimum profits necessary to attract the producers to sell gas. Alaskan benefits measure the difference between actual tax and other revenues received by the state from the project and necessary state expenditures resulting from the project. Federal benefits are the federal income taxes levied on the gas producers' extra before tax pro-

FIGURE S-1

ALASKAN GAS AND THE BASE CASE ALTERNATIVE FUEL PRICE PROJECTIONS

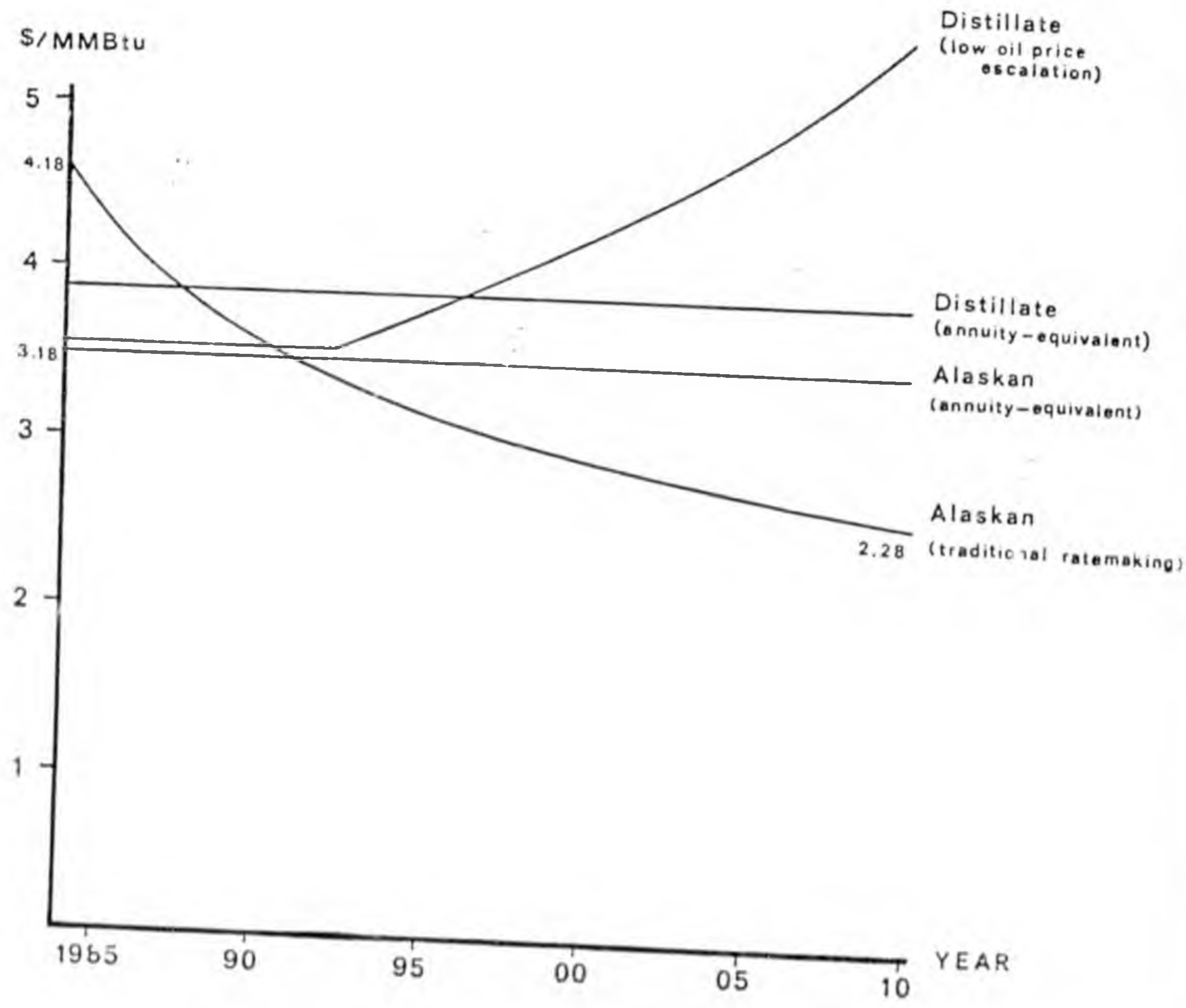

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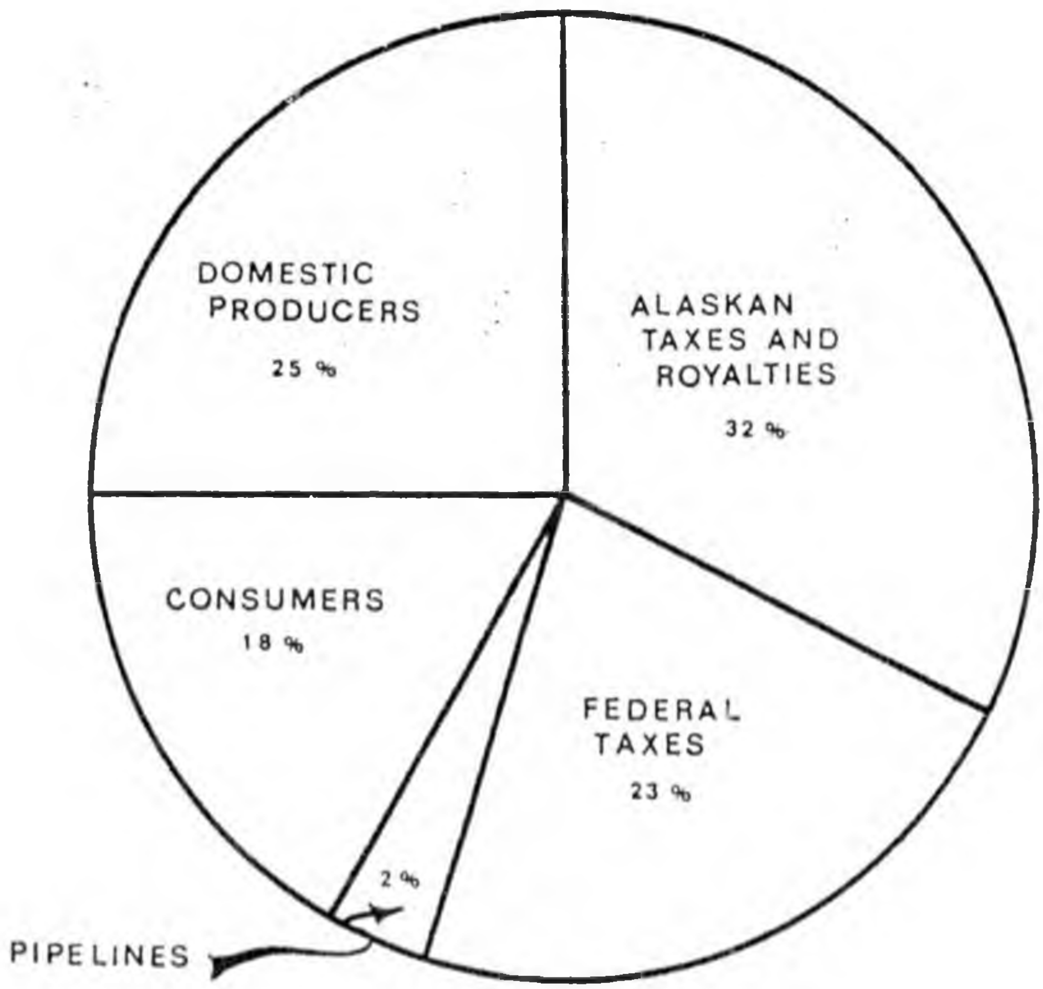
FIGURE S-2

SHARES OF NET NATIONAL ECONOMIC BENEFIT
(Base Case Assumptions)



fits. And pipeline benefits result from the special treatment of the investment tax credit allowed for these companies where their regulators are not free to flow-through the savings of the credit to consumers immediately.[10/]

Several important points emerge from the distributional analysis:

- The consumer benefit is the only share of the NNEB that varies significantly if the ANGTS costs or the gas value change. Any increased national benefits caused by higher than assumed alternative fuel prices would accrue entirely to consumers. Conversely, any lower prices of alternative fuels and any pipeline cost overruns would mainly shrink the size of the consumer benefit.

- The share of the benefit captured by producers arises because the maximum price set by the NGPA for Prudhoe Bay gas would be significantly above the expected incremental costs of the gas production. Consequently, the Act potentially allocates the major share of the ANGTS project's NNEB to producers of Prudhoe Bay gas in the form of domestic "producers surplus." Also because a portion of the gas is owned by a foreign corporation, some potential NNEB would escape the U.S. economy in the form of foreign "producers' surplus."

- The domestic "producers surplus," however, would translate into above-normal accounting profits before taxes. Since these are subject to income taxes, a major share of the NNEB would be captured by state and federal governments in the form of extra tax revenues.[11/]

- In addition, Alaska would receive a further share of the NNEB in the form of severance taxes and royalty payments on the production of Prudhoe Bay gas. For the base case, the sum of all extra government revenues accounts for 55 percent of the total NNEB.

10/ The meaning and development of these shares are described in greater detail in Section V of the report.

11/ Normal taxes are considered as real resource costs rather than as transfers of wealth.

Under the basic regulatory framework assumed for this work, producer, state, and federal benefits would be largely independent of the cost or value of the gas to consumers. Consequently, under certain reasonable and feasible scenarios the project would benefit the nation but could harm gas consumers economically.[12/] One assumption about this framework is especially critical in this regard. Specifically, imposition of the full costs of gas conditioning on gas purchasers would reduce the consumer share of benefits considerably, with consumers being worse off, relative to using distillate fuel oil, by more than $1.9 billion (mid-1979 dollars). Consumers would not only be receiving Alaskan gas without any major price advantage, but they would also have to bear most of the significant project risks that other parties are unwilling or unable to bear in return for full access to various project opportunities.

In addition to the allocation of the project's direct costs and benefits, the ANGTS also involves significant opportunities and risks that various project participants would assume. These effects result from uncertainty about future gas markets, the future regulatory environment, and the technical feasibility of constructing the project at currently estimated costs.

Regulatory policy will affect the allocation of these project opportunities and risks among gas consumers and project participants in important ways. For example, the question of who should bear the risks of ANGTS cost overruns or the risk that Alaskan gas cannot be sold remains, to a large

12/ Table V-1 summarizes the results for the scenarios examined.

extent, unresolved. This analysis did not focus on these issues, but because the allocation of risks will ultimately affect the distribution of the actual NNEB, the issues are important and are discussed briefly in Section V.

Overall, this analysis has found that the natio could reap large benefits from the proposed ANGTS project. But significant issues remain to be resolved by the Commission and other policymakers. Because the potential bene its remain great, it also is in the nation's interest that some allocation of project risks, costs, and benefits sufficient to attract all the necessary parties to participate in the effort and, thus, to bring Alaskan gas to lower-48 markets be developed as soon as possible. It is hoped that this analysis can illuminate further the difficult balancing problem faced by FERC in this matter.

I. INTRODUCTION

In 1976, Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA) (i) "to provide a means for making a sound decision" that provided for Presidential and Congressional participation, "as to the selection of a transportation system for delivery of Alaska natural gas"; and if a system were approved, (ii) "to expedite its construction and initial operation."[1/] The first step in the process established by the ANGTA was completed in May 1977 when the former Federal Power Commission (FPC) transmitted its Recommendation to the President.[2/] In its report, the Commission assessed the gas supply increases possible through the Alaskan North Slope gas discoveries as "crucial to this Nation's economy and well-being."[3/] The Commission then recommended the Alcan pipeline proposal which envisioned building a gas pipeline along part of the Trans-Alaska Oil Pipeline System right-of-way, then proceeding through Canada and delivering gas to the Midwest and West Coast.

In September 1977, the second step in the process established by the ANGTA was completed when the President issued his Decision that also supported the proposed Alcan system, asserting that Alaskan gas deliveries could provide

1/ ANGTA, Section 3.

2/ U.S. Federal Power Commission, Recommendation To The President: Alaska Natural Gas Transportation Systems, May 1977, (reprinted April 1978 by the U.S. Federal Energy Regulatory Commission), (hereafter referred to as the Recommendation to the President).

3/ Ibid., p. 1.

"critical supplies of Alaskan natural gas to U.S. markets."[4/] Congress then approved the President's Decision through a joint resolution. The concerns noted in the Commission's report and the President's Decision, which arose in the context of U.S. natural gas shortages during the early months of that year, focused primarily on insuring adequate supplies of natural gas to the highest priority gas consumers--homes, offices, and industries with special process needs for natural gas.[5/]

Events since 1977, however, have significantly alleviated earlier fears about natural gas shortages of emergency proportions in the near term. Specifically, the Natural Gas Policy Act of 1978 (NGPA), by providing the interstate market with a basis for better access to intrastate gas, appears to have alleviated the threat of immediate gas supply shortages for high priority gas customers. The new pricing mechanisms of the NGPA, along with the Powerplant and Industrial Fuel Use Act of 1978, also appear to have moderated demand for natural gas in the middle- to longer-term. Moreover, prospects have improved for increased natural gas imports from Canada and Mexico.

But while the short run natural gas supply picture has improved dramatically since 1977, the oil supply outlook has worsened, with domestic and world supplies becoming tight and with much elevated world oil prices. On the one hand, then, the improved near term natural gas supply picture raises new ques-

4/ Executive Office of the President, Decision and Report to Congress on the Alaska Natural Gas Transportation System, September 1977, p. xiv, (hereafter referred to as the President's Decision).

5/ Ibid., pp. 87-90.

tions about the old justification for proceeding at this time with the Alaska Natural Gas Transportation System (ANGTS). On the other, the increased likelihood of an oil supply crunch, during the early 1980's and beyond, raises new reasons for providing lower-48 markets access to known reserves of Alaskan gas.

As a result, the focus for interest in Alaskan natural gas has shifted away from simply avoiding natural gas supply shortages in the short run and toward insuring adequate supplies for high priority users and reducing energy imports in the middle- to long-term. The purpose of this report, then, is to analyze the major economic, market, and financing issues associated with the proposed ANGTS in light of these changed circumstances so that the Federal Energy Regulatory Commission (FERC) can use this assessment in deciding on the appropriate conditions to set for the ANGTS certificate of public necessity and convenience.

The changes in natural gas markets have created a situation in which the policy issues that accompany more widespread use of Alaskan gas are less straightforward than those associated with whether to maintain adequate gas supplies for today's high priority consumers. This analysis suggests a framework which can assist in illuminating these issues, based upon the following major policy questions that must yet be resolved by the Federal Energy Regulatory Commission as part of the process established by the ANGTA:

- Are there still net benefits to the nation from proceeding with the proposed Alaskan gas pipeline project?

- If the potential benefits remain significant, why must low cost old gas subsidize the project through rolled-in pricing of the Alaskan gas supplies and why may special regulatory treatment, such as "all events tariffs" to insure loan repayments even if no gas is ever delivered, be necessary?

- How does the planned implementation of the ANGTS affect other potential gas supply opportunities, especially Mexican gas purchases?

- What policy options, such as gas conditioning charges or wellhead price ceiling levels, exist for reallocation of project costs and how would these options affect the distribution of the project's net benefits?

This report first describes one key measure of whether the ANGTS project would be in the national interest, the Net National Economic Benefit (NNEB) and, then, explores the sensitivity of this measure to various future states of the world. The NNEB measures the attractiveness of the project from the national perspective, but since parties other than potential gas consumers may capture shares of the NNEB, the NNEB does not provide information about the potential attractiveness of delivered gas in energy markets. Therefore, this analysis also develops cost estimates for the delivered Alaskan gas and explores the sensitivity of these cost estimates to variations in several key parameters, including pipeline cost and gas flow rate changes.

Since the assessments of economic efficiency and marketability indicate that the project should benefit the nation and is potentially marketable, the analysis explores why traditional regulatory treatment in terms of pricing policy and allocation of project risks have presented problems for implementation of the project.

ASSESSING THE DESIRABILITY OF PROJECT IMPLEMENTATION

The first important policy question is whether the transportation of Alaskan gas to the lower-48 states can benefit the nation as a whole. Both the Federal Power Commission's Recommendation to the President and the President's Decision used a Net National Economic Benefit (NNEB) calculation as the primary indicator of project desirability from the national perspective.[6/]

The NNEB measure has important advantages and disadvantages. Most importantly, it provides a single measurement, in comparable terms, of the outlays of the nation's real resources required over time to bring Alaskan gas to consumers and the stream of benefits that result from their use of the gas. For the ANGTS, the benefits consist of the stream of real national resource expenditures otherwise required to provide consumers of Alaskan gas with an equivalent fuel. In this manner, the NNEB measures the economic efficiency of the ANGTS project. If the benefits are expected to exceed the costs, the NNEB is positive, and policymakers can conclude that the project would be efficient in an economic sense.

Although the NNEB calculation is a powerful indication of the merits of a project, its usefulness is more limited when decision makers must choose among several qualitatively different energy alternatives. When differences among alternative projects can be expressed entirely in a quantitative manner, the NNEB provides a means for direct comparison. Some projects, however, have

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6/ This methodology was first applied to the Alaska gas pipeline in a Department of the Interior report, Alaska Natural Gas Transportation Systems: A Report to the Congress Pursuant to Public Law 93-153, December 1975.

characteristics which are difficult to assess objectively and quantitatively, including :

- ... ...gical and cost uncertainties for which statistically-s...ificant experience does not exist;
- equity or distributional issues associated with the allocation of project costs and benefits; and
- externalities that are difficult to measure quantitatively such as the environmental benefits of additional natural gas use or the national security costs of energy imports.

Because criteria in addition to economic efficiency play an important role in decisions about U.S. energy policy, few opportunities arise for automatic decision making based on NNEB estimates or, for that matter, based on any strictly quantitative project assessment technique. Nevertheless, by serving as a benchmark, this NNEB analysis can help decision makers to focus their judgement on the worth of the qualitative advantages or disadvantages available from the alternatives applicable to an energy choice.

APPROACH TO FACILITATING IMPLEMENTATION

The ANGTS has generally been considered a private sector venture. Although federal loan guarantees for the ANGTS have been mentioned in the past and the Natural Gas Policy Act of 1978 (NGPA) permits rolled-in pricing of natural gas transported through the ANGTS in order to enhance its marketability, the NGPA Conference Report stipulates that no additional federal subsidy is to be provided to the pipeline.[7/] Thus, the federal government's major

7/ U.S. Congress, House of Representatives, "Natural Gas," Conference Report to accompany H.R. 5289, 9^th Congress, 2d Session, Report No. 95-1752, October 10, 1978, p. 103.

policy choices with respect to ANGTS will be expressed in the regulations formulated by FERC and in the conditions imposed in the pipeline's certificate of public convenience and necessity under which the project must be privately implemented.

For the Alaskan natural gas pipeline project to advance successfully as a private venture, many independent parties, each from their separate perspectives, must all reach favorable decisions about the prospects for the project and the attractiveness of the gas it would deliver. Beyond the federal government, major participants include the pipeline venture partners, potential lenders, Prudhoe Bay gas producers, state and local governments, and potential gas customers for Alaskan gas at wholesale and retail levels. These parties have different and often contradictory objectives. Consequently, in its deliberations on appropriate Alaskan gas tariffs and cost and risk allocations, FERC faces a difficult task in balancing these interests in a way which allows private sector implementation of the pipeline project to generate the broader net national economic benefits which the ANGTS can provide.

For the ANGTS, the decision process most likely will be guided by the classic goals of utility regulation: efficiency, equity, and revenue generation.[8/] As mentioned earlier, a positive NNEB indicates that the ANGTS would be economically efficient over a wide range of plausible assumptions. FERC, however, must establish tariffs to be charged for transportation of the

8/ For an expanded discussion, see James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, New York; 1961, pp. 291-294.

gas, and the tariff design may or may not encourage actual use of the gas in an economically efficient manner.

The important aspects of the equity goal are the fair allocation of costs to those benefitting from service and the minimization of windfall gains or losses among the relevant parties. Typically these first two goals, efficiency and equity, also must be weighed within the constraint that the tariffs must generate sufficient revenues to permit the pipeline owners to service their debt obligations and to earn a reasonable rate of return on their equity investment. For a project of the enormous scale, high unit costs, and large risks of the ANGTS, balancing these conflicting goals will be especially difficult.

The project sponsors expect a return on their equity investment commensurate with the technical, market, and regulatory risks that they accept. Potential lenders expect the funds that they lend to the project, as well as interest on their funds, to be repaid in any event.

Furthermore, each state or local regulatory body expects the terms of purchase offered to the gas distribution utilities within its jurisdiction to serve its constituents' interests as defined by its legislative authority. Finally, gas purchasers, both wholesale (direct industrial customers and distribution companies) and retail, expect Alaskan gas to be a competitively-priced and reasonably reliable fuel.

Thus, if the ANGTS is to proceed as a private venture it must deliver Alaskan gas at costs that allow the gas to be sold on terms which will be attractive to gas customers and will be acceptable to regulators. In principle, the marketability of the delivered gas could be assured in at least two ways. First, if Alaskan gas were delivered at low cost relative to other alternatives, sellers and their regulators could agree to prices naturally attractive to potential customers. Second, if Alaskan gas proved to cost more than alternative fuel options, then regulators could still utilize a gas pricing mechanism that would make the Alaskan gas supplies marketable. Since gas is generally priced on an average cost basis, high cost Alaskan gas could be averaged, or "rolled-in," with the "cushion" of lower cost gas to provide consumers with fuel priced below alternative fuels priced on an incremental cost basis.[9/] Traditional utility financing and ratemakin- methods generate high costs for delivering gas in a project's early years followed by low costs late in the project's useful life. Consequently, a project which is desirable on a lifecycle cost basis may appear prohibitively expensive at the outset.

This traditional approach--the historical embedded cost method--derives an annual revenue requirement which includes a rate of return on a rate base, defined as the undepreciated book value of the pipeline capital investment. As depreciation erodes the rate base over time, the revenue requirement decreases, and assuming that the annual quantities of gas delivered remain constant the allowed unit cost of pipeline transportation decreases.

9/ The size of the old gas price "cushion" that will be available at the time of Alaskan gas deliveries is quite uncertain because (i) the quantities of old gas that will actually be made available in the future under existing contracts are not known with precision and (ii) the extent to which gas companies may use up any available cushion to b[illegible] up prices on decontrolled natural gas supplies is not well understood.

In the case of the ANGTS, high transportation costs in the early years of the pipeline's operation could create initial marketability problems for Alaskan gas. In facilitating marketability through additional regulatory action, care should be taken to differentiate between regulatory actions that simply compensate for the upside-down time-profile of traditional gas tariffs and other actions that subsidize a fundamentally uneconomic source of gas supply. Otherwise, the hidden subsidy of regulatory support of an uneconomic gas source could lead to the use of a high cost energy source instead of a lower cost (but unsubsidized) source. Whether rolled-in pricing of Alaska gas would prop up a fundamentally uneconomic project or, instead, would simply reverse the adverse effects of traditional ratemaking is evaluated throughout this analysis.

Assurances of Alaskan gas marketability would, in turn, improve the outlook for the pipeline project sponsors' ability to arrange financing. Uncertainty about project costs and about the prices of potential fuels which would compete with Alaskan gas largely cannot be eliminated until the ANGTS is actually built and operating. Because of these factors, plus the large scope of the venture, providers of equity and, in particular, debt most likely would support the project only if they perceive an irreversible commitment which would guarantee the marketability of the gas.[10/] If necessary, such a com-

10/ A lack of symmetry in the distribution of claims to any greater than expected benefits flowing from the project may reinforce this investor viewpoint. As will be shown in a later section, consumers capture almost all of the potential NNEB on the upside. And this absence of any major upside potential may justify project sponsors' and lenders' search for assurances that their investment and returns would be insured on the downside, at least with respect to catastrophic events.

mitment could be subject to conditions that the project demonstrate competent management, etc., but probably could not otherwise be a function of the ultimate actual costs for which Alaskan gas would be delivered or of the price of alternative fuels available when the ANGTS would become operational.

A final point about the history of natural gas regulation should be noted here. Theoretically, potential gas users should be indifferent between two long term supply contracts, one with a tariff high in the early years and low in later years resulting from the gas pipeline ratemaking methods and the other with equal annual payments whose present value, calculated at the purchaser's discount rate, equalled the present value of the traditional tariffs. Nevertheless, a large industrial gas user, which might purchase Alaskan gas directly from an interstate pipeline under a long term contract and a separate rate schedule, might be unwilling to do so. Interstate transmission companies and gas distribution utilities have been forced throughout the 1970's to curtail gas deliveries to customers deemed to be low priority by federal gas curtailments policy. As a result, large industrial customers have little confidence that the sanctity of any long term gas supply contract could be preserved in the face of shortages affecting higher-priority customers. And they suspect that once the Alaskan gas prices began to be more attractive, their gas supplies would be curtailed.

As a result, past and present natural gas regulation could be a major reason that a large, capital intensive gas supply project such as the ANGTS might require pricing or other regulatory arrangements different from those appropriate for conventional gas supplies. The ANGTS also involves serious uncertainties in terms of both project costs and the atmosphere of public sentiment in which the project must be implemented. Therefore, unusual regulatory action might be required to develop an equitable allocation of the project's opportunities and risks.

ORGANIZATION OF THE REPORT

The next part of the report, Section II, shows that the ANGTS reasonably can be expected to produce an NNEB in the range of ten to twenty billion dollars (mid-1979 dollars). The analysis considers a number of alternative sets of assumptions and explores the sensitivity of the NNEB to changes in projected costs, gas values, and completion schedules.

Section III estimates the delivered cost of gas for the project under alternative assumptions. Both the time-profile of gas costs under traditional ratemaking and an annuity-equivalent cost are presented. This section also examines the sensitivity of the delivered cost of the gas to the relevant changes considered in Section II.

The fourth section utilizes the delivered gas cost information developed in Section III to analyze the potential marketability of natural gas from Alaska. It discusses the appropriate basis for comparing fuel alternatives from the perspective of the gas purchaser and notes the problems with the single-year and time-average comparisons that are encountered in many assessments of Alaskan gas and alternative energy supplies. This section also compares the time-profile of prices for Alaskan gas and alternative fuels. The implications for the nation of likely end user choices are also considered in this section.

Section V examines who would receive the project's benefits and who would pay for them. It also explores the reasons why so-called special tariff treatment, such as rolled-in pricing of some ANGTS costs and guaranteed repayment of lenders, may be necessary and appropriate despite the fundamental economic advantages of the pipeline project and probes whether these steps truly would represent "special" treatment for the ANGTS in the 1984 timeframe envisioned for initial operation of the project. The final section reviews the findings and conclusions of the analysis.

CAVEATS

Although the NNEB estimates in this analysis indicate that the project should benefit the nation under all but the most disastrous conditions, several caveats apply to the results. These caveats deal with the gas transportation costs, the gas value, the method for determining real resource costs, and some simplifying assumptions underlying our entire analysis.

An independent assessment of the reasonableness of the ANGTS cost estimates is beyond the scope of this analysis. Although we explore costs beyond the range considered feasible in the earlier Federal Power Commission analysis and the President's Decision, no more recent pipeline cost data are available to indicate whether the large overruns considered in Sections II and III are likely to occur. Rather, in light of the Trans-Alaska Pipeline System (TAPS) cost overrun experience, we elected to estimate the NNEB and the delivered cost of gas for a case where the cost overruns for the Alaskan segment of the ANGTS would be analogous to the TAPS experience.

The gas production costs used here are the latest estimates that we have found, but these estimates appear to be quite rough. Changes in these costs could affect NNEB estimates, but since these costs would not affect the wellhead gas price over a wide range, production cost changes would not change the delivered cost of gas.

Gas conditioning costs are drawn from a September 1978 engineering study.[11/] In this analysis we assume that producers pay for gas conditioning as part of the production process; consequently, conditioning cost changes would have the same effects as changes in other gas production costs. The issue, however, of who will pay for gas conditioning is not yet resolved. If pipelines must pay these costs, then gas conditioning cost changes would affect the delivered gas cost as well as the NNEB estimates.[12/]

With respect to the marketability and financial feasibility of the Alaskan gas project, our analysis suggests that, if the ANGTS is built for its expected cost, then economically rational consumers with the correct information would agree to purchase the gas. Nevertheless, efforts to proceed with the project could be stymied by (i) institutional requirements that gas purchase commitments be made prior to finalizing the construction financing, (ii) uncertainty about Alaskan gas transportation costs and, (iii) uncertainty about the future prices of the fuels with which Alaskan gas must compete. And

11/ Ralph M. Parsons, Inc., "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska," September 1978.

12/ Since the reduction of production costs associated with pipeline payments for conditioning would lead to greater surplus producer revenues, it would increase the foreign producer benefits and, thus, lower the NNEB.

as mentioned earlier, the time-profile of traditional gas tariffs could also hinder efforts to market the gas. Since this analysis does not examine in detail where and to what class of users the gas might be sold, our conclusions about the marketability of Alaskan gas are necessarily based on broad comparisons of citygate costs of Alaskan gas and costs of alternative fuels.

Other important simplifying assumptions and caveats are presented where relevant throughout the remainder of this analysis.

II. PROJECT NET NATIONAL ECONOMIC BENEFITS

As noted in the introductory section, several measures are available for evaluating the attractiveness of the Alaskan natural gas project. Delivered cost of gas calculations focus on consumers by comparing the project's costs to potential gas users with their costs for alternative sources of fuel. Another approach focuses on the U.S. and examines the economic efficiency of the project; that is, it evaluates whether or not the project produces savings of real resources for the nation as a whole. The measure of these savings is called Net National Economic Benefit, or simply NNEB.

This section examines the attractiven the project according to this NNEB measure. It reviews the significance of the uncertainties surrounding the components of the NNEB analysis--most notably the project construction costs and the value of the gas to consumers. By examining the extent to which the NNEB varies over reasonable ranges of values for its components, policy-makers can assess their confidence in the conclusions drawn from the base case set of assumptions described later in this section.

Before proceeding, we should note that the NNEB and consumer cost measures can provide contradictory assessments of the attractiveness of the project. Some cases presented in this section describe situations which generate sizeable positive net national economic benefits but which also lead to streams of consumer costs for Alaskan gas in excess of the streams of costs for the fuel whose use would be displaced. The divergence between these two measures stems from the fact that NNEB considers the net benefits received by all project participants including, but not limited to, consumer benefits. In this sense, the NNEB analysis does not assess the distribution of benefits among sectors of the economy. From the overall perspective of national economic efficiency, losses by consumers can be compensated for by increased gains to producers, pipeline companies, and the general taxpayers of the state of Alaska and of the federal government. The important distributional issues associated with the ANGTS project are examined in Section V.

COMPONENTS OF NNEB

Net national economic benefit, as noted before, is a measure of the project's net savings of real resources to the nation as a whole. The difference between real resource costs (or savings) and the normal accounting definitions of costs is a significant one. Real resource costs represent the economic costs associated with physical resources actually consumed in the production of goods and services and a return on these expenditures. Thus, all payments representing the transfer of purchasing power from one party to another without any utilization of resources would be excluded from real resource costs. For example, Alaskan state royalty and severance taxes appear to cover no specific consumption of real resources incurred by the state in connection with gas production. Instead, they merely transfer wealth from Prudhoe Bay gas producers, lower-48 gas consumers, or U.S. taxpayers to the state of Alaska; consequently, these two items have not been treated as real resource costs for purposes of the NNEB calculation.[1/]

1/ They, however, have been included in the calculation of the delivered cost of Alaskan gas which consumers would pay .

Included as components of real resource costs are all costs of material and labor, as well as allowances for taxes and returns on capital at rates that would be expected in normal business activity. This analysis groups the components of NNEB into the following four categories:

- Gas value: This value is the real resource savings that would result from using Alaskan gas instead of some other equivalent fuel; that is, it equals the unit price of the alternative fuel multiplied by the quantity of the fuel displaced by Alaskan gas.

- Production costs: These costs are the incremental real resource costs associated with gas production from Prudhoe Bay. As such, they do not include the costs of installing facilities which already are planned for the production of Prudhoe Bay oil. The major incremental costs of Prudhoe Bay gas production will be the capital investment for the gas conditioning system and water-flood facilities.2/

  Other real production costs include operation and maintenance of the production facilities as well as *ad valorem* taxes paid by producers. The latter have been included as a real resource cost on the assumption that these taxes serve as a surrogate measure of the infrastructure expenditures to which the Alaskan public would be committed in order to facilitate the gas production (e.g. additional roads and schools). For similar reasons, state and federal income taxes, at rates levied on normal levels of producer income from Prudhoe Bay gas production, are included as an approximation of the general government costs required to support the production activity. Also, inclusion of income taxes is necessary in order to maintain consistency with the treatment of other private sector investments and with other components of the NNEB calculation (i.e., the benefits stream), both of which include income taxes.3/

2/ Inclusion of gas conditioning cost as a production cost (rather than as a transportation cost) is based upon a proposed FERC rulemaking.

3/ The analysis imputes income taxes as a part of the calculation of the opportunity cost of capital by developing annuity-equivalent capital costs for the period of project operations, based on the actual capital outlays for the project and a 10 percent real before-tax discount rate. This approach, recommended by the Department of Energy (DOE), is described in greater detail in the discount rate discussion later in this section.

- Transportation costs: For the U.S. segments of the gas pipeline, these costs include constructi outlays as well as operation and maintenance expenses. Other U.S. costs include income taxes and state *ad valorem* taxes on the pipeline activities. For the Canadian segments of the line, the United States would incur real resource costs through cost of service payments to C-nadian carriers. The U.S. share of Canadian pipeline costs depends upon relative shares of the total throughput as well as cost overruns on the Canadia.ı segments. The formulae with which these shares are determined were established in the joint United States/Canada pipeline agreement.4/

- Net foreign profits: Foreign interests own a share of the Alaskan gas. The revenues to a foreign oil company that exceed direct and indirect gas production costs are essentially net project costs for the nation, since they escape our economy and, in so doing, provide no benefits for the United States.5/

The net national economic benefit of the proposed project is the present value of the stream of benefits that results from subtracting the three cost components from the gas value to consumers. That is:

NNEB = Gas value - Production costs - Transportation costs - Net foreign profits.

The estimates of gas value and costs affect the NNEB calculations in important ways, as does the choice of discount rate and time period over which the ANGTS project is examined. The discount rate chosen for the NNEB calculation ideally should represent society's rate of time preference; that is, the rate of return at which society is prepared to forego consumption today in

4/ Refer to President's Decision, pp. 47-83, for a summary of this agreement.

5/ Revenues paid to foreign nations are a real resource cost to the U.S. because they represent a future claim on U.S. goods and services.

trade for some greater amount of consumption later on.[6/] The actual project life would depend upon the useful physical lifespan of the pipeline, the design capacity of the pipeline, and the magnitude of recoverable gas reserve which can be economically produced over time.

The remainder of this section describes the set of assumptions which describe the "base case" scenario and explores the sensitivity of the NNEB to alternative assumptions concerning the value of the delivered Alaskan gas, the project life, and the transportation costs.

BASE CASE ANALYSIS

The analysis of the ANGTS used for the President's Decision provides most of the baseline data for the base case used in this analysis. The President's Decision and our base case assume:

- Alaskan gas substitutes for imported distillate fuel oil on a one-for-one, energy equivalent basis and has a gas value equal to the wholesale price of distillate.[7/]

6/ E. J. Mishan, Cost-Benefit Analysis, Praeger Publishers, New York, 1976, pp. 201-203.

7/ This assumption ignores potential changes in total U.S. energy consumption that could be caused by rolled-in or average pricing of Alaskan gas at the retail level compared to marginal cost pricing of distillate fuel oil. If considered fully, it is not clear whether careful consideration of differences in retail pricing would increase or decrease our NNEB estimates, but it is likely that the effect would be small compared to other factors ultimately likely to impinge on the NNEB. Furthermore, technically correct treatment of this effect is complicated by the fact that, early in the project life, Alaskan gas may cost more than the average of all other flowing gas; but late in the project life the opposite may occur. Finally, it also would require an assumption about whether biases of any similarly kind (e.g., domestic price controls on crude oil or refined petroleum products) will affect distillate prices over the life of the ANGTS project.

- strictly for purposes of simplifying the analysis, that a decrease in U.S. demand for world oil, provided through the development of Alaskan gas, would not affect world oil prices.
- an average pipeline construction cost overrun of 30 percent.
- a pipeline debt/equity ratio of 75/25.
- start-up in January 1984.
- gas deliveries to the pipeline of 2.4 Bcf/day and net gas deliveries at the citygate based on overall pipeline gas consumption for the original Arctic gas displacement scheme.8/
- the U.S. portion of cost of service payments for facilities shared with Canada vary as a function of relative volumes of U.S. and Canadian gas, with the U.S. share equal to 76.4 percent for U.S. shipments of 2.4 BCF/day and Canadian shipments of 1.2 BCF/day.
- the U.S. share of cost of service payments for the Dempster lateral varies on the basis of overruns on the Canadian main line, overruns on the Dempster line, and the relative U.S. and Canadian volumes of gas shipped.9/

The NNEB calculations in this analysis are denominated in mid-1979 dollars, and all benefit and cost streams are discounted to mid-1979 using a real after-tax discount rate of 6 percent. Cost data from the President's Decision, which had been denominated in 1975 dollars, were converted to mid-1979 dollars using the aggregate U.S. GNP implicit price deflator. Non-residential

8/ This scheme is used here because it is embedded in internal FERC models of the ANGTS project. To our knowledge, detailed documentation of this displacement plan is not available.

9/ A description of the formula for computing the U.S. share is shown in the President's Decision, op. cit., pp. 72-79 and 168-174.

construction price deflator projections were applied to construction costs.[10]

Other important elements of the base case include the following:

- gas processing costs for a 2.4 Bcf/day output stream were based on a linear extrapolation to the higher capacity using best-available cost data for a 2.0 Bcf/day plant.[11]

- incremental water-flood requirements were assumed to be approximately 73 percent of the Prudhoe Bay unit's total water-flood requirements.[12]

- _ad valorem_ taxes of 1.7 percent were applied to the depreciated book value of the pipeline and the depreciated replacement value of the gas production equipment.[13]

- Alaskan state income taxes were assumed to be 9.4 percent of pipeline net income and "normal" producer net income.[14]

10/ Data Resources Inc., The Data Resources U.S. Long-Term Review, Winter 1979 TRENDLONG 2003 projections. See Appendix G for the inflation adjustments used in this report.

11/ Ralph M. Parsons, Inc., "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska," September 1978.

12/ Water-flood facilities investment has been estimated at $2 billion (1979 dollars), as suggested in Oil and Gas Journal, February 26, 1979, p. 70. Half of the expenditures are assumed to occur in 1983 and half in 1984. The incremental portion of the outlays for water-flood facilities has been estimated by comparison of alternative production possibilities presented in a report by H. K van Pollen and Associates, Inc., Documentation of Input Variables, Northern Alaska Hydrocarbons Model, August 1978.

13/ The _ad valorem_ rate and its application to the pipeline on the basis of depreciated book value are carried over from models used in connection with the President's Decision. It is our understanding that these taxes would be assessed at a 2.0 percent rate and would be based on replacement value; this, however, presents a minor difference that does not affect the results significantly.

14/ "Normal" net income is defined as that level yielding an overall 8 percent after-tax return on total capitalization. See Appendix A for the derivation of "normal" net income.

- federal income taxes were assumed to be 46 percent of pipeline net income (after state income taxes), adjusted for the effect of a 10 percent income tax credit.

- the rates of return on pipeline equity were based on the Commission's latest incentive rate of return proposal.15/

- foreign profit calculations were based on British Petroleum's 52 percent interest in Standard Oil of Ohio's 23.5 percent of Alaskan gas.16/

- low world oil price escalation, as defined in the Energy Information Administration Annual Report to Congress.17/

These inputs and assumptions yield an NNEB estimate of $14.9 billion (mid-1979 dollars). The components of this estimate are:

Gas value	$33.3	billion (mid-1979 dollars)
- Production costs	6.0	
- Transportation costs	11.9	
- Net foreign profits	0.5	
NNEB	$14.9	billion

Thus, the proposed ANGTS project would provide significant economic benefits to the nation under the base case inputs and assumptions.

In contrast to ICF's base case estimate, the President's Decision estimated an NNEB of $5.8 billion (1975 dollars). The following table presents

15/ FERC, "Notice of proposed rulemaking to set values for incentive rate of return and establish change-of-scope and inflation adjustment procedures and request comments on filed tariffs," Docket No. RM 78-12, April 6, 1979.

16/ Sources: Arlon R. Tussing and Connie C. Barlow, "An Introduction to the Gas Industry with Special Reference to the Proposed Alaska Highway Gas Pipeline," Institute of Social and Economic Research, Anchorage, Alaska, October 25, 1978, p. I-37 and British Petroleum, Annual Report, 1978, p. 12.

17/ The President's Decision assumed a constant real oil price. President's Decision, p. 97.

our current understanding of the reconciliation between the earlier estimate and our current base case NNEB estimate.

Step		Billions
	President's Decision NNEB	$ 5.8 (1975 dollars)
1.	Denominate in mid-1979 dollars	+ 1.4 (mid-1979 dollars)
2.	Add Water-Flood Costs	- 1.6 (mid-1979 dollars)
3.	Adjust Transportation Costs	+ 0.2 (mid-1979 dollars)
4.	Unreconciled Changes	- 0.5 (mid-1979 dollars)
5.	Discount to mid-1979 Timeframe	+ 1.[illegible] (mid-1979 dollars)
6.	Change Discount Rate (10% to 6%)	+ 4.5 (mid-1979 dollars)
7.	Alter Distillate Price Trajectory	+ 3.3 (mid-1979 dollars)
	ICF Base Case NNEB	$ 14.9 (mid-1979 dollars)

Some of these steps are simply accounting changes to update the basis for the estimate (steps 1, 5). Others incorporate later cost data and DOE's recently established standardized capital cost methodology (steps 2, 3).[18/] The 10 percent real discount rate used throughout the President's Decision is appropriate for considering a project's capital cost stream, and we adopt this same approach. For reasons elaborated later in this section, however, we believe that a 6 percent real discount rate is a more appropriate measure of society's time preference and, therefore, a preferable rate to use in discounting the project's overall streams of costs and benefits (step 6).

Finally, we believe that in light of recent world oil price developments an assumption of constant real prices would be optimistic beyond a reasonable limit. Instead, we have essentially applied the low oil price escalation expectations of the Energy Information Administration Annual Report to Congress to the distillate fuel oil price in the President's Decision (step 7).

18/ The DOE methodology is discussed later in this section.

About $0.5 billion (mid-1979 dollars) in difference remains unexplained (step 4).

SENSITIVITY ANALYSIS

Several of the input estimates used to calculate the NNEB could vary significantly from the base case values. Sensitivity analysis provides insights about the relative importance of changes in the discount rate, gas value, useful project life, and pipeline construction costs. In addition, the order of magnitude of the minimum likely effect of the ANGTS on world oil prices and required U.S. payments for imported oil are estimated because lowered world oil prices both benefits the nation and affects the value of Alaskan gas.

Discount Rate

The base case uses a 6 percent real after-tax discount rate to account for the time preference of society. No strong empirical basis currently exists to identify society's time preference, but the after-tax real rate of return on private investments represents one reasonable, yet conservative, approximation of this rate.[19/] The 6 percent rate chosen for the base case appears to approximate the private after-tax rate of return.

19/ Conservative refers to avoiding over-investment in capital-intensive projects such as the ANGTS. It is conservative, we believe, because the effects of personal income taxes on returns to individuals in the form of after-tax corporate income suggest the use of an even lower rate to represent social time preferences. Consequently, it could be argued that conservation recommends the lower rate to guard against under-investment in capital-intensive domestic energy supply and conservation projects.

This choice of discount rate is based mainly upon a recent Department of Energy (DOE) directive on standard financial treatment of cost estimates.[20/] The directive recommends using a real rate of return on equity of 9.5 percent, after tax; a real interest rate on debt of 3 percent; and a 6 percent inflation rate.[21/] Assuming an overall marginal corporate income tax rate of 50 percent a typical capital structure, comprised of one-third debt and two-thirds equity, yields a weighted-average after-tax rate of return of approximately 5.9 percent.

Although a 6 percent after-tax rate is, we believe, appropriate for discounting the project's overall resource cost and gas value flows, the Department of Energy (DOE) has recommended using a before-tax rate of 10 percent as a means of accounting for all the real resource costs associated with the capital expenditure portion of an energy project.[22/] Use of a before-tax rate for capital expenditures captures the returns foregone on alternative private sector investments that would have accrued to (i) equity holders as dividends and/or capital gains, (ii) lenders as interest payments, and (iii) the government as corporate income taxes.[23/] DOE recommends accounting for

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20/ Attachment C of DOE, Stuart W. Ray, Policy and Evaluation, "Financial Costing Guidance for Policy and Fiscal Guidance," memorandum for distribution, March 28, 1979.

21/ DOE, Stuart W. Ray memo, op. cit., Attachment 6.

22/ DOE, Stuart W. Ray memo, op. cit., Attachment 6.

23/ Corporate income taxes are treated as real resource costs because they represent the project's "portion of the fixed costs of government operation." See DOE, Gary Dorman, "The treatment of taxes in cost benefit analyses," memorandum for Darius Gaskins, Deputy Assistant Secretary, Policy and Evaluation, August 8, 1978.

all of these opportunity costs of capital expenditures by using the before-tax, marginal rate of return on private sector investments, and it cites empirical evidence for using 10 percent as this marginal rate.24/

This analysis uses the 10 percent before-tax rate to estimate the real resource costs associated with the ANGTS project's capital expenditures because this approach is "neutral" with respect to any special tax treatment or financing methods available to this one project.25/ The NNEB calculations implement this procedure by, first, annuitizing the project's capital expenditures using the 10 percent discount rate. Then, the project's overall benefit and cost streams (including the annuitized capital expenditures) are discounted at 6 percent in order to estimate the present value of the ANGTS project's overall NNEB.

Earlier work has included estimates based on a 10 percent rate of discount on the project's overall cost and benefit streams. Because this rate provides an extra-conservative appraisal of the project's net benefits, our analysis also presents NNEB estimates generated by applying a 10 percent discount rate to the project's overall benefit and cost streams whenever the information may provide useful insights. Under the base case assumptions, the NNEB estimated

24/ DOE, Gary Dorman, "Choosing the discount rate for NESS cost/benefit analyses," memorandum for Darius Gaskins, September 18, 1978.

25/ These "tax-neutral" cost estimates do not depend upon the corporate tax structure of the particular parties making the capital outlays, which is an appropriate feature for calculating net benefits from the national perspective. If actual tax payments were used as the real resource cost estimates, the NNEB estimate for the ANGTS project could vary significantly according to the share of capital outlays assumed to be made by oil companies and gas utilities.

using 10 percent is $8.1 billion, 46 percent below the base case estimate.

Gas Value

The base case assumes that Alaskan gas substitutes for distillate fuel oil on an energy-equivalent basis. It is worth reiterating that a primary reason for making this assumption is to maintain consistency with analyses prepared in connection with the President's Decision. We have performed no analyses to verify that Alaskan gas would substitute for distillate fuel oil rather than for less expensive fuels such as residual fuel oil.

Although OPEC oil prices have remained level in real terms, or even decreased slightly, for much of the period since the 1973 Arab oil embargo, recent events make such continued good fortune for oil consumers appear unlikely. Nevertheless, it is worth examining the economic attractiveness of ANGTS if oil prices were to remain constant in real terms throughout the project's life. The NNEB for a constant distillate fuel value, $11.6 billion, is 22 percent lower than the base case estimate (see Table II-1).

The base case projections of distillate fuel oil prices are drawn from the low price escalation scenario assumptions of the forthcoming Energy Information Administration's (EIA) Annual Report to Congress (ARC). The ARC's low price escalation assumptions are summarized in Table II-1.[26]

26/ In constant 1979 dollars, the crude oil price assumed in this EIA case is $16.00 per barrel from now through 1992, after which it escalates at a real annual rate of 2.8 percent. This compares with crude oil (contract) prices today of approximately $18.00 per barrel and spot market transactions in the $30-35 per barrel range.

TABLE II-1

NNEB ESTIMATES FOR SELECTED GAS VALUE ASSUMPTIONS[a/]

Gas Value Equal to:	Price Trajectory	NNEB (mid-1979 billion dollars)
Distillate Fuel	Constant[b/]	$11.6 billion
	Low Escalation[c/]	14.9
	Medium Escalation[d/]	22.3
Residual Fuel	Low Escalation[e/]	11.8

a/ Base case assumptions for other parameters.

b/ Distillate price: constant $2.62/MMBTU (1975 $).

c/ Base case distillate price: constant $2.62/MMBTU (1975 $) through 1992; 2.8% real escalation annually thereafter; $5.15 (1978 $) ceiling price.

d/ Distillate prices: constant $2.62/MMBTU (1975 $) through 1985; 4.5% real escalation annually to 1990; 4.7% per year thereafter; $5.15 (1978 $) ceiling price.

e/ Residual price: constant $2.84/MMBTU (1978 $) through 1992; 2.8% real escalation thereafter.

NOTE: These projection rules are denominated here in differing-year dollars in order to correspond with the various sources from which they were derived. The base distillate price, $2.62, is the adjusted figure used in internal FERC models for the $2 50 (1975 dollars) figure in the President's Decision. The base residual price is derived from National Energy Supply Strategy data expressed in 1978 dollars. In our NNEB calculations, however, both base figures are converted to mid-1979 dollars and projected using the oil price escalation rules of the Energy Informtion Administration Annual Report to Congress (low price escalation: Series C low; medium price escalation: Series C).

Distillate fuel oil prices, however, may also escalate more rapidly than these low price escalation projections. Table II-1 also presents the NNEB estimate for the ARC medium price escalation scenario assumptions. This NNEB estimate, $22.3 billion, is 50 percent above the base case. Consequently, the future course of world oil prices exerts large leverage on the net benefits of the ANGTS project. If world oil prices rise faster than the base case assumptions, the benefits to the nation would increase. And as will be discussed later, consumers would capture the full share of the increased benefits.

Thus far, the discussion of the gas value has assumed that Alaskan gas would substitute for distillate fuel oil. If overall gas supplies were plentiful at the time Alaskan gas was delivered, Alaskan gas might displace residual fuel oil. As a consequence, the value of the Alaskan gas would be the lower price of residual fuel rather than the price of distillate fuel. Under low world oil price escalation, the NNEB estimate based on the price of residual fuel oil remains in excess of $11 billion (see Table II-1).

Project Life

Legislative guidelines emphasize a 20-year period for analysis of the cost of service issues associated with the ANGTS.[27/] In turn, most NNEB analyses of the ANGTS have examined a similar time period (25 years). The typical useful physical life of a pipeline, however, approaches 50 years; for example, the President's Decision mentions the likelihood that the ANGTS might operate

27/ For example, see the Alaskan Natural Gas Transportation Act of 1976, Section 5(c).

for more than 40 years.[28/]

There is a realistic possibility that sufficient Alaskan gas reserves will be developed to utilize the pipeline well past the 25-year period assumed in our NNEB calculations.[29/] The useful life of the pipeline exerts a strong influence on its economic value to the nation. If the ANGTS were to deliver 2.4 Bcf/day for 30 years, the NNEB would rise to $17.7 billion (mid-1979 dollars). And an even longer useful life would further increase the NNEB (see Table II-2).

TABLE II-2

NNEB ESTIMATES FOR
ALTERNATIVE PROJECT LIFETIMES[a/]
(mid-1979 dollars)

Project Life	NNEB	
	(6% discount rate)	(10% discount rate)
20 years	$11.2 billion	$ 6.6 billion
25	14.9 billion	8.1 billion
30	17.7 billion	9.1 billion
50	23.5 billion	10.5 billion

a/ Base case assumptions used for other parameters.

The effect of the discount rate assumption, discussed previously, is especially dramatic in the case of an extended project life. With the 6 percent discount rate, the 50 year NNEB estimate would reach $23.5 billion, an

28/ President's Decision, p. 163.

29/ Data Documentation for Alaskan Hydrocarbons Supply Model, draft Technical Memorandum prepared by Division of Oil and Gas Analysis, Department of Energy, pp. 1^-12.

increase of 58 percent over the 25 year base case estimate.30/ In contrast, a 10 percent discount rate decreases both the absolute and relative importance of project benefits beyond the first 25 years. If a 10 percent discount rate were applied, doubling the life of the project would increase the present value of the NNEB by only 30 percent.

Pipeline Construction Costs

Few recent major construction projects have been completed at or below their initially estimated costs.31/ The cost overruns experienced by the Trans-Alaska Pipeline System (TAPS) were especially large. Compared with an original (adjusted) estimate of $1.6 billion, the capital cost of TAPS ultimately reached $7.7 billion, an increase of approximately 380 percent.32/ The unprecedented scale of the ANGTS project, coupled with the need to construct the Alaskan segment and a minor part of the Yukon segment in the same harsh Arctic environment in which TAPS was constructed, raises the prospect of large cost overruns for the Alaskan gas pipeline.

This section examines the potential effects of serious cost overruns for the Alaskan gas pipeline project. Importantly, the probability of large cost overruns varies significantly among the individual segments of the pipeline. In this context, then, the analysis examines how cost overruns on the various

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30/ The 50-year case represents a rough estimate which excludes any additional capital expenditures required to extend the operational period.

31/ See Walter J. Mead, Transporting Natural Gas from the Arctic, American Enterprise Institute, 1977, pp. 88-89, for an illustrative list of recent projects.

32/ Ibid., pp. 88-89.

segments could affect expected costs and project benefits.

Lower-48. Gas pipeline construction in the lower-48 involves a low probability of major cost overruns. Typically, lower-48 gas pipelines are constructed at a cost within 5 percent of the initial estimate.[33/] Approximately 21 percent of the value of the ANGTS plant-in-service would reside in the lower-48.[34/] Since the danger of significant cost increases appears remote for the lower-48 segment of the project, this analysis focuses on the Alaskan and Canadian segments.

Alaska. The Alaskan segment of the ANGTS must be constructed in the same hostile environment that the TAPS project faced. There are, however, important differences in the construction of gas and oil pipelines, including the ability to pipe gas at temperatures low enough to avoid thawing permafrost and to lay gas pipeline in the ground rather than above it. Both of these differences should lessen the ANGTS construction problems, with the one exception of burying gas pipeline in areas of discontinuous permafrost, where the chilled gas may cause frost heaving.[35/] Discontinuous permafrost could be encountered along approximately half of the Alaskan segment.

Fortunately, the Northwest Alaskan Pipeline Co. (formerly Alcan) proposal for the Alaskan segment follows the TAPS project chronologically. Consequently, this second pipeline construction effort can take advantage of

33/ Private communication from FERC staff.

34/ The plant-in-service estimate is based on the base case figures for the first year of the ANGTS operation.

35/ For a more detailed discussion, see the President's Decision, pp. 187-188.

lessons learned about pipeline construction in an Arctic environment. Moreover, the Northwest project will utilize the infrastructure created by Alyeska, the TAPS project manager, thus minimizing the chance of infrastructure-generated cost increases or delays over the share of the Alaskan segment laid parallel to TAPS. The TAPS experience should also lessen the chance for labor supply problems in Alaska, because the first effort expanded Alaska's pool of skilled workers.[36/]

Despite these advantages, unforeseen technological and management problems are likely to occur. In order to cover such contingencies, the President's Decision incorporated a 30 percent cost increase and one year start-up delay in the Alcan's (now Northwest) initial estimates.[37/] Our base case assumptions also follow this precedent.

Nevertheless, the 380 percent cost overrun for TAPS suggests that the implications of even more substantial cost overruns should be explored. Table II-3 summarizes the effects on the base case NNEB of cost increases for the Alaskan segment of 30, 100, 200 and 400 percent over current filed estimates. Even at four times the filed cost estimates for construction of the Alaskan segment, the NNEB remains significantly positive, at approximately $10 billion (mid-1979 dollars).

Canada. The remaining 2,028 miles of the pipeline system would be constructed in Canada. Approximately 40 miles of the Canadian segment should experience similar difficulties associated with Arctic and semi-Arctic condi-

36/ Ibid., pp. 138-144.

37/ Ibid., p. 150.

TABLE II-3

NNEB ESTIMATES FOR SELECTED CONSTRUCTION COST SCENARIOS[a/]
(mid-1979 dollars)

Cost Scenario	NNEB ($ billion)	Change From Base Case (percent)
ALASKAN OVERRUN		
0% (filed costs)	15.8	+ 6%
30% (base case)	14.9	--
100%	14.3	- 4
200%	12.7	-15
400%	9.6	-36
CANADIAN OVERRUN		
0% (filed costs)	15.7	+ 6
40% (base case)	14.9	--
100%	13.6	- 8
COMBINED CHANGES		
filed costs, all segments	16.8	+13
expected costs, all segments[b/]	14.9	--
"high cost" scenario[c/]	10.4	-30

a/ Base case assumptions used for other parameters.

b/ Base case.

c/ 132 percent Alaskan overrun, 102 percent Canadian overrun (derived from DOI/DOT "worst case" analysis). U.S. Department of the Interior, U.S. Department of Transportation, Alaska Natural Gas Transportation Systems: White House Task Force Lead Agency Report on Construction Delay and Cost Overruns, July 1, 1977.

tions. Other potential problems with the Canadian segment, however, could lead to significant cost increases, including:

- Canadian pipeline companies may have been over-optimistic in their construction labor productivity estimates for the ANGTS.[38/]

- Requirements for constructing the Canadian segments of the ANGTS with Canadian goods could (i) force builders to use more costly goods than necessary, or (ii) create artificial supply bottlenecks that directly or indirectly raise costs.

The President's Decision and our base case address this concern by incorporating a 40 percent cost overrun for the Canadian segment into the NNEB calculations. Table II-3 demonstrates the effect of even larger cost overruns for this segment. Note that Canadian actions leading to a 100 percent cost overrun would decrease the base case NNEB by approximately $1.3 billion, to $13.6 billion.

Combined Effects: The High Cost Scenario. Of course, major construction cost overruns may occur on both the Canadian and Alaskan segments of the ANGTS. The causes of such overruns could be either related or independent. Rather than continue to probe the implications of cost overruns for each segment separately throughout this report, this analysis examines one "high cost" scenario to understand the effects of catastrophic construction cost overruns.

This high cost case is based on earlier work by the Departments of the Interior and Transportation, which estimated the "worst case" cost experience

38/ Recommendation to The President, p. I-45.

for the three ANGTS proposals.[39] The Task Force assessed the worst case scenario through the use of expert judgment on specific cost and schedule items for each proposed system. The worst case was then defined as the cost estimate located three standard derivations from the expected overrun; that is, the task force judged with almost 99.9 percent confidence that actual costs would not exceed the worst case amount.

This analysis adopts the earlier worst case analysis by applying a ratio, consisting of the worst case costs and expected costs, to the base case (expected) cost estimates employed in the President's Decision (adjusted to mid-1979 dollars),[40] where:

$$\frac{\text{worst case cost}}{\text{expected cost}} = 1.466$$ [41]

Next, lower-48 construction cost was assumed to equal expected levels; then, the overrun amount (in mid-1979 dollars) was allocated equally between the Alaskan and Canadian segments.[42] This allocation results in an overrun of

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39/ U.S. Department of the Interior, U.S. Department of Transportation, Alaska Natural Gas Transportation Systems: White House Task Force Lead Agency Report on Construction Delay and Cost Overruns, July 1, 1977, (hereafter called the Cost Overrun Task Force Report).

40/ Both the President's Decision and the Cost Overrun Task Force Report expect overall construction cost overruns of about 30 percent over filed cost estimates.

41/ Cost Overrun Task Force Report, p. 131.

42/ This rough allocation scheme is used in lieu of detailed quantitative data on the Cost Overrun Task Force Report's conclusions about where the overruns would occur. We believe it is a reasonable approach since the Alaskan segment involves greater technological and other uncertainties but the Canadian segment is larger in an absolute dollar sense.

approximately 137 percent over filed costs for the Alaskan segment and of approximately 108 percent for the Canadian segment. For this worst case of combined overruns, the NNEB estimate again remains significantly positive a $10.4 billion.

Project Delays

Delays of the ANGTS project could generate new problems or new opportunities for project supporters. Among the possible consequences, a delay could affect the quantity of gas available for shipment, the quantity of Alaskan gas demanded by consumers, the interest of potential lenders and equity investors in the project, or the value of the gas deliveries to the nation. These potential results are all important; however, all but the last effect are beyond the scope of this analysis.

If the project makes sense now, that is if its base case NNEB estimate is positive, then with other things equal, the sooner the project is undertaken the better off the nation would be. Because of society's time preference, a delay in starting the project would cause the NNEB to decline exponentially as a function of the length of time the project is postponed if the real value of all benefits and costs over the project's life were to remain constant and the NNEB were measured from the perspective of the NNEB's present value in mid-1979. For the base case, however, the gas value increases over time. With this assumption, a one-year delay prior to any ANGTS expenditures would reduce the base case estimated NNEB by $0.4 billion (mid-1979 dollars).[43/]

After some or all construction has been completed, project delay would lead to even greater decreases in NNEB. Not only would the net benefits be postponed but construction costs already would have been incurred. A one-year delay after the completion of the system's construction and prior to the delivery of any gas would generate greater adverse effects for the NNEB estimate than for any delay of the same length at any other point in the project life. Such a delay would reduce the estimated NNEB by $ 0.4 billion (mid-1979 dollars).

EFFECTS ON THE WORLD OIL PRICE

Our base case NNEB estimates include the direct economic efficiency benefits of substituting Alaskan gas for oil consumption but ignore any other significant effects of reducing U.S. oil use. The delivery of Alaskan natural gas to lower-48 energy markets, especially to distillate fuel oil users, would reduce U.S. oil imports. Decreased U.S. oil imports could reduce worldwide oil demand sufficiently to generate downward pressure on world oil prices.

Currently, a clear consensus does not exist concerning the reduction of world oil prices at all future points in time that would result from, say, a reduction in U.S. oil imports of 1 million barrels per day at all future points in time. In fact, DOE has considered estimates which range from $.10

43/ It appears that a one year delay, compared to the start date used throughout th[illegible] ysis, is likely. See "U.S. delays threaten Alaskan gas line," Oi[illegible] as Journal, February 26, 1979, p. 50. We return to this delay issue in Section IV.

to $.70 per barrel for an import reduction of this magnitude.[44/]

Alaskan gas deliveries could replace approximately 430,000 barrels per day of oil imports over the project's life.[45/] Using the low end of the range of estimated world oil price effects ($.10 per barrel) and ignoring the off-setting effect on the gas value stemming from lower world oil prices, the ANGTS might easily produce annual savings of real resources, otherwise consumed by paymen s for oil imports, of $219 million (mid-1979 dollars) on a base of 6 million barrels of total annual oil imports.[46/] In turn, this would increase our base case NNEB estimate by $2.2 billion over a 25-year period. Importantly, higher estimates of the effect on world oil prices of cutting U.S. imports by 1 million barrels per day would increase this NNEB estimate approximately linearly.

ZERO BENEFITS SCENARIO

Given the high values of the NNEB estimates, it may be useful to explore the magnitude of ANGTS cost overruns that could negate the economic benefits from the delivery of Alaskan gas.[47/] Assume, (i) since the construction of

44/ The estimate at the low end of the range is based on analyses using an ICF world energy model described in ICF Incorporated, Imperfect Competition in the International Energy Market: A Computerized Nash-Cournot Model, May 1979.

45/ Based on 910 x 10^{12} Btus of net gas delivered per year and 5.825 million Btu per barrel of distillate oil (ignoring refinery Btu losses in the case where crude oil, rather than distillate would be imported).

46/ Approximately the level for 1995 in the Energy Information Administration's ARC, 1979, Series C.

47/ Gas production and gas conditioning cost overruns would also lower the NNEB estimates, but the cost behavior of such non-ANGTS elements are beyond the scope of this analysis. We believe, however, that simply their small absolute size in the base case, compared to the ANGTS construction cost, makes them less critical from the standpoint of NNEB.

the Northern Border Pipeline and Western Leg segments is relatively straightforward, that their actual costs are as expected and (ii) that the Canadian segments are constructed for the worst case costs incorporated in the high cost scenario. Still, the Alaskan segment would have to experience an overrun of more than 400 percent over filed costs before the NNEB would fall to zero.

The TAPS experience certainly demonstrated that such overruns are not inconceivable for arctic pipeline construction projects. Nevertheless, only a similar catastrophic overrun, combined with other conservative features on the benefits side of the base case NNEB estimate, would make the ANGTS project economically inefficient from a national perspective.

These sensitivity analyses strongly suggest that, from the standpoint of the efficient use of the nation's economic resources, the Alaskan project appears highly desirable. Positive net national benefits for the project, however, do not mean that all the individual participants in the project share equally in these net benefits. This natural gas pipeline project must proceed in a regulated environment, and the regulations can affect the distribution of the net economic benefits among the participants in important ways. Moreover, the distribution of benefits could affect the likelihood of project implementation. The next section examines the regulated prices that consumers would face for Alaskan gas, and the succeeding sections explore the market position of delivered Alaskan gas and the distribution of project benefits among consumers, the ANGTS consortium members, and others.

III. DELIVERED COST OF ALASKAN GAS

The cost of delivering Alaskan gas at the citygate of lower-48 gas distribution utilities has four important components:

- the wellhead gas price
- state severance taxes on gas production
- any additional charges for gas conditioning
- the cost of service to transport the gas from Prudhoe Bay to the citygate.

This analysis uses the annuity-equivalent of the annual sum of these figures over 25 years of pipeline operations as its primary tool for assessing the attractiveness of Alaskan gas to potential customers. The strengths and weaknesses of this approach should emerge from discussions later in this section.

The wellhead gas price is one of the two most important factors in determining the cost of delivered Alaskan gas. Section 109 of the Natural Gas Policy Act of 1978 (NGPA) established a ceiling wellhead price of $1.45 per million Btu as of April 1977, plus inflation adjustments, for natural gas produced from the Prudhoe Bay unit and transported through the ANGTS.[1/] Although this amount was established as a maximum, it is generally considered to be the most likely price.[2/]

1/ The inflation adjustments are based on $1.45 effective April 20, 1977.

2/ This presumably reflects the effects of rolled-in pricing and/or the degree of competition at the field market for Alaskan gas. Analysis of this expectation and its policy implications is beyond the scope of this analysis.

The state of Alaska would impose a severance tax on Prudhoe Bay gas production equal to approximately 10 percent of the wellhead price. This would add approximately 15 cents to the wellhead ceiling price of $1.45 per million Btu in April 1977 terms.

A gas conditioning cost estimate of 35 cents has been used in the FPC's Recommendation, the President's Decision, and other government documents.[3/] A recently proposed FERC rule would require that all of these gas conditioning costs be recovered within the maximum price that gas producers may charge for their gas (i.e., $1.45 per million Btu, adjusted for inflation).[4/] Unless stated otherwise, this analysis assumes that the conditioning costs are covered within the producers' maximum lawful price; therefore, estimates of the delivered cost of gas include no additional conditioning charges.

The cost of service for transporting the gas through the ANGTS is the other important component of the delivered cost of Alaskan gas. This cost, however, is derived in a way that is significantly different from the other components. The three previous cost factors are expected to be relatively stable during the project's operating period. Calculated on a similarly stable basis, the annuity-equivalent cost of service is approximately the same size as the wellhead gas price.

3/ For example, see FERC, "Notice of Proposed Rulemaking and Statement of Policy," Treatment of Certain Production Related Costs, For Natural Gas to be Sold and Transported Through the Alaskan Natural Gas Transportation System, Docket No. RM79-19, February 2, 1979, p. 9, adjusted from 1975 to 1978 dollars.

4/ Ibid.

In contrast, the traditional historical embedded cost method of establishing the cost of service yields high costs in a project's early years and decreasing costs over time as the rate base is depreciated. From the first year of operation to the time when the rate base is fully depreciated, the difference in the cost of service can be large.5/ The implications of the these time patterns of transportation cost are discussed in detail in our analysis of Alaskan gas marketability (see Section IV).

For our base case assumptions, the delivered cost of Alaskan gas consists of the following components:

	Annuity-Equivalent 6/ (mid-1979 dollars)
Wellhead Price of Gas	$1.68 per mmBtu
Severance Tax	0.17
Gas Conditioning Charge	.00
Pipeline Cost of Service	1.33
Delivered Cost of Gas	3.18

SENSITIVITY ANALYSIS

The delivered cost of Alaskan gas could change for many of the same reasons as the NNEB estimates. Variations of several of the inputs to the cost calculations are considered here, including:

5/ Under the base case assumptions, the pipeline cost of service would vary from $2.34 per million Btu in the first year to $0.43 per million Btu in the twenty-fifth year (mid-1979 dollars).

6/ Assuming a six percent discount rate and a 25-year project life.

- Construction costs
- Gas flow rates
- Length of project life
- Canadian energy decisions

In addition to these potential changes, which reside largely beyond the direct control of the federal regulatory process, two other variations are also considered, changes in allowed wellhead prices and reallocation of gas conditioning costs.

Construction Cost Changes

The potential for cost overruns and possible reasons for such problems have already been discussed in the NNEB sensitivity analysis (see Section II). Here we explore the implications of analogous events for the gas prices that consumers would face.

The first section of Table III-1 illustrates how changes in the expected costs of constructing the Alaskan leg of the pipeline system would affect delivered gas costs. In percentage terms, the delivered gas cost is not particularly sensitive to the costs of building the Alaskan segment. For example, if the Alaskan line were built for the costs filed by the ANGTS consortium, rather than for the 30 percent overrun assumed in the President's Decision, the delivered cost would decrease by 2 percent. On the other hand, if the Alaskan construction cost were twice as much as originally anticipated, the delivered cost would increase 5 percent above the base case. A disastrous 400 percent overrun on the Alaskan segment (i.e., 5 times the filed estimates) would increase the delivered gas cost by 25 percent.

At first glance, the insensitivity of the delivered gas cost to Alaskan segment overruns might appear surprising. But transportation costs represent only about 40 percent of delivered gas costs, and Alaskan segment costs are less than 40 percent of transportation costs for the base case. Consequently, this insensitivity should be expected.

The second section of Table III-1 explores how construction cost changes for the Canadian segment would affect the delivered cost of gas. Again, the sensitivity of delivered costs to construction costs for this part of the pipeline is not large. For example, if the line were built for its filed cost, rather than the 40 percent overrun assumed in the President's Decision, the delivered cost would decrease by 3 percent. If the Canadian segment, for which there should be relatively little technological uncertainty, were to double in cost from the filed estimates, the delivered cost would increase 4 percent from the base case. And even the "high cost" scenario described in the previous section (132 percent overrun for the Alaskan segment and 105 percent overrun for the Canadian segments), would yield a delivered gas cost only about 12 percent higher than the base case.

Gas Flow Rate Changes

Changes in the rate at which Alaskan gas flows through the ANGTS would also affect the cost of delivered gas. The net result stems from two effects, each moving in opposite directions. First, the flow of additional gas would spread common costs over a greater pool of gas supplies, thereby lowering unit costs. Second, a greater flow would require increased capital expenditures for compression capacity and increased fuel expenditures for each unit of gas

TABLE III-1

DELIVERED GAS COST ESTIMATES
FOR SELECTED CONSTRUCTION COST SCENARIOS a/
(mid-1979 dollars)

Cost Scenario	Delivered Gas Costs b/ ($/mmBtu)	Changed From Base Case (percent)
ALASKAN OVERRUN		
0% (filed costs)	$3.12	- 2 %
30% (base case)	3.18	--
100%	3.33	+ 5
200%	3.54	+11
400%	3.97	+25
CANADIAN OVERRUN		
0% (filed costs)	3.09	- 3
40% (base case)	3.18	--
100%	3.32	+ 4
COMBINED CHANGES		
filed costs, all segments	3.01	- 5
expected costs, all segments	3.18	--
"high cost" scenario c/	3.55	+12

a/ Base case assumptions used for other parameters.

b/ 25-year annuity-equivalent, at the citygate.

c/ Assumes a 132 percent Alaskan overrun and a 105 percent Canadian overrun (derived from DOI/DOT worst case analysis). U.S. Department of the Interior, U.S. Department of Transportation, Alaska Natural Gas Transportation System White House Task Force Lead Agency Report on Construction Delay and Cost Overruns, July 1, 1977.

delivered.[7/] Of course, a lower flow rate would have opposite effects.

Table III-2, below, presents the delivered cost estimates of Alaskan gas resulting from changes in the rates at which gas would flow through ANGTS.

TABLE III-2

EFFECTS OF GAS FLOW RATE CHANGES
ON COST OF DELIVERED GAS [a/]
(mid-1979 dollars)

Gas Flow Rate (Bcf/day)	Delivered Gas Cost [b/] ($/mmBtu)	Change in Gas Cost From Base Case (percent)
2.0	$3.37	+6%
2.4	3.18	—
3.2	3.05	-4
4.0	3.09	-3
4.8	3.25	+2

a/ Base case assumptions used for other parameters.

b/ 25 year annuity equivalent, at the citygate.

If the flow rate were increased by one-third to 3.2 Bcf/day, the delivered cost of the gas would decrease by 4 percent to $3.05 per million Btu. A flow rate of 4.0 Bcf/ day would lower the delivered cost to $3.09 per million Btu, a level lower than the base case but higher than the 3.2 Bcf/day case. Given the current system design, this increase indicates that fuel use penalties would outweigh the capital cost economies of scale at an input flow rate equal

7/ If a flow rate higher than 2.4 Bcf/day were anticipated prior to system design, a system with lower unit costs could possibly be engineered. This analysis, however assumes that any flow rate changes are accommodated by changes in the system as now planned.

to or greater than 4.0 Bcf/day. If gas production rates were lower than expected, unit costs could increase to $3.37 per million Btu, or a 6 percent increase, for a 2.0 Bcf/day flow rate.[8/]

Project Life Changes

The base case delivered cost of Alaskan gas assumes a 25-year delivery period in order to develop the annuity-equivalent cost estimate. In the ANGTA, Congress expressed an interest in these cost estimates for a 20-year period.[9/] For a minimum likely useful project lifetime of 20 years, the delivered unit cost of gas would increase to $3.28 per million Btu. For 30 and 50 years, a first approximation of the delivered gas cost indicates decreases to $3.11 and $2.98 per million Btu, respectively.[10/] These figures are summarized in Table III-3.

Canadian Energy Actions

Two Canadian energy supply decisions could also affect the delivered cost of Alaskan gas. These two possible actions are (i) a reversal of the decision to move Mackenzie Delta gas through the ANGTS and (ii) early sales of Alberta gas through pre-built southern portions of the ANGTS.

8/ The fuel consumption behavior is extrapolated from data in FERC staff, Alaska Gas Project Office, System Design Inquiry draft paper, undated.

9/ ANGTA, Section 5(c).

10/ This approximation assumes no new capital expenditures are required to maintain the ANGTS for these longer periods.

TABLE III-3

DELIVERED GAS COST AS A FUNCTION OF LENGTH OF RELEVANT TIME PERIOD a/
(mid-1979 dollars)

Length of Time	Delivered Gas Cost a/ ($/mmBtu)	Change in Gas Cost From Base Case (percent)
20 years	$3.28	+3%
25 years	3.18	—
30 years	3.11	-2
50 years	2.98	-6

a/ Base case assumptions used for other parameters.

b/ 25-year annuity-equivalent, at the citygate.

Removing the requirement to ship Mackenzie Delta gas would eliminate the U.S. share of the cost of the Dempster Lateral, which would connect the Mackenzie Delta gas to the ANGTS. Conversely, this would also increase the U.S. share of the costs for the ANGTS Canadian segments. The combination of these countervailing effects is estimated to be an increase of 2 percent in the base case delivered gas costs, from $3.18 to $3.23 per million Btu.

The early delivery of Alberta "bubble" gas through pre-building of the southern portions of ANGTS would allow some of the pipeline's capital expenditures to be depreciated prior to initial deliveries of Alaskan gas. A precise estimate of how early deliveries would affect the figures for the delivered cost of gas is beyond the scope of this analysis.

Policy Actions

The FERC has proposed that "the Prudhoe Bay producers should be responsible for the construction and operation of the required conditioning facility."[11/] This analysis assumes that the maximum lawful price ($1.45 per million Btu, with adjustments) includes the payment of gas conditioning costs.

Alternatively, the Commission could decide to make gas consumers bear all or part of the gas conditioning costs. If the ANGTS consortium were required to provide gas conditioning facilities as a part of the pipeline system, the delivered cost of gas would increase by approximately 22 percent to $3.88 per million Btu (1979 dollars) under our base case assumptions.[12/]

Another regulatory issue concerns the maximum lawful price for Prudhoe Bay gas set by the NGPA (Section 109). On a present value basis at this price, the wellhead revenues would exceed estimated production costs (including royalty and severance taxes and a normal return on investment) and gas conditioning costs by $12.9 billion (mid-1979 dollars). Although Commission discretion in this area may be limited, reduction of these wellhead revenues could enhance Alaskan gas marketability and the welfare of gas consumers considerably, but only at the expense of Alaska and federal taxpayers and the gas producers.

11/ FERC, "Notice of Proposed Rulemaking and Statement of Policy," Treatment of Certain Production-Related Costs for Natural Gas to be Sold and Transported Through the Alaska Natural Gas Transportation System, Docket No. RM79-19, February 2, 1979, p. 12.

12/ See Appendix C. This $0.70 (1979 dollar) gas conditioning charge is roughly equivalent to the $0.60 charge mentioned in Foster Associates, Inc., "The Marketability of Prudhoe Bay Gas In The Lower 48 States," March 28, 1979, p. 1. Both the Foster Associates estimate and this analysis use Ralph M. Parson Co. data. The differences from the earlier estimate of $0.30 (1975 dollars) mentioned in the President's Decision, p. 95, can largely be explained through the charging of the maximum wellhead price for the gas consumed in the conditioning process rather than counting just the actual production costs for the gas used in conditioning.

GAS COST BEHAVIOR OVER TIME

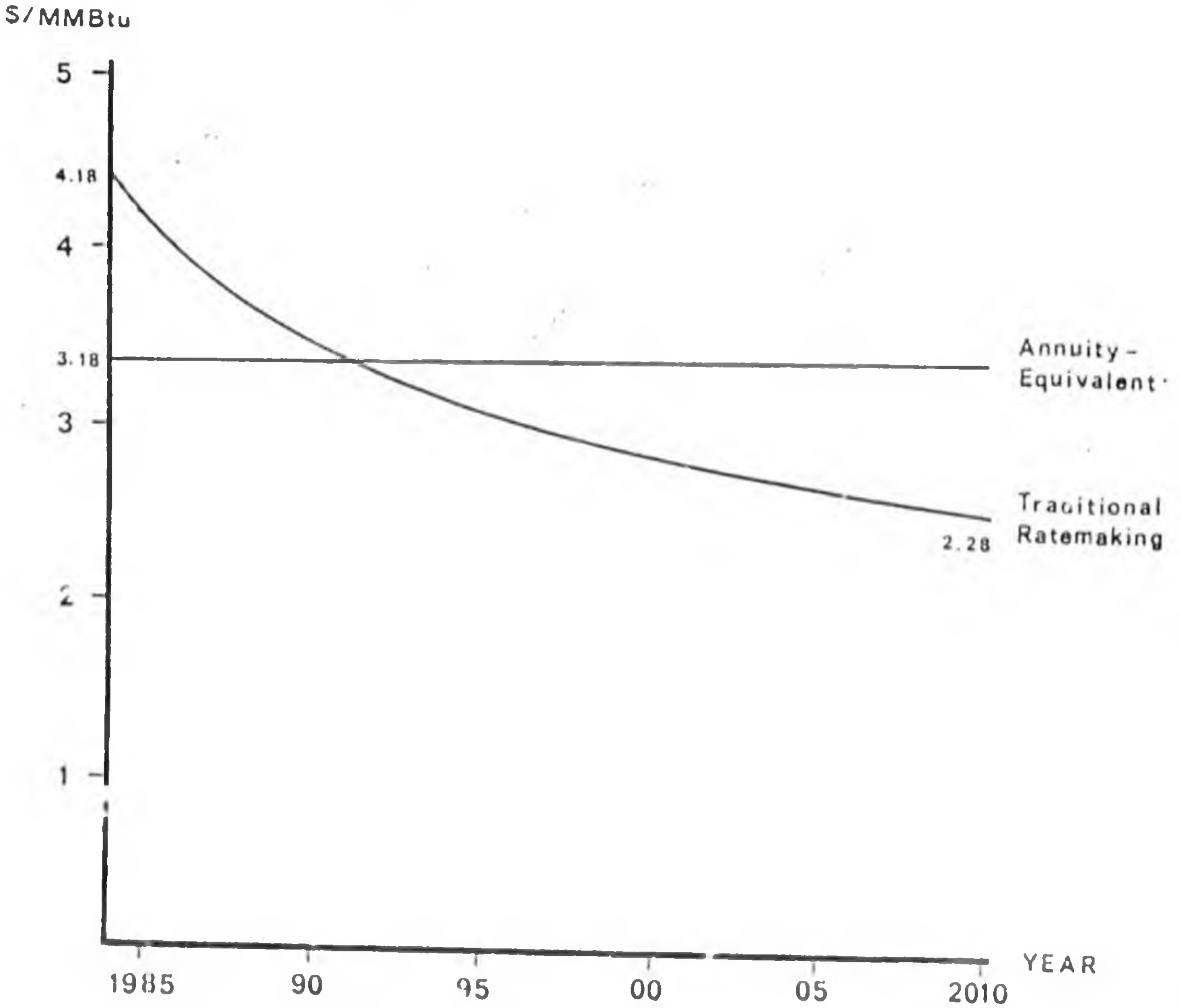
Thus far, our discussion of the delivered costs of Alaskan gas has focus on the annuity-equivalent cost. If, however, FERC were to apply the traditional historical embedded cost approach to the ANGTS ratemaking, the actual costs facing potential Alaskan gas purchasers would vary from year to year.[13/] Under traditional ratemaking, the pipeline cost of service includes a constant rate of return on the rate base, where the rate base is defined by the undepreciated book value of the pipeline investment. On this basis, the rate base is highest in the first year of service and, then, gradually decreases over time until the rate base is fully depreciated. Figure III-1 illustrates how the time-profile of the cost of service affects the yearly delivered cost of Alaska gas (in mid-1979 dollars).

The time pattern under traditional cost of service regulation yields costs which initially are much higher than the annuity-equivalent cost and decrease steadily to a level equal to O&M costs and other annual expenditures, well below the annuity-equivalent cost. In principle, this artifact of traditional regulatory practice represents only one of several possible ANGTS cost profiles. One alternative would be a constant cost (in real or nominal dollars) equal to an annuity-equivalent value. It would also be possible to devise a gas rate schedule of equal present value that allowed lower costs in the

13/ The present value of the stream of these actual costs, however, would be equal to the present value of the annuity-equivalent cost.

FIGURE III-1

DELIVERED ALASKAN GAS COSTS
TRADITIONAL REGULATION VS. ANNUITY-EQUIVALENT



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earlier years of the project and increased costs over time.[14/]

The importance of the annuity-equivalent gas costs and the time pattern traditional gas pipeline tariffs results from the opposite price signals each can transmit to gas customers. Earlier, Section II demonstrated the robust nature of the ANGTS NNEB estimates, which remain positive for any reasonable expectations for the project. But regardless of the magnitude of the potential national benefits of the Alaskan gas pipeline project, the proposed project must be implemented in order to realize these benefits. As mentioned in our introduction, the project can be completed only if its sponsors, other equity investors and lenders believe that the Alaskan gas delivered through the pipeline can be sold. This section has explored the range of annuitized costs which gas consumers would be required to pay if the project were implemented. In the next section, we begin to explore the market outlook for Alaskan gas.

14/ Although the former Interstate Commerce Commission approach has no unique methodological value, this pattern could be developed through the ratemaking method used for oil pipelines, which allows a constant rate of return on a rate base defined by the replacement cost of the line. Alternatively, the depreciation schedule could be altered so that the resulting rates display less variation on a real cost basis than do gas rates based on traditional depreciation treatment.

IV. THE RELATION OF THE ANGTS TO THE U.S. ENERGY MARKET

The U.S. natural gas outlook differs radically from the situation perceived at the time the Alaskan Natural Gas Transportation Act of 1976 (ANGTA) was enacted. Then, Congress found that "a natural gas supply shortage exists in the contiguous States of the United States."[1/] The current outlook appears to be much improved because of legislated changes in natural gas wellhead pricing, end use pricing requirements and reforms, user energy conservation, and other factors. Also, large quantities of Mexican gas have been offered for sale to the U.S., and additional Canadian gas supplies may be offered for export.

In this updated context, this section analyzes whether (i) Alaskan gas can offer economic advantages as a substitute for distillate fuel oil, (ii) the Alaskan gas pipeline project compares favorably with another major potential new gas project--Mexican gas, and (iii) the project's benefits to the nation and to consumers remain if Alaskan gas replaces residual fuel oil rather than distillate.

BASIS FOR COMPARISON

As noted several times in earlier sections, the traditional gas pipeline cost-of-service ratemaking methods can provide misleading signals about the fundamental economic merits of a capital intensive gas supply project such as the ANGTS. For example, consider a comparison of first-year costs between a

1/ ANGTA, Section 2.

capital intensive gas project and an alternative gas project with low capital investment but with real cost growth built into the price term (e.g., a source whose price of gas, ex transportation, is tied by formula to a rapidly escalating world oil price). The first-year costs of the capital intensive project would include a return on the entire, undepreciated rate base. In contrast, the first-year costs for the latter project would precede the onset of any real cost growth caused by future world oil price increases. Thus, the worst year of the capital intensive project would be compared to the best year of the low investment project. A comparison of the last-year or average-year costs could be similarly inappropriate in an economic sense, even if it were to reverse the apparent relative attractiveness of the two alternatives.

Although one-year cost comparisons have appeared in analyses of the ANGTS,[2/] a more commonly used measure has been the simple arithmetic average of the annual costs. Since the arithmetic average may introduce only minor distortions when comparing projects with similar cost patterns over time, its use as a shortcut in comparing the ANGTS to other capital intensive alternatives may have been acceptable. But for comparing the ANGTS with other less capital intensive energy supply options (e.g., distillate fuel oil or Mexican gas), it is important to use a comparison technique that carefully incorporates the time value of money (Appendix E presents detailed examples of problems associated with the use of an arithmetic average).

2/ For instance, see Congressional Research Service, "Mexico's Oil and Gas Policy: An Analysis," prepared for the Committee on Foreign Relations, U.S. Senate and the Joint Economic Committee, December 1978, pp. 5, 48-49.

To account for the time value of money, this analysis calculates the equivalent cost of purchasing one unit (a million Btus) of energy if the price were the same (in real terms) in each year of the time period considered.[3/] In a manner consistent with lifecycle cost comparisons, these annuity-equivalent costs (or "levelized" costs) provide a basis for comparison among energy supply alternatives with radically different cost patterns over time. This concept was employed to develop the annuity-equivalent figures used in Section III. The following analyses of Alaskan gas versus other potential gas supplies and other energy sources use both annuity-equivalent values and annual time profiles to explore the market prospects for Alaskan gas.

ALASKAN GAS AND DISTILLATE FUEL OIL

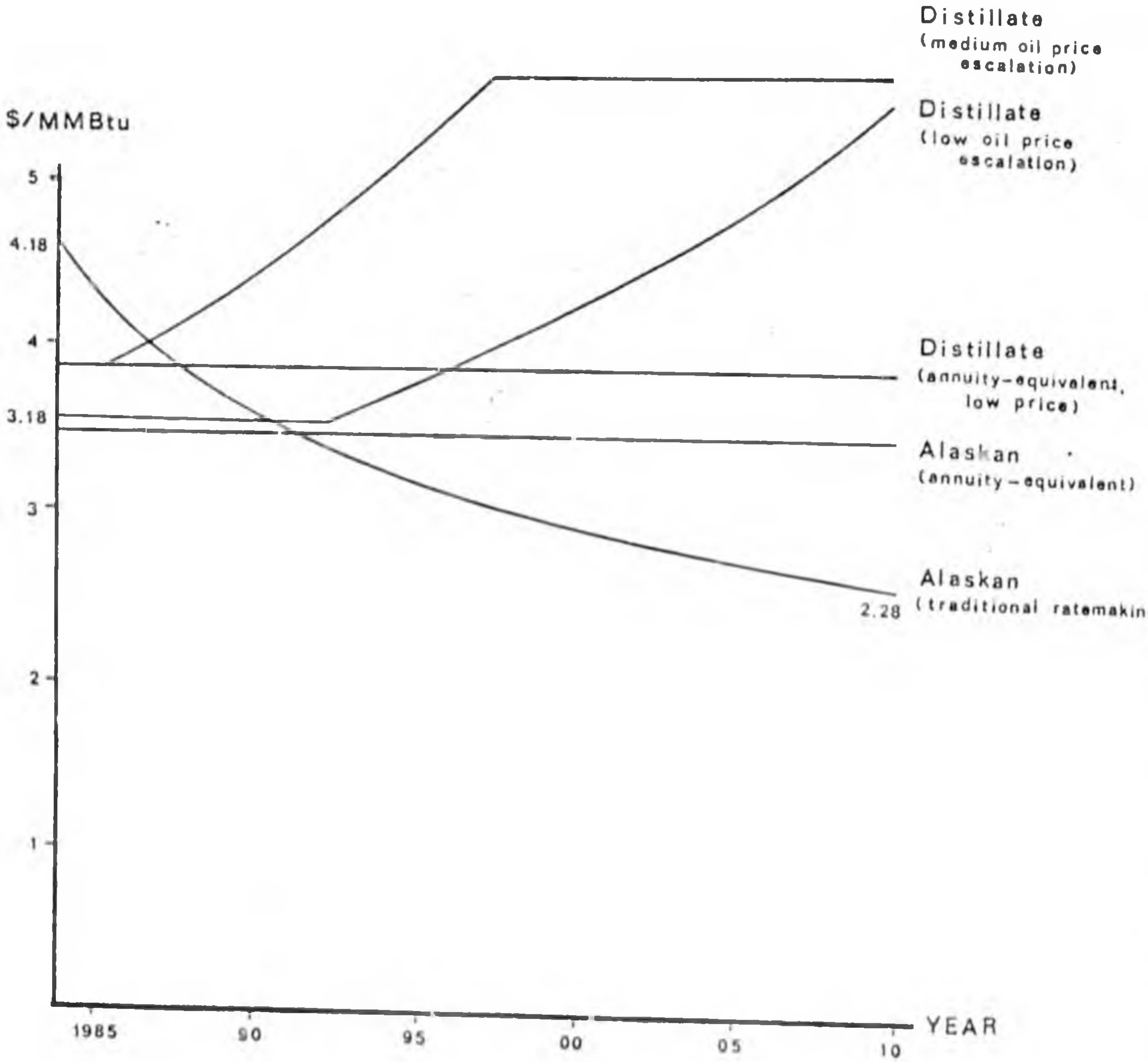
The NNEB analysis (Section II) found that, from a national perspective, the United States would gain large net benefits from the delivery of Alaskan natural gas. Under the base case assumptions, this benefit would be approximately $14.9 billion (mid-1979 dollars).

Despite advantages to the nation from implementing the ANGTS, the base case estimates indicate that potential Alaskan gas customers, if faced directly with the cost of Alaskan gas through a separate rate schedule, initially might prefer distillate fuel oil. This paradox stems from traditional cost of service ratemaking methods, under which customers for Prudhoe Bay gas could expect Alaskan gas costs well above distillate fuel oil costs in the early years of delivery (see Figure IV-1).

3/ See Appendix E for an expanded discussion of the annuity-equivalent concept.

FIGURE IV-1

ALASKAN GAS AND DISTILLATE FUEL COST PROJECTIONS
(1979 dollars)



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

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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)

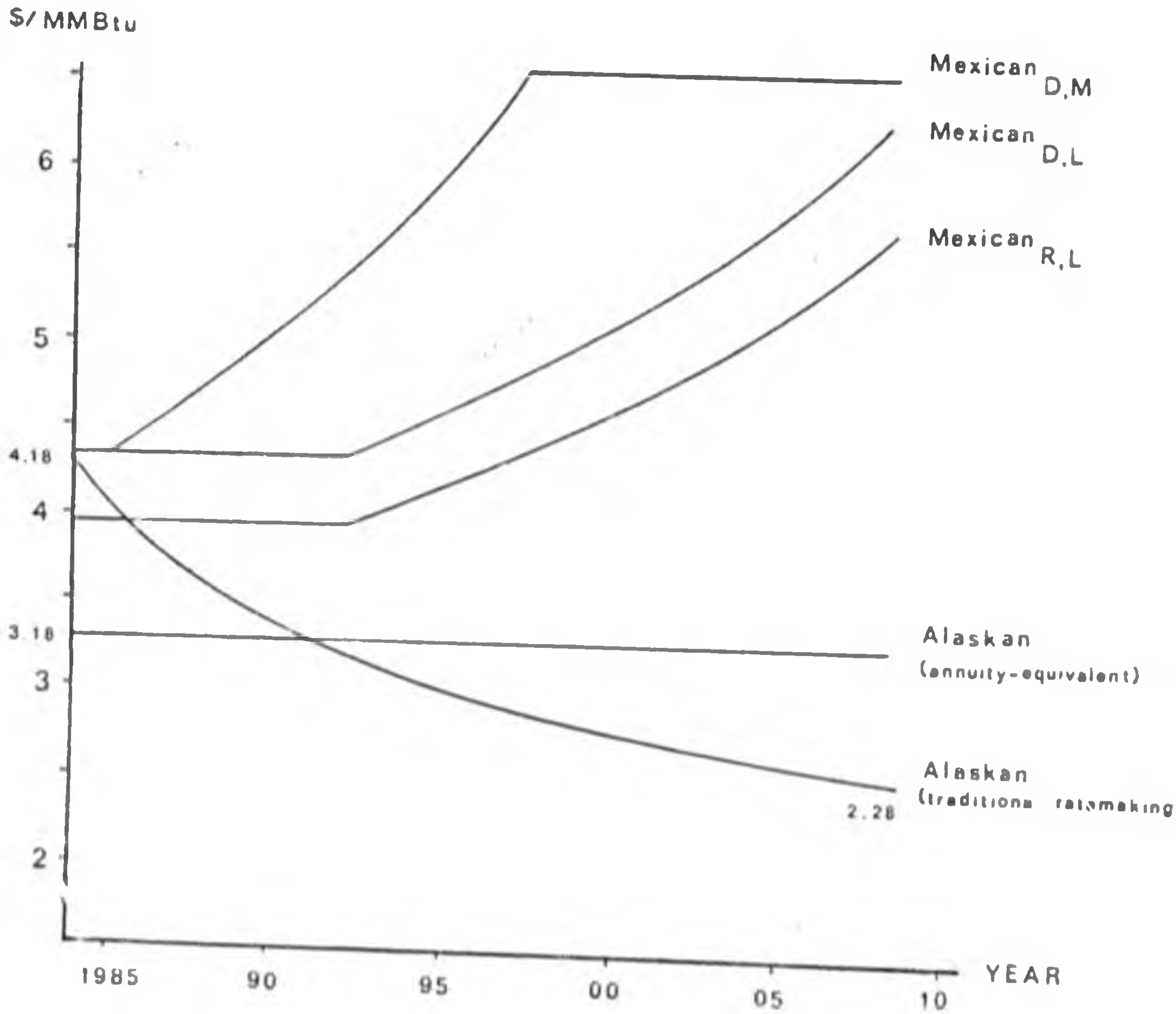

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TABLE IV-1

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)	Total Lifecycle Costs[a/] (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 proceed 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 accrue 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).

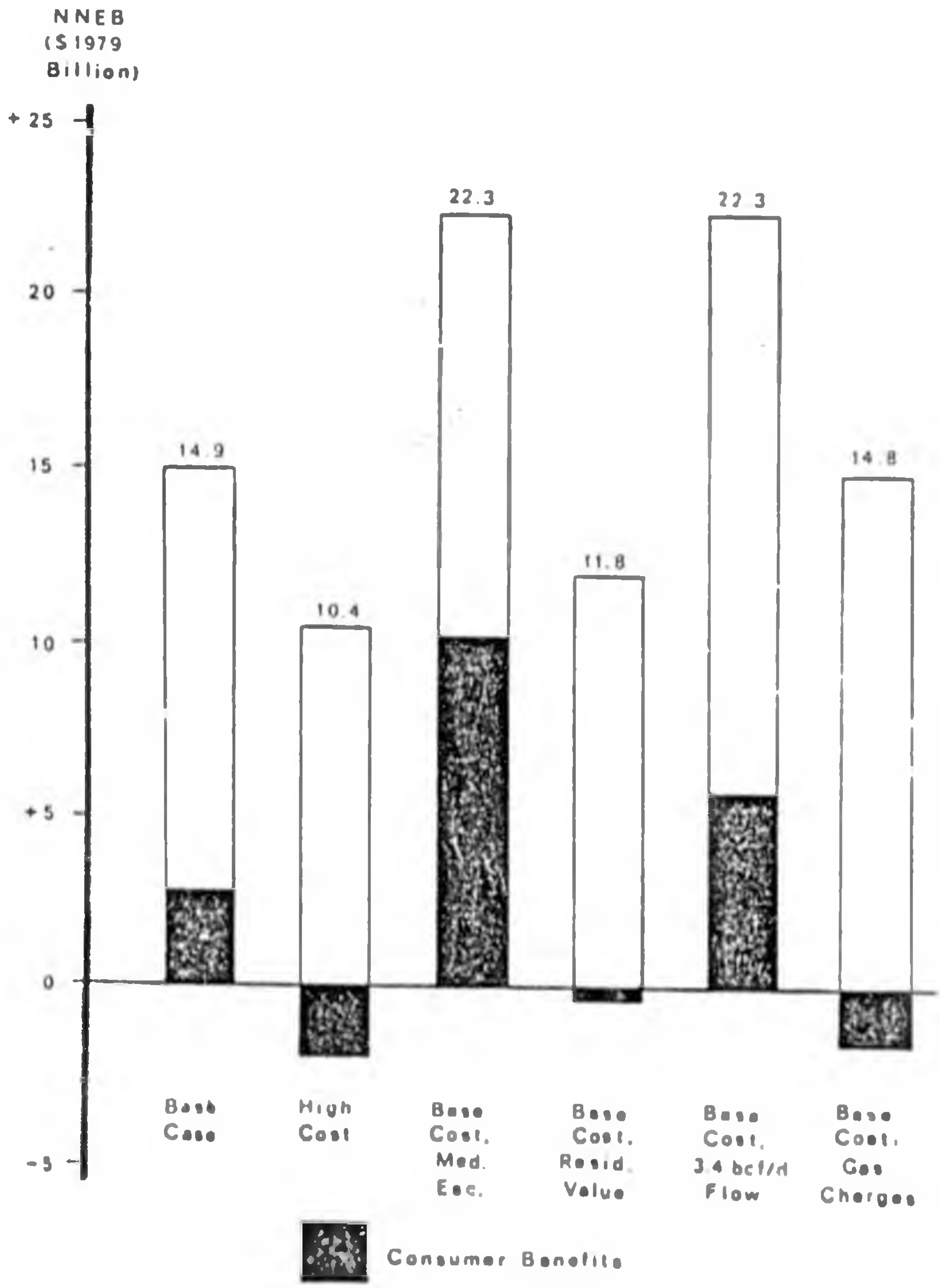
TABLE V-1

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)



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

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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], Transporting Natural Gas from the Arctic, pp. [illegible].

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.

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	3.1d	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 Alask 1 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 <u>if</u> 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, <u>if</u> 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.