

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

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surface geology and expoloratory drilling have been carried out along the south-east margin onshore. Some of the holes contained minor oil shows. The basin, located on the north side of the Alaska Peninsula, covers an area of about 46,000 square miles, and is one of the largest Tertiary basins around the Pacific rim. Marine seismic data indicate that the Bristol Bay basin contains a very thick section of gently folded, Tertiary marine and non-marine clastic and volcanic rocks. Several structural highs are located at the margins of the basin and offer good potential for hydrocarbon accumulations. 20/ The Cenozoic rocks which appear to offer the best reservoir potential are Miocene sandstones.

The offshore portion of the basin lies under rather shallow water, 50 to about 400 feet, at the southern extremity of the Bering Sea ice. A Continental Offshore Stratigraphic Test (COST) well is planned for the basin in August 1982. 21/ Two Federal lease sales are scheduled for the area, one in April 1983 and the second in April 1985. The U.S. Geological Survey recently estimated that from 0 to 5.6 tcf of recoverable natural gas may exist in the Bristol Bay basin offshore (with a statistical mean of 1 tcf). Estimates for the onshore parts of the basin range from 0 to 2.3 tcf (with a statistical mean of 0.5 tcf). 22/

E. ST. GEORGE'S BASIN

The St. George basin is located on the Bering Sea continental shelf between the Pribilof Islands and the Alaska Peninsula. Lying under 300 to 500 feet of

20/ Hanley, Peter T., and William W. Wade. Bering Basins Show Good Potential. Offshore, April 1981. p. 127.

21/ Offshore West Alaska Basins Are Hot Prospects. Oil and Gas Journal, April 13, 1981. p. 91.

22/ Dolton, G. L., et al., op. cit., p. 8, 11.

water, the basin, as defined by seismic surveys, is an elongate Tertiary sedimentary depression, caused by a northwest-trending structural graben 23/ about 200 miles long and 20 to 30 miles wide, which is filled with more than 30,000 feet of essentially unfolded Eocene to Recent sediments. 24/ The rocks that appear to have the greatest reservoir potential are Miocene sandstone units, while the best source rocks appear to be Eocene and Oligocene shales which occur deep in the graben. Hydrocarbon traps which may occur include basement highs on the margins and within the deep graben and fault closures against the steep basin walls. 25/

A COST stratigraphic hole has been drilled in the St. George basin and a second is planned. Three Federal lease sales are scheduled (February 1983, December 1984, and December 1986). The U.S. Geological Survey estimates that the basin may contain from 0 to 10.7 tcf of undiscovered recoverable natural gas, with a statistical mean of 2.3 tcf. 26/

F. NAVARIN BASIN

The Navarin basin is the largest of the Bering Sea basins (300 miles long by 160 miles wide). It is located between the Pribilof Islands and Cape Navarin in the Soviet Union. The northwestern part of the basin lies within Soviet territory, but the exact boundary has not been resolved. The basin is a

23/ An elongate, depressed crustal unit, bounded by faults on its long sides.

24/ Hanley, Peter T, and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 121.

25/ Ibid., p. 124.

26/ Dolton, G. L., et al., op. cit. p. 8.

graben produced by tensional faulting along the continental margin and is filled with 35,000 feet of interbedded sandstone and shale of probable marine origin, ranging in age from Eocene to Recent. 27/ Seismic surveys have indicated that the upper part of the Tertiary section (Miocene and Pliocene) contain potential sandstone reservoirs. Seismic reflection data also have revealed several hundred "bright spot" anomalies, which may be related to shallow gas deposits, and deeper "bright spots," which could correspond to deeper petroleum deposits. Possible traps include sediment drape over basement highs and fault closures within the basin. 28/

Favorable seismic indications and recent Soviet discoveries onshore in eastern Siberia have resulted in evaluations of the Navarin basin as the most prospective of the Bering Sea basins. However, operating conditions will be extremely difficult. Navarin basin drilling will be hundreds of miles from an operations base and must be done in the summer to avoid ice, but even in summer storms are violent. 29/ A COST stratigraphic well is planned for the basin in 1983. Federal lease sales are scheduled in March 1984 and March 1986. The U.S. Geological Survey estimated that undiscovered recoverable gas resources in the Navarin basin range from 0 to 24.9 tcf, with a statistical mean of 5.6 tcf. 30/

G. NORTON BASIN

The Norton basin is located between the Seward Peninsula and the Yukon delta. It consists of a series of west-northwest trending Late Cretaceous

27/ Hanley, Peter T., and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 127.

28/ Ibid.

29/ Offshore West Alaska Basins Are Hot Prospects, op. cit., p. 92, 96.

30/ Dolton, G. L., et al., op. cit., p. 8, 9.

normal faults which form downdropped grabens separated by uplifted horsts. 31/ The grabens contain the thickest sediment fill, up to 23,000 feet, while the sediment thickness over the horsts is generally thinner than 10,000 feet. The best reservoir potential is thought to be in Late Miocene and younger rocks. Potential traps are structural closures produced by sandstones draped over the horsts. 32/

Water depths in Norton Sound range from 25 to 150 feet. In the inner Sound, where water depths are 60 feet or less, artificial gravel islands would permit year-around drilling. In the deeper, open waters winter ice would limit drilling to the 4 to 6 month summer open water season.

A stratigraphic COST well has been drilled to 14,683 feet in Norton Sound. This well, along with geophysical surveys and onshore geological studies (which include data from shallow gas wells and gas seeps), provide the information for evaluations of the basin's petroleum potential. The U.S. Geological Survey recently estimated that the Norton Basin may contain from 0 to 5.5 tcf of undiscovered recoverable natural gas, with a statistical mean of 1 tcf. 33/ Federal lease sales are scheduled for November 1982, October 1984, and October 1986.

H. HOPE BASIN AND NORTH AND CENTRAL CHUKCHI SEA BASINS

The Hope basin is an offshore extension of the Selawik basin (beneath the Chukchi Sea) which has been tested by two wells drilled onshore near Kotzebue Sound. Since both wells were dry, the basin has been downgraded somewhat in

31/ An elongate, uplifted crustal unit, bounded by faults on its long sides.

32/ Henley, Peter T., and William W. Wade. Bering Basins Show Good Potential, op. cit., p. 121.

33/ Dolton, G. L., et al., op. cit., p. 8.

hydrocarbon potential. 34/ Seismic surveys indicate that the basin is moderately deep with large basement faults. It is thought to be filled with Late Cretaceous and Tertiary marine and non-marine clastic sediments. 35/

The U.S. Geological Survey's most recent estimate for undiscovered recoverable gas in the Hope basin ranges from 0 to 1.8 tcf, with a statistical mean of 0.3 tcf. The Survey noted, however, that the estimated quantities can be considered recoverable only if recovery technology permits their exploitation beneath Arctic pack ice. Such technology has not as yet been demonstrated. 36/ A Federal lease sale is scheduled for the Hope basin in July 1985.

North of the Hope basin, two deep Mesozoic basins underlie the Chukchi Sea. The North and Central Chukchi basins are divided by the Barrow arch, a subsurface structural ridge. The Central basin contains Mississippian-to-Jurassic sediments overlain by organic-rich Early Cretaceous shales, though to be similar to the source rocks of the Prudhoe Bay field. Coal containing younger Cretaceous strata occurs above the shales. North of the Barrow arch a thick sequence of bedded rocks thought to range from Cretaceous through Tertiary in age dip northward to the continental slope. Several large diapir folds 37/ occur in the sequence, some pierce the entire section up to the sea floor. 38/

34/ Wilson, Howard M. Alaska: Will It Ever Live Up to Its Potential? Oil and Gas Journal, Dec. 8, 1980. p. 38.

35/ Neel, T. H. Both Onshore and Offshore Alaska Hold Vast Exploration Potential. Oil and Gas Journal, June 27, 1977, p. 199.

36/ Dolton, G. L., et al., op. cit.

37/ A dome shaped fold, the overlying rocks of which have been ruptured by the squeezing out of the plastic core material (usually salt or shale).

38/ Riva, Joseph P., and James E. Mielke. Polar Energy Resources Potential. A Report Prepared for the Subcommittee on Energy Research, Development and Demonstration and the Subcommittee on Energy Research, Development and Demonstration (Fossil Fuels) of the House Committee on Science and Technology. U.S. Govt. Print. Off., Sept. 1976, p. 73.

The U.S. Geological Survey has estimated that from 0 to 22.6 tcf (with a statistical mean of 4.5 tcf) of undiscovered recoverable gas may exist beneath the North Chukchi Sea. The Survey estimate for the Central Chukchi is somewhat lower, 0 to 15.3 tcf (with a statistical mean of 3.0 tcf). ^{39/} However, the quantities projected can be considered recoverable only if the technology is developed that will allow production from beneath the Arctic ice pack, which exists in the Chukchi Sea. Such recovery technology is not yet in use. There are no Federal lease sales currently scheduled for either the North or the Central Chukchi basins.

I. ARCTIC SLOPE

The Arctic Slope, also called the North Slope, includes an area in excess of 100,000 square miles, a significant portion of which is considered to have hydrocarbon potential. Oil seeps along the Arctic coast have been reported since the early 1900s and in 1923 some 37,000 square miles of the North Slope were set aside as Naval Petroleum Reserve No. 4, an area currently undergoing Federal exploration for hydrocarbons. ^{40/} The onshore region includes the Arctic Coastal Plain, the Northern Foothills, the Southern Foothills and the Brooks Range.

The potential hydrocarbon area also extends offshore and includes the continental shelf of the United States under the Beaufort Sea. Water depths over much of this shelf are less than 200 feet. However, the western Beaufort Sea

^{39/} Dolton, G. L., et al., op. cit., p. 8, 9.

^{40/} Gryc, George. Summary of Potential Petroleum Resources of Region 1 (Alaska and Hawaii)—Alaska. Future Petroleum Provinces of the United States—Their Geology and Potential. Memoir 15, The American Association of Petroleum Geologists, Tulsa, Oklahoma, 1971. p. 62.

is almost completely covered by ice for about 9 months of the year and even during the nominal open season (mid-July to early October) scattered to solid pack ice is sometimes present. ^{41/} The winter ice canopy can be divided into three types: floating and bottom-fast ice of the inner shelf; a brecciated shear zone of grounded ice ridges, marking the area of interaction between the stationary fast ice and the moving polar pack; and the Arctic pack ice of new and multiyear floes, pressure ridges and ice-islands that are in almost constant motion. The general drift of the Beaufort pack ice is westerly. ^{42/}

The average thickness of the sedimentary rocks in the area exceeds 16,000 feet. A southward-thickening Mississippian-to-Jurassic sedimentary section extends between the Barrow arch, near the shoreline, and the Northern Foothills.

The Southern Foothills and the Brooks Range contain thrust plates of Paleozoic and Mesozoic rocks. The older rocks are overlain by organic-rich Lower Cretaceous shales that are thought to have been the source of the hydrocarbons trapped in the super-giant Prudhoe Bay field. Above these shales, younger Cretaceous rocks contain large amounts of coal and some oil and gas. The Beaufort shelf is relatively narrow (30 to 60 miles) and is underlain by a progradational sequence of Cretaceous marine and nonmarine sediments that dip gently north of the Barrow arch. To the east, the Cretaceous rocks are overlain by Tertiary marine and non-marine strata. The geological structure is comprised mostly of large folds. The Cretaceous rocks beneath the Beaufort Sea probably contain organic rich shales at their base as they do onshore. The sandstones higher in the Cretaceous section contain both oil and gas deposits onshore near

^{41/} Grantz, Arthur, and David A. Dinter. Constraints of Geological Processes on Western Beaufort Sea Oil Developments. Oil and Gas Journal, May 5, 1980. p. 310.

^{42/} Ibid.

the coast. It is also possible that some of the pre-Cretaceous rocks, which contain hydrocarbons at Prudhoe Bay, may locally extend across the Barrow Arch and underlie the Beaufort shelf. However, it is not expected that another Prudhoe Bay size field will be discovered offshore in the Beaufort Sea because the larger structures there appear to be complexly faulted, thus limiting the size of the prospective fields and making any hydrocarbons hard to find. The exploration targets in the region will not only be the Permian-Triassic sands, but also Mississippian and Pennsylvanian strata and the younger Cretaceous sands. 43/

During 1968, exploration wells drilled near Prudhoe Bay discovered the largest hydrocarbon accumulation yet found in North America. The field was estimated to contain reserves of about 9.7 billion barrels of liquid hydrocarbons and about 26 tcf of gas. It consists of a succession of stratigraphic accumulations formed on a large structure as a result of the truncation of south and southwest dipping reservoir formations by a Lower Cretaceous unconformity. The main reservoir formation at Prudhoe Bay is the Triassic Sadlerochit sandstone. 44/ The trans-Alaska crude oil pipeline began operations in 1977 and with the help of a drag-reduction additive and the addition of pumping horsepower is now moving crude oil at the optimum Prudhoe Bay production rate, an average of about 1.52 million barrels per day. 45/ Since construction has not as yet begun on a gas pipeline, any produced gas is reinjected into the gas cap over the oil. Plans

43/ Wilson, Howard M. Wildcatters Poised for the Beaufort Sea. Oil and Gas Journal, June 2, 1975. p. 100.

44/ Brosge, W. P., and I. L. Tailleux. Northern Alaska Petroleum Province. Future Petroleum provinces of the United States--Their Geology and Potential. Memoir 15, The American Association of Petroleum Geologists, Tulsa, Oklahoma, 1971. p. 94.

45/ Alyeska Now Moving Peak Prudhoe Flow. Oil and Gas Journal, Feb. 25, 1980. p. 70.

are also being made to inject seawater beneath the oil in the reservoir to maintain pressure and thus increase ultimate recovery by an estimated 5-9 percent. Prudhoe Bay has already produced over 1 billion barrels of oil, more than 10 percent of its total reserves.

Naval Petroleum Reserve No. 4 was transferred to the Department of the Interior in June 1977. The South Barrow gas field, the oldest actively producing field in Alaska, is located in the reserve. It was discovered in April 1949 as part of an early Navy exploration program. The gas is used for the Naval Arctic Research Laboratory and the village of Barrow. The East Barrow gas field was discovered in 1974 by drilling on a seismic anomaly a few miles east of the older field. ^{46/} Original recoverable gas reserves in the South Barrow field were 25 billion cubic feet, about half of which have been produced, while the smaller East Barrow field contains an estimated 12 billion cubic feet of recoverable gas. ^{47/} The fields are of "commercial" size only because the gas is used locally. The Department of Interior has continued the Navy exploration program in the reserve, now renamed the National Petroleum Reserve in Alaska. A 26-well Federal effort has yielded only one potentially commercial discovery. Gas was discovered in the southeast corner of the reserve. The discovery well was not commercial, but it is on a large structure in an area known to contain hydrocarbons. It is immediately adjacent to the Umiat oil field, estimated to contain 70 million barrels of oil, but not yet commercially viable on the North Slope. ^{48/}

^{46/} Lantz, Robert J. Barrow Gas Fields--N. Slope, Alaska. Oil and Gas Journal, Mar. 30, 1981. p. 197.

^{47/} Ibid., p. 198.

^{48/} Gas Find in Alaska Reserve. Department of the Interior News Release. Geological Survey, April 15, 1980.

The Bureau of Land Management is now planning to lease portions of the petroleum reserve to private industry to continue hydrocarbon exploration.

Other prospects on the North Slope include the large Kaparuk field, located some 30 miles west of Prudhoe Bay, with potential oil reserves estimated to be 1.3 billion barrels that may be brought into production as early as 1982. 49/

To the north of Kaparuk a potentially commercial reservoir has been discovered at Milne Point and another potentially commercial discovery has been made east of Milne Point at Gwydyr Bay. Exploration wells in both areas indicate substantial reservoirs, but because of the remoteness of these Arctic locations, additional confirmation wells are necessary to demonstrate commercial size deposits. Other promising areas which may be developed include the Sag Delta, northeast of Prudhoe Bay; and Point Thomson, located about 50 miles east of Prudhoe Bay. 50/, 51/ Exploration wells in these areas have encountered significant amounts of oil or gas.

At a combined Federal-State lease sale in December 1979, high bids of more than \$1 billion were made for leases in coastal bays, on barrier islands, and out to the shelf edge of the Beaufort Sea. Permits to drill on the new State leases were not granted until late in 1980. The first wells were drilled near shore in the winter of 1980-1981. Next winter's drilling is expected to provide

49/ Metheny, Shannon L., Jr. North Slope Field Nearing Production. Oil and Gas Journal, Apr. 13, 1981. p. 129-130.

50/ Wilson, Howard M. North Slope Action Holds West Coast Spotlight. Oil and Gas Journal, May 25, 1981. p. 183.

51/ Exxon Unveils Data on More Alaska Wells. Oil and Gas Journal, Aug. 17, 1981. p. 63.

more general resource information as previously untested prospects under the Beaufort sea will be drilled. 52/

Lying between the Prudhoe Bay region and the discoveries in the Mackenzie River delta of Canada is the 18 million acre National Arctic Wildlife Range. The available geological information indicates that several geologic structures exist in the range. Two are huge, rivaling Prudhoe Bay in size. 53/ Leasing in the range is prohibited by law for at least 5 years, but seismic surveys are permitted. Discoveries of oil and gas on both sides of the range and the existence of the large geological structures, which may indicate potential hydrocarbon traps at depth, are considered to be favorable indications of the existence of hydrocarbon accumulations within the range.

The U.S. Geological Survey considers the Arctic Slope region to be by far the most prospective area in Alaska for hydrocarbon deposits. With Prudhoe Bay (the largest field in North America) already discovered and several other exploration wells showing significant production potential, the Survey has estimated that from 9.4 to 103.1 tcf of natural gas (with a statistical mean of 39.3 tcf) occurs beneath the Beaufort Sea which may be considered recoverable if the technology is developed to allow gas production from beneath the Arctic pack ice; and that from 7 to 84.8 tcf (with a statistical mean of 31.8 tcf) of undiscovered recoverable natural gas exists onshore in the North Slope region. 54/

52/ Operators in Alaskan Beaufort Sea Complete Three Tests, Gear For More. Oil and Gas Journal, April 13, 1981. p. 63.

53/ Moore, J. Cordell. National Arctic Wildlife Range Seen Best Potential For Huge Discovery. Oil and Gas Journal, Aug. 6, 1979. p. 155.

54/ Dolton, G. L., et al., op. cit., p. 8, 9, 11.

J. YUKON-KOYUKUK

The Yukon-Koyukuk area extends south from the Kobuk River to the Yukon River in the area of Koyukuk and Nulato and then continues southwestward to the coastal lowland. It comprises about 100,000 square miles. The region is underlain by predominantly Cretaceous, Mesozoic rocks with exceedingly complex structure. This general structural complexity and the scarcity of favorable reservoir and source beds appear to limit hydrocarbon potential to areas underlain by Cretaceous rocks of shallow marine and nonmarine origin. 55/ A few exploratory wells have been drilled in the area, apparently without success.

The U.S. Geological Survey estimates from 0 to 0.6 tcf (statistical mean 0.1 tcf) of undiscovered recoverable gas for Yukon-Koyukuk basins. 56/

55/ Gryc, George, op. cit., p. 62.

56/ Dolton, G. L., et al., op. cit., p. 11.

APPENDIX III

CRS CONTRACT STUDIES ON ANGTS*

- A. Social Cost-Benefit Analysis and Alaskan Natural Gas
- B. Natural Gas Pipeline Supply Choice and Industrial User Conversion Costs
- C. Public Versus Private Discount Rates in Cost-Benefit Analysis

*CRS does not agree with all substantive aspects of the analysis contained in the following memoranda done by Jensen Associates for the CRS. Nevertheless, these memoranda are reprinted in the appendix because they provide a representative example of thinking in the field by a respected professional consulting firm and provide the interested reader a greater scope of background, opinion and insight in this area.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: Social Cost-Benefit Analysis and Alaskan Natural Gas

A social cost-benefit analysis seeks to answer two basic questions: whether a specific project should be undertaken (benefits exceed costs for the project) and which project(s) should be undertaken if investment funds are limited (the combination of projects which produces the maximum net benefit.)^{1/} These basic questions are similar to those asked by a private enterprise using standard accounting practices to evaluate its investment opportunities. Private accounting practices, however, are unsuitable for evaluating social projects with respect to their impact on the welfare of society as a whole. The reason is simply that what are costs and benefits to particular individuals within a society are not necessarily counted as costs and benefits to society.^{2/}

This shift from a private perspective to a social perspective generates conceptual difficulties in defining and measuring the costs and benefits associated with individual projects. While the market prices for inputs and outputs of projects used in a private analysis are the starting point for social cost-benefit measurement, they prove inadequate where monopoly elements exist in the relevant markets or where volumes are large enough to affect the supply and demand balance for these products. Viewed from a private perspective, a cost-benefit analysis also fails to include all the appropriate impacts of a project on society. For instance, the social costs of pollution are

^{1/} Cost-benefit analysis has also been used to determine the level at which plants operate or the combination of outputs it should produce. These uses of cost-benefit analysis are, however, generally ignored in the literature and are not relevant here.

^{2/} Mishan, E.J., Cost-Benefit Analysis, Praeger, 1976, page x.

not factored into private plant operating decisions beyond the requirements of environmental regulations. Similarly, the social benefits attached to lower energy demands are not reflected in the private decision to conserve fuel.

In the first part of this memo, there is a discussion of some of the basic definitions and measurement principles of social costs and benefits. These comments are not meant to be all-inclusive but rather were chosen to provide a theoretical basis for the discussion of Alaskan (Prudhoe Bay) natural gas which takes place in the second part of the memo. The analysis of this gas supply is itself limited to the social cost at the wellhead plus some additional comments on measuring the net social benefit of marketing this gas.

SOCIAL COST

Within the context of a social cost-benefit analysis, the appropriate concept of costs for a particular project is based on the alternative projects which society does not pursue. Assuming a society's resources are finite, all possible projects cannot be undertaken. To evaluate the social cost of a particular project or policy, a judgment must be made as to which alternatives have been precluded by the selection of this project. Each alternative, in turn, must then be studied to assess the net social benefits which could have been obtained if it had been undertaken. The social cost of the project chosen is the maximum amount of benefits which could have been obtained from among these alternative projects.^{3/}

Comparisons of alternatives are not, however, usually conducted on the basis of whole projects, but rather made on the individual resources employed in the various alternate projects. The cost of an individual project, therefore, consists of its "net inputs"--the goods and services withdrawn from the economy that would not have been

^{3/} Dasgupta, Partha and Sen, Amartya, "Guidelines for Project Evaluation," United Nations, 1972, page 52.

withdrawn in the absence of the project.^{4/} The previous comments regarding evaluation of social costs apply to these net inputs; i.e., the value of these inputs is the maximum benefit they could have produced in some other project. Seen in this light, social costs can best be viewed as opportunity costs.^{5/}

In valuing these "net inputs" in terms of their opportunity costs, two cases can be identified. First, an input could be obtained for the project by reducing the amount available to the rest of the economy (the demand margin). Second, the input could be obtained by increasing the overall supply of the input to society (the supply margin). In the latter case, the cost of the particular input stems from the value of the inputs which are used to produce it. The object of this backward step in the analysis aids in determining which resources society is actually being deprived of because of the project under study.

Once the appropriate inputs have been ascertained, valuing them begins with the market price. This is the appropriate price assuming the input and the product for which it is used are sold under competitive conditions, and the additional demand is small relative to the total product.^{6/} In the real world, markets seldom meet these conditions and therefore they present all of the usual problems of the second best.^{7/} Where the third condition is met, the market price times the number of units needed will provide a measure of the social cost. Where the demand is large relative to the current market, the price will be driven up. In this case, the original market price is too low and the new price too high to be used in measuring the social cost. The appropriate measure of social cost is the old market

^{4/} Ibid, page 53.

^{5/} In Mishan, page 45-74, numerous examples of applying the opportunity cost concept to the social cost evaluation of projects is provided. The comments on unemployed resources are particularly worth reading.

^{6/} Dasgupta, page 53.

^{7/} "Deviations anywhere else in the economy from optional pricing and resource allocation principals make it impossible to conclude as a general proposition that application in any single sector of the normative rules...will be desirable." Kahn, A.E., The Economics of Regulation: Volume I, John Wiley & Sons, Inc., 1970, page 195.

price times the quantity plus the consumers' surplus enjoyed by the previous purchasers of the input based on the volume reduction.^{8/}

SOCIAL COST OF ALASKAN NATURAL GAS

The social cost of Alaskan (Prudhoe Bay) natural gas at the wellhead can be evaluated from two perspectives. The first stems from the basic decision to produce this gas and its social cost in light of the physical relationship to Alaskan crude oil. The second view derives from the value in the various alternatives for disposing of this natural gas after it has been produced.

Prudhoe Bay natural gas is dissolved gas and must be brought to the wellhead in conjunction with crude oil production. Reservoir engineering analysis can determine how much of this gas may be removed and how much must be reinjected to maximize the total hydrocarbon output from the reservoir. The natural gas discussed in this memo refers only to that amount which can be produced according to this production profile.

Alaskan gas and oil are joint products in the classical meaning of that term. As with any activity, there are social costs and benefits attached to its undertaking--here, the production of the hydrocarbons. The allocation of these costs between the two products cannot be based on economic principles but must be essentially arbitrary.^{9/} Since production has taken place without any benefits being derived from marketing the gas, the benefits from crude oil production must be sufficient to overcome these joint costs of production.

From a social perspective, we have only two choices with respect to Alaskan natural gas: either produce it or don't produce it. With respect to the decision to produce this gas, the social costs of production can be viewed as sunk costs. These costs have been counted once in the social cost-benefit analysis of oil production and they are not relevant to the gas decision. Society, having made the decision to produce oil, does not have to give up any additional resources to avail itself of natural gas at the wellhead. The "net input" or social cost of natural gas is zero.

^{8/} This is the standard consumer surplus analysis found in most textbooks. Also in Dasgupta, page 55-56.

^{9/} Alchain, Arman and Aller, William, "Exchange and Production Theory in Use," Wadsworth Publishing Co., Inc., 1969, page 308.

The alternative of not producing this gas which requires foregoing production of the crude oil as well is not a rational alternative. While non-production would, of course, use no resources or factors of production and therefore have a zero social cost, it would also deprive society of the net benefits currently being obtained from the crude oil production. As an alternative to production, non-production, rather than have a net benefit as our earlier definition of alternatives implied, would have a net cost.

While Alaskan natural gas has a zero social cost associated with bringing it to the wellhead, its value in any use is a function of its highest value in other feasible alternate uses--the social opportunity cost. Once Alaskan natural gas has been brought to the wellhead, only three alternatives for disposing of it exist. They are flaring, reinjection, and marketing. Because of conservative ethics, the first alternative, flaring, is not acceptable and can be ignored within the context of a social cost-benefit analysis.

The second option, reinjection, is the one currently being utilized. The primary costs associated with this option include reinjection wells and these costs have been estimated at 15¢/mcf.^{10/} Gas reinjection as a permanent solution also has some long-run negative effects on the volume of oil which can ultimately be recovered and these costs must also be considered in evaluating this alternative. Among the social benefits derived from this option is the availability of a proven supply of natural gas for use in a future time period. An evaluation of this benefit requires an analysis of the energy supply-demand balance in that future period as well as the appropriate discount rate needed to generate the present value of this future benefit. Because of the uncertainties involved in estimating this future balance, the risk component of this analysis, whether accounted for in the discount rate or the benefit measurement, will be high.

In the final option, marketing, the social cost of the natural gas at the wellhead is dictated by its only feasible alternative, reinjection.

^{10/} Chemical and Engineering News, "Methanol Primed for Future Energy Role," April 2, 1979, page 29.

Therefore, the costs and benefits described above for the second option would have to be evaluated to determine if any net benefit existed. If we realistically assume a high rate of discount to account for risk as well as time preference, and a reasonably long period of time to have balance restored to the world energy market, the benefits associated with preserving an energy supply will be small. This low level of benefits must be compared with the 15¢/mcf cost of reinjection and the costs associated with the loss of crude oil production. Estimating the latter cost would require an in-depth analysis of the particular reservoir characteristics as well as the costs of drilling additional wells necessitated by higher gas/oil ratios as reinjection continues, a task beyond the scope of this memorandum. Therefore, merely for convenience of argument here, we have assumed that these costs and benefits balance out and a zero cost of gas at the wellhead can be used in estimating the social costs of the marketing option.

The marketing option itself consists of many alternatives, including building a pipeline to an end-use market, conversion to methanol with shipment through the oil pipeline, and liquefaction. Each of these alternatives should be studied and the option generating the maximum net social benefit should be chosen. It is important to point out that the outcome of this comparison will change depending upon when the analysis is conducted. Prices, product supplies, and technology are constantly changing and these changes will have an impact on the optimal choice among the many alternatives.

Such an analysis, however, is way beyond the scope of this memo. Comments are offered on only two points within this analysis: first, the measurement of the social benefit of providing this gas supply to an end-use market; and second, the allocation of the difference between the net social benefit of the marketing alternative chosen and zero social cost of the gas at the wellhead.

The process for measuring the social benefit of Alaskan natural gas in an end-use market is similar to that described for measuring the social costs of the "net inputs". A decision must be made as to whether this natural gas is supplied as a replacement for an existing energy source or if it is supplied in addition to energy currently available in the market.

In the case of replacement, the value of the social benefit would be based on the resources released by not producing the replaced supply. For domestic sources, this might be other gas production facilities or possibly electric generating plant inputs. For replacement of foreign resources, the benefit value would be the positive net effect on the balance of payments.

Where Prudhoe Bay natural gas is marketed in addition to existing supply, the social benefit must be derived from an analysis of the demand curve. If the incremental supply is insufficient to alter the supply/demand balance, then subject to the problems of monopoly elements the market price will be an acceptable measure of the per unit benefit. If the market price changes, then a measure must be taken of the change in the area under the demand curve as described in the earlier analysis of social cost.

Whether Alaskan natural gas serves as a replacement or as a supplement to the U.S. energy supplies, the impact of the additional energy available on the world market provides a social benefit. This benefit comes from the reduced pressure on world crude oil prices and to the extent that any society imports oil that country shares in this social benefit.

Naturally these benefits (the gas supply and the reduced pressure on world crude oil prices) must be combined with other identifiable social benefits and then weighed against the social costs to determine the net benefit to be derived from this alternative.

The combination of this net benefit for any alternative chosen under the marketing option and the zero social cost of Alaskan natural gas at the well-head raises the question of how the overall net benefit will be distributed to the members of society. The mechanism for distributing this net benefit is the price paid to producers. The higher the price, the greater the share of net benefits captured by the producers. The lower the price, the greater the share of net benefits to the end-user. While society may be concerned with distribution problems, in terms of the purposes of a cost-benefit analysis in choosing between alternative projects the size of the total benefit is critical, not its distribution.^{11/} The difference between

^{11/} Mishan, page 67.

the social cost and benefits sets a range of prices over which society would be willing to pay producers. Within that range, the social cost-benefit analysis provides no guidance as to what that price should be. In the case of Alaskan natural gas, Congress solved the distributional aspects by setting the price for this gas in the Natural Gas Policy Act.^{12/}

^{12/} Public Law 95-621, 92 Stat. 3368, November 9, 1978.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: Natural Gas Pipeline Supply Choice and
Industrial User Conversion Costs

This memo discusses qualitatively two different topics currently of importance in the natural gas industry. The first subject deals with the question of how gas transmission companies choose among alternative sources of supply. The second topic concerns the views of industrial gas users on conversion costs to alternate fuels in light of uncertainty surrounding natural gas supplies.

PIPELINE SUPPLY CRITERIA

Transmission companies provide a transportation link for natural gas from producing areas to market areas. In this capacity, these companies seek to match the throughput of their pipelines with the varying demand for gas found in the marketplace. Prior to the 1970s, when gas was quite plentiful, the primary problem in matching supplies with demand was seasonal swings in spaceheating loads. Longer range variations in demand could be met through exercise of contract flexibility in rates at which production could be taken from dedicated reserves, or by securing access to additional reserves. During the gas shortage period of the 1970s, gas transmission companies lost both of these means of varying long-term supplies. Gas purchase contracts became more rigid in requirements for rapid rates of take (or reserve depletion) and additional supplies were scarce. Also, during the latter part of the 1970s, certain gas prices rose rapidly relative to competing fuels causing loss of demand through conservation and, in some areas of the U.S., actual switching to other less expensive fuels occurred. Thus gas costs to transmission companies have become more critical today than in prior years when federal regulations kept field prices well below free market levels.

Jensen Associates, Inc.

These two criteria--matching supplies with demand and the increasing importance of gas costs--encompass the principal concerns of gas transmission companies when they select sources of gas supply. Other factors such as the geographical location, quality and pressure of the gas, or the capital investment required can be discussed in terms of these two major criteria.

Meeting Forecast Demands

In selecting from alternate gas supply possibilities, natural gas pipelines seek to match supply availability with the market demands which have been forecast for the gas distribution companies and the direct industrial firms which these pipelines serve. This supply/demand balancing has both long- and short-term components. The former relates more to the production profile of gas supplies while the latter refers to the flow flexibility available from these supply sources.

For the long-term matching of supply and demand, a pipeline will typically forecast the volume demanded over a 20-year period as shown in Figure 1. Against this demand, individual supply sources by volume are aggregated. Ideally, one would like to have a complete matching of supply and demand as shown in this figure. To achieve this goal, the pipeline would like to be able to vary over a wide range the take from any individual source. Unfortunately, this is not very realistic.

Today many pipeline companies face a deliverability curve more like that shown in Figure 2. In the near term supplies exceed demand, but beyond a point four or five years out, there is a sharp drop-off such that demand exceeds supply. To some extent this will always be the case as gas reservoirs with high deliverability rates are added to the total reserve base. On the other hand, it shows why pipelines would be willing to pay a premium for gas reserves having a long-term production profile. This is seen in the higher deregulated prices being paid today for some deep gas which characteristically produces at a slow rate over a long period of time. At the same time, it is also an advantage associated with coal gasification and Alaskan gas. Besides providing natural gas over an extended period, this gas will not be available until the drop-off period is reached

Figure 1

PROJECTED GAS SUPPLY AND DEMAND

FOR A GAS PIPE LINE COMPANY

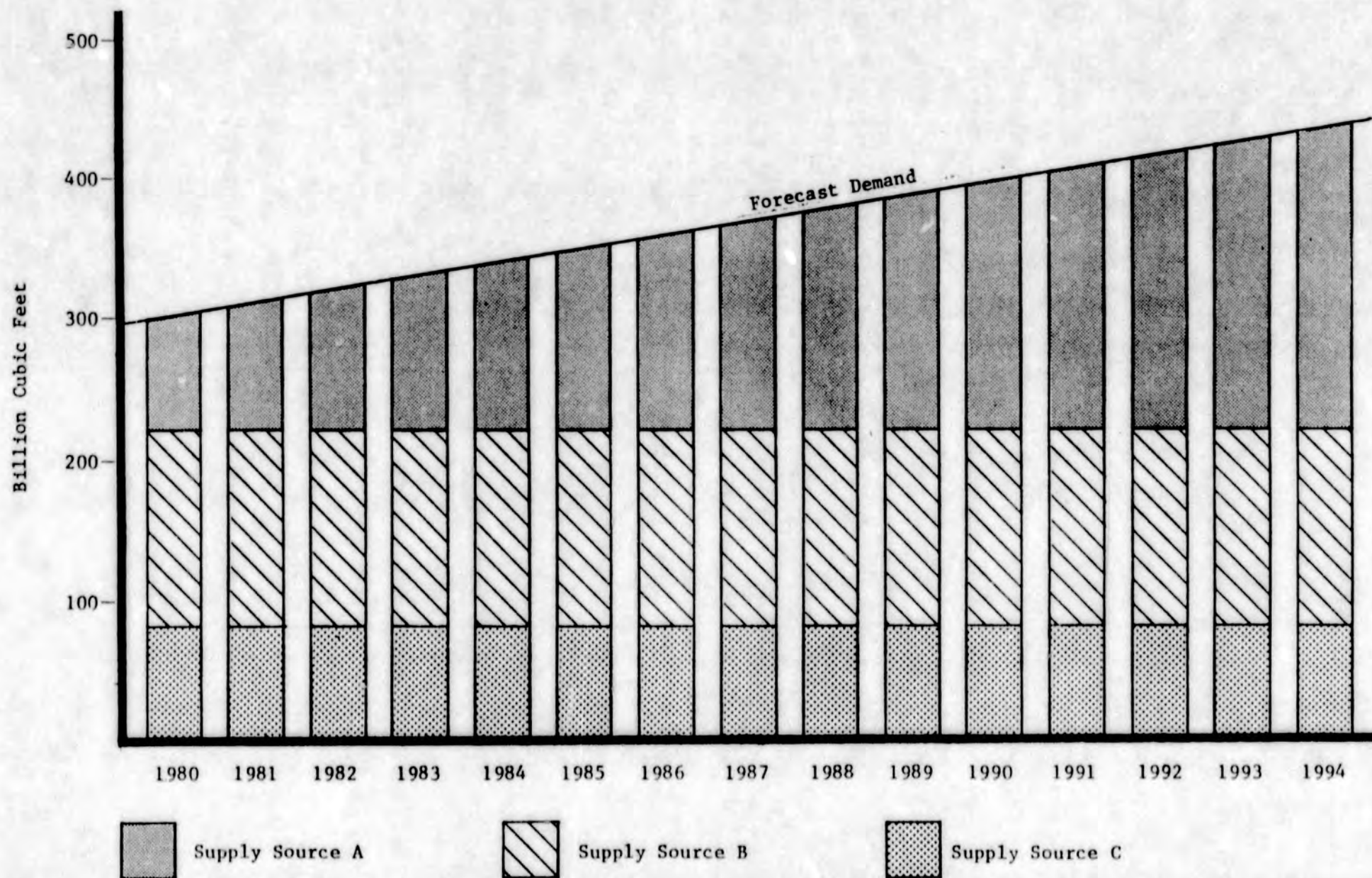
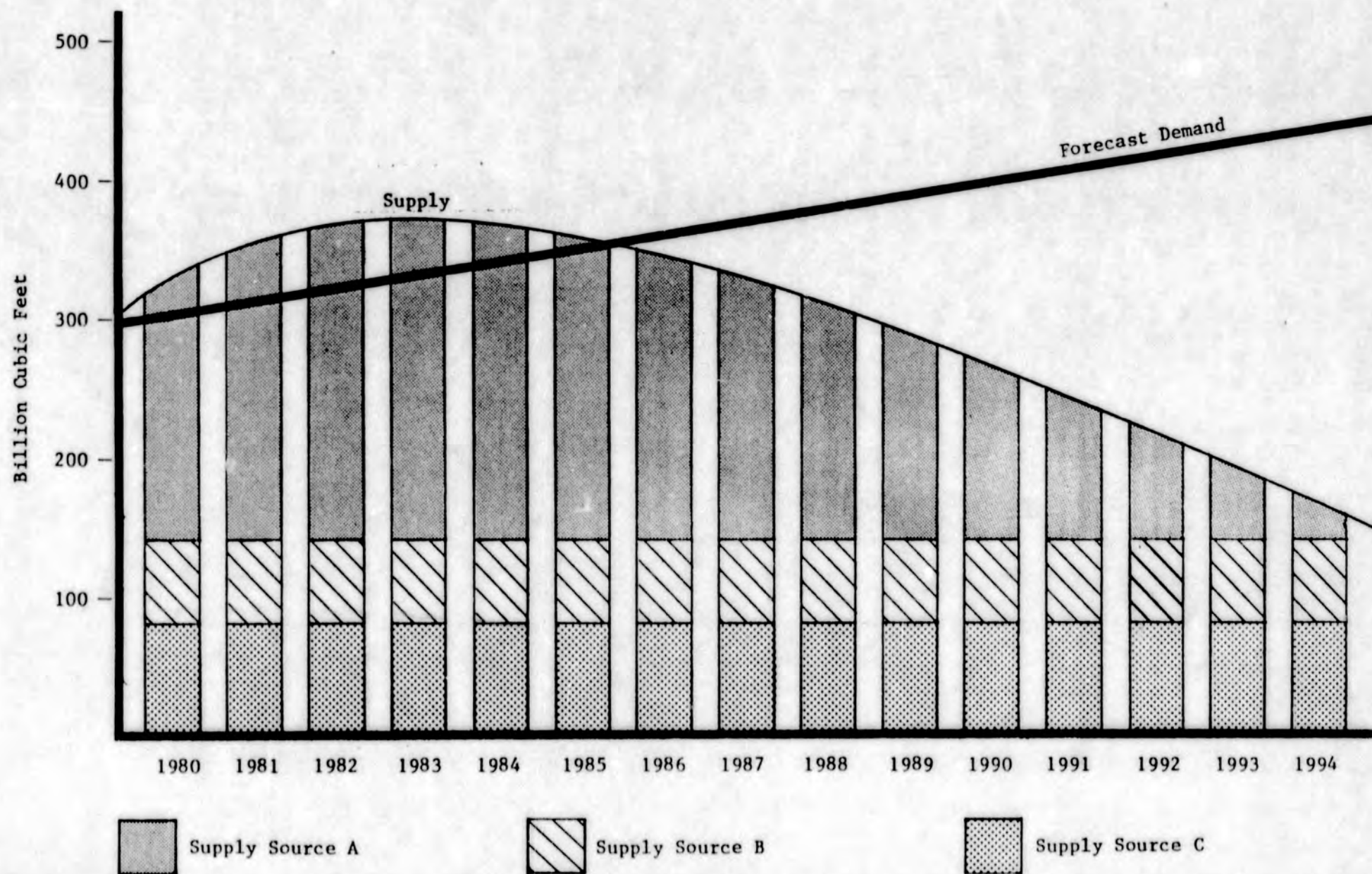


Figure 2

PROJECTED GAS SUPPLY AND DEMAND
FOR A GAS PIPE LINE COMPANY



by most pipelines. In terms of the long-term matching of supply and demand, these projects exhibit two favorable supply characteristics--the long-term constant rate production profile and the delayed production start-up date.

The reliability of these long-term supplies must also be considered in matching demand forecasts. Both physical and political disruptions to supply sources represent possible drawbacks to otherwise acceptable solutions to this long-term need. The recent cut-off in Algerian LNG trade is a prime example of source which adds a constant supply volume over an extended period of time but which has a reliability disadvantage.

For the short-term, flexibility in production becomes a very important factor in choosing among gas supplies. Pipelines experience supply and demand excesses in the long-run pattern because either the production profiles of the types of supplies available do not match their specific needs or because of economic and seasonal demand fluctuations. To meet these changes in the short-term demand and supply balance, pipelines would like to have the ability to vary the volume of gas received from their supply sources.

In the past, a pipeline could meet this need by availing itself of the variations in production rates allowed by individual gas supply contracts. During the 1950s and 1960s, take-or-pay provisions in most contracts permitted the pipeline to take as little as 60-70 percent of the deliverable volume from a gas well with approximately five years allowed in which to make up lesser takes. In this way, the pipeline could reduce its take in periods of low demand and use the excess supply in later periods of high demand thus providing flexibility to its supply position.

The take-or-pay provisions of the 1970s, however, have differed from earlier contracts in that the typical pay level has been set at 90 percent of deliverability or higher. This has narrowed the range that the pipeline has for matching supply and demand. If it takes less than 90 percent for any significant period of time, the ten percent margin available in later periods makes it difficult to make up these volumes. If the reservoir is of a rapid decline type, the reduced deliverability at a later date aggravates this problem.

Some additional flexibility can be achieved if the pipeline owns the gas prior to delivery to the pipeline. This may come about through ownership of gas in storage facilities, in producing fields, or by ownership of synthetic gas production facilities. The value of this ownership derives from controlling the flow of gas when other sources cannot be modulated. The pipeline may face lower total costs by increasing its flexibility in this manner.

Increasing Importance of Field Price and Other Pipeline Costs

Among the considerations of pipeline purchasers when selecting a source of gas supply, the cost of the gas plays an important role. Of course, cost has always been a central consideration. But a number of changes in energy markets during the past decade have focused the attention of purchasers even more upon the cost question.

One such change has been the gradual decontrol of wellhead prices of natural gas. From the mid-1950s until the Natural Gas Policy Act of 1978, the wellhead ceiling prices of natural gas sold to interstate pipelines were established by the Federal Power Commission (F.P.C.). Pipelines were not free to bid for new supplies of gas by offering to pay prices above these established ceilings. Although pipelines became deeply involved in F.P.C. price-setting proceedings, individual pipelines (and individual producers) generally had little influence over interstate wellhead prices. Under such a regime, with prices essentially the same for all sources within any given region, it is understandable that the field price was not the primary cost consideration of pipelines seeking gas supplies. To a certain extent, rate-of-take became a proxy for higher price, with pipelines offering to accept faster rates of production (and hence faster payback periods) to producers as an inducement to commit reserves to interstate sale. Pipelines also offered producers other cost-absorbing inducements such as building production facilities or assuming gas conditioning obligations.

As natural gas prices are decontrolled, individual gas supplies are being offered to interstate pipelines at different prices. Producers having reserves located near an existing pipeline or near a market will be capable of obtaining higher prices as they capture some of the transportation

cost savings inherent in their location. Producers will presumably ask higher prices for long-term gas supplies (that is, supplies sold under a contract specifying a lower minimum daily quantity or a lower take-or-pay level) than for shorter term supplies. Thus, pipelines comparing alternative incremental gas supply contracts must look more carefully at the field price as an element of total cost in the comparison process.

Another major change which has occurred in energy markets and which has focused pipeline attention upon gas cost is the tremendous increase in all energy costs to end users since 1973. This increase has made all end users sensitive to absolute and relative energy costs. Significant conservation in the use of energy has been achieved as a consequence, and more may be anticipated as energy prices continue to rise.

Natural gas prices to end users have been a part of this general rise in energy prices, not only as a consequence of the gradual decontrol of wellhead prices but, even before 1978, as a result of higher ceilings set by the F.P.C. Interstate pipelines, as a group, have gone from a situation of chronic undersupply (inability to meet their commitments to local distributors and end users) to a situation in which it is difficult to sell additional volumes of gas into some end-use markets. (To be sure, the present oversupply situation is also a consequence of the current slowdown in economic activity.) The pipeline purchaser, recognizing that its ultimate markets for natural gas are increasingly price sensitive, must be equally price sensitive when acquiring new supplies, which again focuses his attention on the cost element in choosing among alternative sources of gas.

The increasing importance of cost in gas acquisition decisions is accentuated by another important change which has taken place in energy markets in recent years. Not only have energy prices risen substantially, but the degree of uncertainty about future energy prices (and availability) has also increased. This means that even if a pipeline acquires a long-term gas supply at what seems to be an acceptable cost (including escalation over the life of the contract), future events could render that gas too costly for resale without a loss. The inherent uncertainty in energy

prices, due to the important role of diplomatic, political and military factors in affecting those prices, forces the risk averse pipeline purchaser to seek lower cost gas supplies and, if possible, gas supplies with limited price escalation potential.

Other aspects of the cost of acquiring natural gas have also taken on increased significance as a result of these changes in energy markets and the variability of field prices for natural gas. For gas acquired through the pipeline's own production rather than through purchase from a producer, greater attention must be paid to lease acquisition, exploration, development and production costs. For purchased gas, the traditional price adjustment for differing Btu content is given closer scrutiny. Also, the potential cost consequences of interruptions in supply from some sources (such as imported LNG) are given increased consideration. While these cost-related elements have always been important in pipeline gas supply decisions, not so much was at stake when gas prices were controlled at levels well below market clearing levels. Under these conditions, additional gas acquisition costs could be passed on to the consumer with a minimal loss in sales volume due to the higher price of alternate fuels. As natural gas markets approach deregulation and thus price parity with these other fuels, even small differences in the gas acquisition costs could have a significant effect on the volume of gas sales to end users.

UNCERTAIN GAS SUPPLIES AND INDUSTRIAL DEMAND

In this section of the memo, the question of how industrial gas users look at conversion costs to alternate fuels when gas supplies are uncertain is discussed.

The conversion costs faced by industrial users can be divided into annual operating costs and capital investment costs. These two costs can be further divided into fuel related and process related costs. Each alternate fuel (oil, coal, electricity, etc.) imposes at least the fuel cost differential as a fuel-related operating cost. To varying degrees, these alternate fuels also impose fuel-related investment costs. Coal, for instance, requires additional investment in space for stockpiling; oil in tank facilities. If the production process employed by the industry

is altered by the choice of fuel used, then additional operating costs and investments will be incurred in producing the previous output.

The existence and relative importance of these four cost categories varies substantially between industries. It would, therefore, be impossible to generalize about the specific conditions which would make fuel switching profitable. However, this variation does generate a curve of increasing conversions as conditions of supply and price deteriorate in the natural gas market. Based on past experience, boiler fuel users and other buyers of gas for its Btu content will be the first to shift because they face only the fuel related costs, including both capital and operating components. Economies of scale will, in turn, provide greater conversion incentives to larger users under equal price conditions.

During the period of the 1970s, industrial users were faced with uncertain gas supplies and often total loss of supply through curtailments. In these latter cases where alternate energy sources were necessary, industrial users appear to have made short-range decisions based upon consideration of several factors. The relative as-burned cost of the Btu's utilized, the relative simplicity of facility conversion, and the retained flexibility to utilize other fuels were the most influential of these factors.

Past studies have shown that the majority of these conversions were to oil. Normally oil burning facilities can be designed to utilize gaseous fuels with little additional investment and with simple fuel switching procedures. The higher purchase price of oil and its potential supply disruptions typically were not enough to justify the more costly and time consuming conversions to coal or electricity.

For the future, continued uncertainty with respect to availability of natural gas will have several effects. First, industrial users with dual burning capability will maintain this equipment at a higher level of readiness. Second, some gas load loss may occur as industrial plants seek to preserve a position with the fuel oil distributors. Third, over the long-term industrial efforts will be expended seeking a lower-cost, more secure source of energy.

Date: September 18, 1981

Memo To: Gary Pagliano
Congressional Research Service

From: Robert G. Paszkiewicz
Jensen Associates, Inc.

Subject: Public versus Private Discount Rates in Cost-Benefit Analysis

Typically, managers in both the public and private sectors of the economy evaluate investment options based on the expected returns over time. The present value technique of discounting future costs and benefits has been accepted as a suitable method of performing these project evaluations. In utilizing the present value technique, the choice of the discount rate to be employed will have a critical impact on the outcome of the evaluation^{1/}; and, therefore, great care must be taken in the selection of the appropriate rate of discount.

This paper assumes the reader understands the basic objectives of the present value technique and how it works. The purpose of this paper is limited to a discussion of the differences between the social and private rates of discount. As a basis for this comparison, a definition of the private rate of discount is developed and then followed by a similar effort for the social rate. In a subsequent section, the comparison of these rates is carried out. The final section of this paper provides some very rough numerical estimates of current rates.

^{1/} A study by Fox and Herfindahl found that of federal projects approved at the rate authorized by Congress in 1962, 2.63 percent, only 20 percent of the projects would have been acceptable at an 8 percent discount rate and only 36 percent at a 6 percent discount rate. Irving K. Fox and Orris C. Herfindahl, "Attainment of Efficiency in Satisfying Demands for Water Resources," American Economic Review, Vol. 54, no. 2 (May 1964), page 198.

More recently the choice of the social discount rate became the subject of debate between President Carter and Congress over the deletion of 19 water resource projects in the 1978 U.S. Budget. The President used a 6.38 percent rate of discount to show that these projects had a benefit to cost ratio less than unity. Several Congressmen argued that this rate was higher than the law allowed and the projects should be approved. Raymond F. Mikesell, "The Rate of Discount for Evaluating Public Projects," American Enterprise Institute, Washington, D.C., 1977, page 5.

A. THE PRIVATE FIRM'S DISCOUNT RATE

For the private firm, the appropriate rate of discount to employ in analyzing investment decisions by the present value technique is the firm's cost of capital. The intuitive logic of this approach can be seen from the following simplified example. Assume that all investments are debt financed and the market rate of interest is 10 percent, which also then becomes the firm's cost of capital. Under these circumstances, using the 10 percent cost of capital figure in the present value formula the firm will accept all projects for which the return is at least \$111 a year from now if the costs are \$100 today and reject those projects for which the return is \$109 or less.^{2/} Employing a discount rate higher or lower than the cost of capital would deny the conventional assumptions of economic rationality.^{3/}

In practice measuring a firm's cost of capital entails a substantial amount of judgment. While the required payments to the current debt portion of total capital are explicitly stated in contractual terms, the costs of existing equity capital cannot be directly observed. Estimates of the equity cost component are the subject of testimony by financial experts in every utility rate case before Federal and state regulatory bodies. The sheer number of these consultants and the number of different theories employed by them--comparable earnings, discounted cash flow, and capital asset pricing models to name but a few--means that the cost of capital employed in the present value formula is at best an approximation.

Assuming that a reasonable estimate of the firm's current cost of capital can be made, this rate would be an appropriate discount factor

^{2/} Partha Dasgupta and Amartya Sen, "Guidelines for Project Evaluation," United Nations, 1972, page 18-19.

^{3/} If the firm chooses a discount rate of 20 percent, it would reject a project which returned \$115 a year from now even though it could borrow the \$100 costs today and repay only \$110 a year from now thus gaining \$5. Similarly, if the firm chooses a rate of 8 percent, it would accept a project which returned only \$109 a year from now even though it would have to repay \$110 for the investment of \$100 today, and thus lose \$1.

only if the risks associated with the new project are identical to the firm's existing level of risk.^{4/} Since the firm's current cost rate for debt and equity capital were determined by the present level and share of risks borne by the individual suppliers of capital, a change in risk will necessitate a change in the cost rates from the capital sources. For example, if a new project to be undertaken will be more heavily debt financed than the existing capital structures of the firm, then the equity holder's risk will have increased and his demand for additional compensation will tend to raise the total cost of capital, while the lower cost of debt capital relative to equity will tend to lower the total cost of capital.^{5/}

An analyst for a private firm wishing to use the present value formula needs to determine the company's cost of capital to find the appropriate rate of discount. Unfortunately, no procedure for measuring the theoretically correct "cost of capital" has been universally agreed upon by the experts.

B. THE SOCIAL DISCOUNT RATE

Selection of an appropriate rate of discount for project evaluation by public investment managers would be a difficult task even if there was a universally accepted definition of the social discount rate. Unfortunately, economists have advanced many notions of what this definition should be and how it should be applied. Two general theories on how the social discount rate should be derived have dominated the discussion

^{4/} Charles W. Haley and Lawrence D. Schall, "The Theory of Financial Decisions," McGraw-Hill, 1979, page 334.

^{5/} Traditional theory holds that as a company increases its leverage through tax deductible debt borrowing, its cost-of-capital curve will decline until the risk associated with the higher leverage becomes the dominant factor for lenders. Beyond this point, both the debt and equity cost rates will increase. This theory has been disputed by Modigliani and Miller in "The Cost of Capital, Corporate Finance, and the Theory of Investment." The authors concluded that the firm's cost of capital curve was flat. This means that the average cost of capital is independent of a firm's capital structure and equal to the capitalization rate of a total equity stream in its risk class. This point is discussed in Sam R. Goodman, "Techniques of Profitability Analysis," John Wiley and Sons, New York, 1970, page 112.

by public policy participants. They are the social time preference and the opportunity cost approaches.

The social time preference rate for discount is based on the government's estimate of the relative value that citizens collectively assign to current versus future consumption.^{6/} The problem of determining the appropriate values or weights that society places on consumption in individual years now and in the future can be transformed into the standard present value formula by using current consumption as the unit of value and assuming the marginal utility of consumption over time diminishes.^{7/} The choice of weights thus becomes a choice of discount rates.

In making this choice of an appropriate discount rate under the social time preference theory, advocates of this position look at bond market data in general and the government bond rate in particular. However, the rates in this market reflect the collective preferences for individually

6/ P. D. Henderson, "Investment Criteria for Public Enterprises," in Public Enterprise edited by R. Turvey, Penguin Books Ltd., Middlesex, England, 1968, page 97.

7/ Looking at the single objective of aggregate consumption, and denoting the net aggregate-consumption effect (benefits minus costs) in year t by B_t , the overall aggregate-consumption benefit B^* would be

$$B^* = B_0 + B_1 + \dots + B_t$$

for a project whose useful life is t years. If we make present consumption the unit of account this equation becomes

$$B^* = B_0 + V_1 B_1 + \dots + V_t B_t$$

where $V_1, \dots, V_t$ decline over time to reflect the diminishing marginal utility of consumption. The weights in this formula are such that a decline of \$1 in B_0 can be offset by an increase of $V_1 B_1$ or of $V_t B_t$. If $V_t = 0.5$ than B_t would have to increase by \$2 to compensate for the charge of \$1 in B_0 . If we make the simplifying assumption that these weights, $V_1, \dots, V_t$, decline at a constant percentage over time, simple algebra can transform this formula into the standard present value formula where i , the social discount rate, equals

$$i = \frac{V_t - V_{t+1}}{V_{t+1}}$$

the rate of change in weights. See discussion in Dasgupta, page 154-156.

accumulated capital, not the individual preferences for collectively accumulated capital.^{8/} Each individual may be willing to sacrifice more than he would in his private capacity, and to place a lower premium on current versus future consumption, if he is certain that the sacrifice will be shared collectively by the community.^{9/} Thus, in this case the social discount rate would be lower than these market rates of interest.

An alternative basis for defining the social discount rate utilizes the opportunity cost to society of undertaking a particular project. This cost is equal to the value to society of the use to which the resources employed in this project would have been put in the absence of this investment.^{10/} In developing this approach, it has been argued that any public investment project must be regarded as displacing an equal amount of private investment.^{11/} This is essentially a long-run view where the individuals in society make a conscious choice between public and private investment. Given this assumption, the appropriate social discount rate is the average opportunity cost of capital in the private market. Use of a rate higher or lower than this private investment rate of return will make society worse off in an economic efficiency sense.^{12/}

Relaxing the long-run assumption of an equivalent replacement of private investment, allows the more realistic situation where government funds come from more than just the private capital market. Through its taxing powers, the government in practice obtains investment funds by reducing personal consumption, personal saving, government current expenditure, etc. The opportunity cost approach can be adjusted to account for these different sources

^{8/} Peter G. Sassone and William A. Schaffer, "Cost-Benefit Analysis, A Handbook," Academic Press, New York, 1978, page 109.

^{9/} Henderson, page 98.
Sassone, page 105-111. The authors provide two bases for this argument; one in terms of utility theory and one in terms of game theory.

^{10/} Henderson, page 103.

^{11/} Jack Hirshleifer, James C. DeHaven, and Jerome W. Milliman, "Water Supply," University of Chicago Press, 1960, page 173.

^{12/} Lee G. Anderson and Russell F. Settle, "Budget-Cost Analysis: A Practical Guide," Lexington Books, 1977, page 85-87. The argument is similar to that in footnote 3.

of funds by developing an average weighted rate based on the individual cost rates.^{13/}

C. PUBLIC VERSUS PRIVATE DISCOUNT RATES

Differences between the social and the private rates of discount can be shown to exist on the basis of the preceding definitional discussion. If the time preference theory for social discounting is accepted as the proper foundation for determining the appropriate rate, then the market rate of interest or capital cost will be higher than the social rate. The market rate of interest does not reflect the collective sacrifice of current versus future consumption obtainable for investment in public projects; but rather reflects only the individual willingness to make such sacrifices.

Under the opportunity cost approach to choosing a social discount rate, the utilization of realized private rates of return builds into the interest rate measurement an average allowance for risk present in the private sector. Use of this rate implies that public investments have risk characteristics similar to those prevalent among private firms.^{14/} However, in the absence of the threat of bankruptcy, the government cannot reasonably be expected to have risks comparable to an individual firm within the private sector.^{15/} Therefore, we would expect the social discount rate to be different from that of a private firm undertaking the same investment and probably the social rate would be lower.

D. ESTIMATES OF CURRENT DISCOUNT RATES

The scope of our contract does not permit the extensive efforts which would be required to develop estimates of the proper discount rates to be

^{13/} Anderson, page 88.

^{14/} Subcommittee on Economy in Government, Joint Economic Committee, "Economic Analysis of Public Investment Decisions: Interest Rate Policy and Discounting Analysis," Washington, D.C., 1968, page 14.

^{15/} It has been argued that for those projects which have no counterpart in the private sector, the opportunity cost to society should be used for the discount rate. Where there are equivalent private projects, the opportunity cost of capital to these private firms should be used. Ibid page 15.

used for evaluations of either the public or private investment in the alternative gas streams under consideration. The following comments are intended only as a rough approximation as to what appropriate rates may be.

For the social discount rate, the Federal government prescribes two rates depending upon the type of project undertaken. Water resource projects are discounted by a rate which is related to the average cost of Federal borrowing.^{16/} This rate currently stands at 7.375 percent.^{17/} For the majority of investment projects undertaken by the Federal government, the Office of Management and Budget has dictated a 10 percent rate. This rate is judged to be an estimate of the average rate of return on private investment, before taxes and after inflation.^{18/}

In the private sector, determining the appropriate rate of discount requires estimating the opportunity cost of capital to the firm planning to undertake the investment project. A reasonable approximation to this rate can be made by taking the allowed rate of return on equity in recent natural gas pipeline cases and combining it with the prime rate to yield an average cost of capital. As of this writing, the prime rate was 20 percent and the equity return allowed was 14 percent.^{19/} Using a debt to equity ratio of 41 percent to 59 percent and an effective tax rate of 44 percent,

^{16/} "Standards for Planning Water and Related Land Resources," "Water Resources Council and Related Land Resources," Federal Register, Vol. 39, 1974, page 29242.

¹⁷ Federal Register, Vol. 45, 1980, page 70167.

^{18/} Office of Management and Budget, "Discount rates to be used in evaluating time-distributed costs and benefits," Circular-A-94, March 27, 1972, page 4.

^{19/} Prime Rate = 20 percent. Wall Street Journal, September 18, 1981, page 41.

Equity Return = 14 percent. United Gas Pipe Line, F.E.R.C. Order No. 99, October 10, 1980. Transcontinental Gas Pipeline, F.E.R.C. Order No. 59, August 30, 1980.

this translates into a pretax return of 23 percent.^{20/} Assuming an inflation rate of 8 percent, this would be equivalent to a real discount rate of 15 percent. The measurement of the cost of capital is sensitive to the debt/equity ratio and tax rate chosen. If we were to use the debt/equity ratio of 75 percent to 25 percent discussed for ANGTS, the private discount rate or cost of capital would be 21 percent,^{21/} or a real rate of 13 percent. Determining the appropriate private discount rate thus depends on the capital prospects of the private firm which in fact would undertake the investment.

^{20/} American Gas Association, Gas Facts 1978, Tables 133 and 139, data for Transmission Companies, pages 160 and 169.

$$\begin{array}{lcl} \text{Cost of Debt} & = 20\% \times .41 & = 8.2 \\ \text{Cost of Equity} & = 14\% \times .59 \times \frac{1}{1 - .44} & = 14.7 \\ \text{Cost of Capital} & = & = 22.9 \end{array}$$

where effective tax rate = .44.

^{21/} "Determination of Incentive Rate of Return, Tariff, and Related Issues," (ANGTS), F.E.R.C., Order No. 31, June 8, 1979, page 64.

$$\begin{array}{lcl} \text{Cost of Debt} & = 20\% \times .75 & = 15.0 \\ \text{Cost of Equity} & = 14\% \times .25 \times \frac{1}{1 - .44} & = 6.2 \\ \text{Cost of Capital} & = & = 21.2 \end{array}$$

**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

MEMORANDUM

State of Alaska

TO: John W. Katz
Commissioner

DATE: November 30, 1981

FILE NO:

Jeff Haynes
Deputy Commissioner

TELEPHONE NO:

FROM: Mary Halloran ^{MH}
Special Assistant
to the Commissioner
Natural Resources

SUBJECT: Gas Pipeline Financing

To facilitate your review of the massive amounts of information related to the Alaska Natural Gas Transportation System (ANGTS) and its financing, this memorandum summarizes the major points of the basic documents related to the project's financing. I was aided in this work by Robert Loeffler who provided a chronological list of most of the basic materials and copies of the materials themselves.

I. President's Decision and Report to Congress on the Alaska Natural Gas Transportation System.

The ANGTS enabling decision by President Carter in September, 1977, contains specific terms and conditions for financing of the project. Among those terms are the following:

1. Northwest Alaskan Pipeline Company, then known as Alcan, shall provide for private financing of the project, and shall make final arrangement for all debt and equity financing prior to initiation of construction.
2. The Federal Power Commission (later became the Federal Energy Regulatory Commission, or FERC) shall set a variable rate of return on equity to reward project completion under estimated budgeted cost and to penalize cost overruns.
3. Neither the project sponsor nor any purchaser of Alaska gas shall be allowed to use any tariff which would compel the purchaser or ultimate Prudhoe Bay gas consumer to pay a fee or payment prior to completion and commissioning of operation of the pipeline system.
4. The Alcan Pipeline Company or its successor is not open to ownership participation by producers of Alaska natural gas.

Another important provision of the Decision was to prohibit any project ownership by Alaska gas producers, except provision of guarantees for project debt. The prohibition covered producers' having equity membership in the sponsoring consortium, voting power in the project, any role in management

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or operations of the project, and any continuing financial obligation which might impose anti-competitive conditions on project debt.

In the section of the Decision (pp. 50-66) dealing with the agreement on principles vis-a-vis financing between the U.S. and the Canadian governments, the understanding that pipeline construction will be privately financed was reiterated. In addition, provisions were made regarding non-discriminatory tax treatment of the pipeline by the Provinces of British Columbia, Alberta and Saskatchewan and by the Yukon Territory. Note was made, however, that should the State of Alaska require creation of a special fund or funds (for socioeconomic costs) not fully reimbursable in connection with pipeline construction in Alaska, that the Governments of Canada or the Yukon Territory will have the right to take similar action.

The President's Decision also contained an analysis of pipeline financing (pp. 100-127) which concludes that the project can be privately financed (supporting, not surprisingly, the condition of the Decision that the project is required to be privately financed). It boldly concludes, "Novel regulatory schemes to shift this project's risks from the private sector to consumers are found to be neither necessary nor desirable. Federal financing assistance is also found to be neither necessary or desirable, and any such approach is herewith explicitly rejected."

At that time the project was already labeled the "largest privately financed energy project ever undertaken" with a price tag of \$10 to \$15 billion. Therefore, the authors of the Decision proposed a plan to balance project benefits and risks which had four main provisions:

1. Equity investment would be at risk under all circumstances, and budgeted equity investment would be considered the first funds spent. The rate of return on equity would compensate sponsors for bearing this risk.
2. Producers and the State of Alaska, as direct and major beneficiaries, should participate in pipeline financing either directly or in the form of debt guarantees.
3. Cost overruns would be shared by equity holders and consumers through use of a variable rate of return on common equity.
4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences.

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The authors of the Decision determined that pipeline financing would be successful without consumer noncompletion agreements, reasoning in part that there was sufficient credit support capacity among the direct beneficiaries to assure pipeline completion without assistance from consumers. They counted among those beneficiaries the gas transmission companies, gas producers, and the State of Alaska.

"The benefits of these parties sufficiently outweigh the risks associated with the project so that it is reasonable to expect them to provide support at small additional cost to consumers" (p. 102).

Another unique aspect of the proposed financing plan was that Alcan, now Northwest Alaskan, proposed to raise capital through "project financing" rather than the more traditional "balance sheet financing" normally used in the gas pipeline industry. Revenues from the project itself were expected to pay for its operating costs, interest and principal on debt, and a return on, and ultimately a return of, equity to its investors. (Equity was later set at 25% of project cost, and debt at 75%.)

The Decision found the project demonstrated basic economic soundness: "Even under extreme cost overruns, the delivered cost of Alaska gas will be economically attractive" (p. 105). Delivery of Alaskan gas was assumed to begin January 1, 1983, at a cost of \$10.3 billion. Projected sources for the funds were U.S. and Canadian banks, U.S. and Canadian long-term debt, and U.S. and Canadian common stock. The authors of the Decision reasoned that as the total assets of the gas transmission industry at the end of 1976 were only \$26 billion, the "project must be seen as a corporate entity in itself, capable of issuing and servicing its own debt and equity" (p. 108). They also concluded that at that time the investment's importance in terms of the total capital markets was "modest." Equity was to come from the gas transmission or distribution companies, with debt from the capital markets mentioned earlier.

The Decision suggested that cost overrun financing, an issue from the inception of the project, could be resolved by enlarging the sponsor group to include as participants in financing the gas producers (Exxon, Arco and Sohio) and the State of Alaska.

Producer participation in financing was called for due to their beneficiary status and their financial strength. Similarly the State of Alaska was singled out as a possible financial participant due to its resultant revenues from project success (royalties, severance taxes, and property taxes), and the benefits of use of natural gas inside the State. Never was the contradiction between the Decision's emphasis on private financing and its inclusion of the State of Alaska as a financial participant explained.

The authors of the Decision also chose to interpret an indication of State interest in El Paso (a Northwest competitor) project debt by former Revenue Commissioner Sterling Gallagher (letter of July 19, 1977, from Gallagher to Roger C. Altman, Assistant Secretary, Capital Markets and Debt Management) as a "willingness and ability" of Alaska to guarantee up to \$900 million of the El Paso project debt. The implication was that comparable State interest might be found for the Northwest project. (The Decision's authors ignored the caveats expressed explicitly in Gallagher's letter, such as the need to establish a 50 percent contribution level to the Permanent Fund for all oil and gas royalties; the express resolution of the Alaska Legislature to limit study of State participation in financing to the El Paso or all-Alaska route; and the need for legislative approval for implementation of any financing proposal).

The Northwest proposal differed substantially from that of its competitors in that El Paso stated that consumer guarantees through an "all-events" tariff and federal backstopping through federal loan guarantees for LNG tanker fleet financing would be vital. Northwest said no consumer guarantees nor Federal financial assistance would be necessary. Of special interest may be the list of reasons why the authors of the Decision considered federal financial assistance undesirable (see Appendix A: Decision, p. 122). Alaska was assumed by the Decision authors to be among those entities which would bear the entire noncompletion risk, although the major portion of the risk was assumed to be borne by the project sponsors as equity capital investors.

II. Natural Gas Policy Act of 1978

The Natural Gas Policy Act of 1978 embodied three provisions with substantial impacts on the Alaska project. First, it fixes the wellhead price of Prudhoe Bay gas under Sec. 109 at \$1.45 per MMBtus as of April 20, 1977, subject to escalation for inflation. Sec. 109, however, leaves open the possibility of later wellhead price adjustment by the Federal Energy Regulatory Commission. Second, it provides

that Prudhoe Bay gas will remain regulated after January 1, 1985, when certain other categories of gas are now scheduled for deregulation. Third, the Act allows the rolling-in or averaging of the price of Alaskan gas, including transportation and related costs, with the prices paid by U.S. pipelines for gas from other sources. This provision establishes, in effect, a cushion for higher priced Prudhoe Bay gas, making it seemingly more marketable.

III. Agreement Between Alaskan Northwest Natural Gas and the State of Alaska, April 1978

In April 1978, Governor Jay Hammond and Alaskan Northwest Chairman John McMillian jointly signed a State-Northwest agreement in which Northwest agreed to do several, including the following which bear on state participation in financing and pipeline financing: (1) The Partnership agreed to support before the Federal Energy Regulatory Commission (FERC) gas pricing that (a) "adds on" conditioning costs to the wellhead, (b) defines "old-gas" as only that from the Prudhoe Bay pool, (c) allows rolled-in pricing for Prudhoe Bay gas, and (d) sets a minimum \$1.45 mcf price (escalated) for Prudhoe Bay "old" gas. (The Partnership, however, opposed "added on" conditioning costs in the FERC proceedings); (2) The Partnership will pay the State's reasonable expenses to be incurred for financial and related analyses made to evaluate and/or implement the State's plan to participate in financing the project. The Agreement carried no provisions for State actions.

IV. Cooperative Agreement for Design and Engineering of Alaska Gas Pipeline and Conditioning Plant, and Joint Statement of Intention

The next major document with essential implications as to pipeline financing was the June 1980 Cooperative Agreement and the accompanying Joint Statement of Intention of June 19, 1980. The Agreement outlined the terms and conditions under which the Northwest partnership and the Prudhoe Bay gas producers (Exxon, Arco and Sohio) were to participate in the design, engineering, construction planning, data gathering and cost estimating of the gas pipeline and the gas conditioning facilities for the project segment inside Alaska.

Under the terms of the Agreement, the State of Alaska was given a non-voting seat on the Design and Engineering Board which was to govern the expenditures of the group. Also the State could designate a Project Advisor to the group's Technical Committee. The State, however, was not to contribute

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any capital funds with respect to the work undertaken pursuant to the Agreement, and, accordingly, would not acquire any ownership rights to the design and engineering information developed. Under Sec. 13.7, "Commitments", the State agreed to continue "its study of forms in which it may participate financially in the pipeline, plant or both. The State may elect to pursue its present intention to develop a plan for financing the plant within the time frame of this Agreement." Originally, the Agreement was scheduled to expire July 1, 1981. It has since been amended to provide for its continuation on a quarter-by-quarter basis.

The accompanying Joint Statement of Intention, not signed by the State of Alaska, made clear that the Cooperative Agreement was necessary to "move forward in surmounting the acknowledged difficulties presented by this project" by expediting design, engineering and cost estimation. By January of 1981, the Design and Engineering Board had authorized over \$90 million in expenditures.

V. Alaskan Northwest's May 21, 1981, Letter to Secretary Edwards and Associated Materials Describing the Conceptual Approach Underlying the ANGTS Financing Plan.

Approximately a year after work on design, engineering and cost estimates was initiated under the direction of the Design and Engineering Board, the Northwest partnership presented an ANGTS financing concepts plan for the Alaska segment to Energy Secretary Edwards and others. The concepts included the following:

1. The "as spent" cost of the Alaskan pipeline will be \$21 billion, with another \$6 billion allocated for the conditioning plant. In addition, a pre-committed completion assurance pool of \$3 billion will be formed.
2. Debt/equity ratio remained 75:25.
3. Investment limits were defined as \$5.25 billion in equity for the transmission companies; \$2.25 billion in equity for the gas producers; and with responsibility by the producers for arranging debt up to \$6.75 billion and responsibility by the transmission companies for arranging debt up to \$15.75 billion.

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4. Northwest partners will own 70% of the pipeline and plant, and the producers 30%. Equity commitments to the completion assurance pool will be made on the same 70:30 ratio.

5. Debt funds for both pipeline and conditioning plant will be sought on a project credit basis.

6. Each company's participation will be subject to satisfaction of certain conditions, including inclusion of the conditioning plant as part of the Alaska segment of ANGTS; limitation of each company's investment to a sum certain defined in the financing plan; issuance of firm commitments by all debt and equity participants, acceptable to all other participants, prior to construction of the pipeline or plant; issuance of all necessary governmental authorizations; assurance to all parties that the project is economically viable; assurance to all parties that the Canadian segment will be financed and completed without U.S. company involvement; and equal terms and conditions for each financing layer.

The descriptive backup information contained the following argument regarding project economics:

"A key to why the ANGTS represents America's best energy bargain lies in the downward slope of the ANGTS delivered real cost of gas over time. Each year that ANGTS operates it will move gas more economically than the year before.

No other energy project can promise a year-by-year reduction in energy cost; but ANGTS will produce this result because of one, fixed constant dollar wellhead prices and, two, transportation costs are a high portion of delivered cost and because of the operation of its FERC-established tariff which requires that transportation costs be reduced annually as depreciation charged to operating cost returns original investment and thus reduces the subsequent years' rate base upon which transportation charges are calculated" (p. 4).

At this time the Alaska segment was estimated to cost \$8.3 billion in 1980 dollars, plus an additional \$3.5 billion in 1980 dollars for the conditioning plant. Financing and construction of the two Lower 48 segments, known as the Western U.S. leg and the Eastern U.S. leg, were already underway.

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In the discussion of financing in this document, only short mention is made of possible State participation (p. 88): "The President's Decision envisioned participation in the financing of the project by the State of Alaska. Any debt financing provided by the State of Alaska, or other Alaska governmental bodies, would act to reduce the funding required from other sources."

V. Waiver of Law Package

The next major set of documents with financing implications is the waiver of law package introduced by President Ronald Reagan to the U.S. Congress on October 15, 1981. Reagan reiterated his support for completion of the ANGTS project "through private financing." The purpose of the waiver package, according to the President, is "to clear away governmental obstacles to proceeding with private financing of this important project."

If approved by the Congress, the waiver package would accomplish the following: (1) allow producer participation in equity financing provided certain anti-trust issues are appropriately addressed by FERC; (2) clearly include the gas conditioning plant as part of the approved transportation system; (3) provide for the commencement of billing to consumers in advance of system completion and commissioning of operation; (4) eliminate the possible interpretation that the Natural Gas Act requires an evidentiary hearing on each application for a certificate of public convenience and necessity to construct or operate any segment of ANGTS; and (5) limit FERC's ability to change any rules or orders regarding tariffs which might impair recovery of debt service.

VI. Statements of representatives of Bank of America, Morgan Guaranty Trust Company of New York, Citibank, and Chase Manhattan Bank.

During the Congressional hearings on the waiver package, representatives of the four above-mentioned banks testified on the pipeline project. They were requested by Northwest to review the financial concepts plan Northwest proposed (See IV). The testimony of H. Anton Tucher, Vice President, Bank of America was typical. Tucher stated the bank is presently identifying independent consultants to help evaluate marketability of Alaska gas, capital cost estimates and construction programs, and adequacy and deliverability of gas reserves.

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The three areas analyzed to date were:

(1) likely availability of debt market funds in amounts commensurate with the project's large size. They found the project's debt requirements "are likely to test the limits of the world's capital markets."

(2) proposed financing structure presented by Northwest. They concluded that the project could be financed only if lenders were assured that creditworthy parties had undertaken to assume or repay the project debt in event of noncompletion of the project by an agreed upon date. "Creditworthy" meant parties with the financial capacity and incentive to assure timely project completion, or failing that, with the financial capacity and obligation to either repay or assume the debt in the event of non-completion.

(3) the waiver package. According to the banks, the three key aspects are producer ownership participation, billing commencement date, and authority to modify or rescind orders. Tucher concluded, "I cannot emphasise enough that without approval of these waivers, private financing for the project is not possible. On the other hand, I cannot tell you that approval of the waivers will assure private financing for the project."

The banks will continue their analyses with investigations into the technical, economic, financial and regulatory feasibility of completing the whole system.

In addition to being unnecessary, Federal financial assistance for this project is considered undesirable for the following reasons:

1. Serious questions of equity result from the transfer of risks to taxpayers, many of whom are not gas consumers or will not receive additional gas supplies as a result of the Alaskan project.
2. Federal financial support substitutes the Government for private lenders in the critical risk assessment function normally performed by private lenders.
3. A subsidy in the form of lower interest rates yields an artificially low price for gas.
4. The incentive for efficient management of the project is reduced.
5. The Government is placed in conflicting roles as guarantor and as regulator of the project.
6. Providing unnecessary Federal assistance to this project would set a precedent with respect to other large energy projects that is misleading and counterproductive.

Variable Rate of Return

Since the tariff will require gas consumers to pay for

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BILLIG, SHER & JONES, P. C.

SUITE 300

2032 K STREET, N.W.
WASHINGTON, D. C. 20006

TEL. 202 723-8170

CABLE 8-5-0

TELEX 82-582

JACOB P. BILLIG
TERENCE D. JONES
STANLEY D. SHER
DAVID E. JOHNSON
JOHN H. ATTANASIO
MARC J. FINE
MILTON E. BARRER, JR.
THOMAS E. MANNINGALE, JR.

September 12, 1979

MEMORANDUM

ANGTS
gasline file

RE: FERC Order, August 6, 1979,
-- 1260 PSIG Operating Pressure

A. Introduction

This memorandum will address the question of whether the 1260 psig maximum allowable operating pressure approved by FERC in its August 6, 1978 Decision in Docket No. CP78-123, et al., Alaskan Northwest Natural Gas Transportation Co. -- Pipeline and Capacity (hereinafter FERC opinion) was in effect mandated by the President's Decision 1/ so as to preclude FERC from exercising its independent discretion in deciding this matter. 2/ After a comprehensive review of the Decision and numerous other relevant materials, it is concluded that, notwithstanding comments to the contrary by FERC in its August 6, 1978 opinion, nothing in the President's Decision required FERC to reach its 1260 psig conclusion or suggests a predisposition by the President toward that pressure which would have required FERC to give it more weight than any other one. To the contrary, the Decision expressly indicates that the question of the optimal operating pressure should be a subject of further study and recommendation by a joint U.S. and Canadian technical study group before any decision is made by FERC with respect to this matter.

1/ Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaskan Natural Gas Transportation System (September, 1977). Reference herein to this Decision includes also its accompanying Report.

2/ At page 7 of its opinion, FERC concluded that "absent evidence as to a need for increased capacity, the President's Decision creates a presumption that the operating pressure should be 1260 psig."

A subsequent memorandum from this office will deal with the implications which this disparity between the FERC 1260 psig finding and the President's Decision may have for seeking reconsideration by the FERC of its August 6, 1978 conclusion or for securing a court finding that the FERC Decision in this matter constitutes reversible error.

B. Disparities Between FERC
Order And The Decision

In setting the design specifications for the Alaskan segment of the pipeline at a 48-inch diameter size and a 1260 psig maximum allowable operating pressure, FERC stated that the President's Decision --

. . . decided that the diameter of the pipeline will be 48 inches. Moreover, the Decision creates a predisposition that the 1260 psig system is the one authorized by the President and the Congress, by stating that the "facilities approved and subject to the provisions of ANTA are those included in the revised Alcan filing submitted to the Federal Power Commission (FPC) on March 8, 1977." 3/ (Emphasis added.)

The foregoing finding by FERC that the facilities included in the revised Alcan filing of March 8, 1977 were "approved" by the Decision is not accurate. The actual language of the portion of the Decision referred to by FERC reads as follows:

This section identifies the facilities for the Alcan project which will be entitled to the expedited authorization process prescribed in Section 9 of ANTA. The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcf/d and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC on March 8, 1977. (Emphasis added.) 4/

3/ FERC Order at 3.

4/ Decision at 13.

As seen, the Decision does not state that the subject facilities are "approved", but merely designates those facilities for the expedited authorization process prescribed by ANCTA. 5/ In this respect, the Decision identifies those facilities adequate for a throughput of 2.3 bcf/d and further notes that they are included in the Alcan filing. Further, the emphasis in this portion of the Decision relied upon by FERC is solely on the throughput capacity -- the pressure of the system is not mentioned or identified.

There is substantial discussion of the pressure of the system in other parts of the Decision which was apparently ignored or overlooked by FERC. In this respect, the Decision notes that the Agreement on Principles between the United States and Canada "provides for a jointly conducted testing and evaluation program to determine which system would offer the highest degree of safety, reliability and efficiency. Upon completion of the testing program, the respective regulatory authorities of each country will make a final decision as to which type of system might be installed in each country." 6/

While it is true that much of the discussion in the Decision with respect to the joint study is concerned with the pressure of the pipe to be installed in the Canadian segment, the Decision clearly indicates that this factor was left

5/ Alaska Natural Gas Act * 1976.

6/ Report accompanying Decision at 185. The Agreement on Principles between the United States and Canada specifically provided in this respect that --

The Governments will establish a technical study group for the purpose of testing and evaluating 54-inch 1120 psi, 48-inch 1260 psi, and 48-inch 1680 psi pipe or any other combination of pressure and diameter which would achieve safety, reliability and economic efficiency for operation of the Pipeline. It is understood that the decision relating to pipeline specifications remains the responsibility of the appropriate regulatory authorities. See Decision at 62.

open with respect to the Alaskan segment as well. Thus, as noted above, the Decision acknowledges that the joint study prescribed by the Agreement on Principles relates to "which type of system might be installed in each country." (Emphasis added.) 7/ The following comments made in the Decision also show that the psig for the Alaska segment was considered to be an open item:

In addition, if a 1680 system is installed south of Whitehorse, consideration will be given to installation of a 1680 psi system in Alaska, perhaps with a pipe diameter less than 48 inches. The higher pressure system is generally more economically efficient than lower pressure design. (Emphasis added.) 8/

* * * * *

However, if Alcan increases pressure to 1680 psi, either for the Alaska segment of its line alone or for sections in Canada, additional value design evaluation will be necessary. (Emphasis added.) 9/

The foregoing references clearly contradict the conclusion of a predisposition in the Decision for a 1260 psig. If that were the case, the above comments cited from the Decision would be meaningless. Moreover, as seen, the notion that the Decision contains a predisposition toward a 1260 psig would be contrary to the scheme contemplated by the U.S. - Canadian Agreement on Principles which stipulated that this technical matter should be the subject of eval-

7/ Decision at 185.

8/ Decision at 184.

9/ Decision at 190.

uation and testing by the joint study force to be created pursuant to that Agreement before any final decision is made. In this respect, while the Decision indicated that there was a "likelihood" that a 48-inch 1260 psig line would be installed in Alaska, the final decision regarding this issue was to be made by FERC and its Canadian counterpart on the basis of the study group's findings. 10/

In point of fact, a joint recommendation by the study group was never made. The U.S. representatives recommended a 48-inch 1680 psig pipeline for the Canadian segment while the Canadian representatives advocated a 56-inch 1080 psig system. 11/ Prior thereto the U.S. representatives had re-

10/ See, Decision, pp. 260-261, which provides as follows:

Subparagraph (a) establishes a joint technical study group for the purpose of evaluating the relative merits of the larger diameter and higher pressure systems which have been suggested, as well as any other combinations of pressure and pipe size which might achieve objectives of increased efficiency. The 48-inch, 1260 psi which was proposed by the applicant and will likely be installed from Whitehorse north to Prudhoe Bay field will also be evaluated by the group. Final decisions based on the results of the testing program will remain the responsibility of the respective regulatory authorities in the two countries. (Emphasis added.) (Decision, pp. 260-261.)

11/ Notice of Delegate Report and Order Inviting Comments, Docket P78-123, issued May 17, 1979 pp. 2-3.

commended a 48-inch 1680 psig system for the Alaskan segment as well, in view of the possibility of additional reserves. 12/

The fact that the psig was left open by the President's Decision is further seen from its discussion of the potential need to increase the capacity of the line 13/ to accomodate possible additional possible reserves. The FERC decision itself states that this possibility makes what it previously had found to be a Presidential "predisposition" a "rebuttable one." 14/ However, FERC then goes on to make it appear that increased compression is the only means by which the Decision contemplated additional reserves should be handled, implying that an increase in psig was not considered. Thus, the FERC opinion states that --

12/ Despite Canada's decision the United States Department of transportation continued to recommend the 48-inch 1680 psig system for the Alaskan segment. In the "Report Of The Alaskan Delegate on the System Design Inquiry", the DOT:

. . . argued that all the technical and economic data appear to them to support building a 1680-psig system. Moreover, the availability of capacity resulting from the construction of 1680 psig system would encourage development and exploration in the total North Slope area. Citing a February, 1978 Tehnical Study Group evaluation of the 1680-psig system, DOT argued the system could be build and operated safely and reliably. Report of the Alaskan Delegate on the System Desig Inquiry, supra, pp. 17-18. (Decision at 193.)

13/ The only other connection in which psig is discussed in the Decision is with respect to capital costs incurred in Canada. Significantly, this discussion cites capital costs for a 48" 1260, as well as a 1680, psig line, in addition to a 54" 1120 psig line. (Decision, p. 77.) It was also noted that the discussion of these Canadian capital costs excluded any increases in costs attributable to a number of factors, including the gas conditioning plant construction. (Decision, p. 79.)

14/ FERC Decision, p. 4.

The President's Decision also stated that the capacity of the system should be adequate for an average daily throughput of up to 2.4 billion cubic feet per day (Bcfd); and with increased compression, capable of increasing to an average daily capacity of 3.2 Bcfd." 15/

In fact, increasing psig to 1680 was clearly another alternative mentioned in the Decision for expanding the capacity of the system. For example, the Decision states --

If a 1680 system is installed
The system would have lower fuel and operating expenses than a 1260 system but the savings would not be quite sufficient to offset carrying charges on the increased capital outlays. On the other hand, the system does provide a large amount of inexpensive expansibility that could be used in the event significant new finds of natural gas are made in Alaska. 16/

Further, the Decision ultimately concludes that additional compression is not a desirable means to provide for the need for future increases in capacity, and that from a cost standpoint the more desirable alternatives are increasing the diameter or working pressure of the pipe.

It was also suggested in the safety and design report that for economic reasons, Alcan should consider increasing the operating pressure and wall thickness of its 48 inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources.

* * * * *

15/ FERC Order at 4.

16/ Decision at 166.

Compression requires fuel essentially in proportion to the horsepower added. Thus, as more throughput is required in an existing pipeline, horsepower (capital cost) and fuel use (operating cost) will increase.

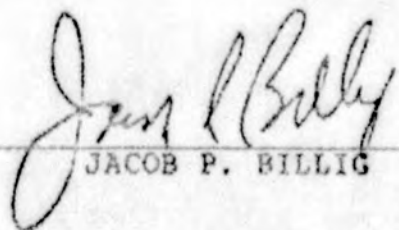
(Footnote: Horsepower and fuel requirements increase roughly as the difference between the squares of the relative throughputs. Doubling the throughput would require about 4 times as much fuel.)

* * * * *

. . . Overall, considering the artie construction, inflationary impacts, and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughput would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline. 17/

C. Conclusions

Based upon the foregoing, it is apparent that FERC erred in finding that the Decision contains a predisposition for the 1260 psig for the Alaskan segment. It further appears that this erroneous finding was substantially responsible for FERC's ultimate conclusion in its August 6, 1979 report that the 1260 psig proposed by Alaska Northwest Natural Gas should be approved.


JACOB P. BILLIG

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THE STATE OF ALASKA ROYALTY OIL AUCTION:
COMMENTS AND RECOMMENDATIONS

Tanzer Economic Associates, Inc.
Second Draft
November 19, 1980

The State of Alaska Royalty Oil Auction:
Comments and Recommendations

This report lays out some suggestions on the possibility of auctioning off a portion of the state's royalty oil rather than taking payment from the Prudhoe Bay oil producers for the value of the oil. We believe that the state could do well in such an auction, and certainly better than it would by continuing to take this oil in value. Furthermore, we believe that the state should move forward as quickly as possible to hold such an auction.

The report is divided into two parts. The first part discusses the advantages of auctioning the oil over taking the oil in value. The second part examines the state's proposed "Invitation to Bid on State of Alaska Royalty Oil."

Part I Advantages to the State of a Royalty Oil Auction

The State of Alaska is entitled to 12.5% of all the oil removed or sold from all state oil leases in the Prudhoe Bay field as a royalty. At present this amounts to 187,500 barrels per day. The state is planning to auction off 45% of this royalty oil or 84,375 barrels per day.

It seems to us that there are two main goals in holding such an auction. First, to get more revenue for the state than it gets under the present system. At present the state receives from the Prudhoe Bay producers for its royalty oil "in value" money payments based essentially on the average per barrel price of Prudhoe Bay oil reported by the producers. Second, to use as some yardstick to try to determine whether in fact the prices reported by the companies for the "value" of Alaskan crude oil are true market prices, or are artificially depressed.

With regard to the increased revenue goal, there are three major factors which lead us to believe the state could obtain a higher price from a crude oil auction than it could get from taking its royalty in money.

These are:

- 1) The "underreporting" effect -- based on the fact that the companies have a very strong incentive to report to the state artificially low prices for crude oil which are below true market prices.
- 2) The "security of supply" effect -- based on the fact that assured supplies of crude oil have a value to refiners greater than even "true" market prices.
- 3) A possible "location" effect -- based on the fact that the companies report to the state an (adjusted) average price based on the prices paid by refiners near and far from Alaska, while in theory the state auction would be most attractive to refiners near to Alaska who could normally pay higher prices.

The rest of Part I discusses the possible impact of these factors.

Underreporting of Market Prices
by Prudhoe Bay Producers

The first reason the state might reasonably expect from an auction a higher price than the in value payments is that all of the bidding companies know that the Prudhoe Bay producing companies have a strong incentive to report to the state "market prices" for Alaskan crude oil which are lower than real market prices. Historically, this has been because the combined state royalty and severance tax rate of almost 25% has made it profitable for the companies to shift their Alaskan profits from the crude oil production sector to their refining, transport and marketing divisions out of the state.

For example, one mechanism for the companies to shift their profitability would be to report fictitiously high tanker rates, thereby depressing the wellhead value. Another way would be to report fictitiously low crude oil sales prices, either by reporting sales within a company at arbitrary prices, or by working out deals with other companies for selling them Alaskan crude oil at below market rates in exchange for "swaps" in other places at below market rates. While this incentive has presumably operated in the past, the incentive to shift profitability away from the crude oil sector has been enormously increased by the federal windfall profit tax on oil, which came into effect in March of this year.

Basically, the "Crude Oil Windfall Profit Tax Act of 1980" provides that 70% of any company profits on crude oil production, above a relatively low base price level, must be paid to the federal government as a windfall profits tax. Of the remaining 30%, presumably with a normal 46% corporate income tax rate, the company is left with only 16% of the incremental profitability on Alaskan crude oil sales. A recent Business Week story on Tosco Corp. describes the implications as follows:

"U.S. tax policy seems likely to bring on a dramatic shift in the pricing policies of the integrated oil companies, from which independent Tosco buys much of its crude. Under the new windfall profits tax, wellhead oil revenues are taxed up to 85%, while refining profits carry only the standard corporate tax rate. Big oil producers will thus be encouraged to sell their crude at artificially low prices in the U.S. while beefing up their refinery margins. This trend is already beginning to show up, Winston (Tosco President) believes."¹

Note also that because of Alaska's combined royalty, severance and income tax rate, the incremental tax rate on crude oil profits is even greater. Assuming roughly an effective 31% combined Alaskan royalty and tax rate, from \$1 of gross crude oil

profits this would leave \$.69 profits, and after deduction of the windfall profits tax plus the federal income tax, this would leave \$.08, or implying for Alaskan oil a 92% combined state/federal tax rate on incremental crude oil profits; this would compare with possibly a tax rate below 50% for refining operations in states which have little or no corporate income tax rate (or where the operations may have piled up a loss for one reason or another, e.g. from earlier times when products were sold if necessary at losses in order to capture crude oil profits).

The key point about these very powerful incentives for the Alaskan producing companies to report fictitiously low or artificially low wellhead prices is that all of the refiners who would potentially bid at the state auction know that this is going on (because they are all active in the oil market trying to buy oil and can compare what the companies report to the state with their own experience). Thus, these companies know that the average reported price by the producing companies will be below the true market price, and this alone allows them to bid above the reported "in value" price without taking any risk at all.

Security of Supply

The second major reason the state might expect bids higher than the "in value" price is the security of

supply factor. There is ample evidence that in today's world assured crude oil supplies have a greater value to refiners than their market price. One piece of evidence is the very high bid made by refiners like Amerada Hess to the state for the right to explore for crude oil in the recent Beaufort Sea Lease Sale. Even more dramatic evidence is provided from China, where major oil companies from all over the world, including some Alaskan producing companies, have undertaken seismic work at their own cost (which must be provided to the Chinese government) solely for the right to be considered to be allowed to bid for exploration drilling rights; moreover, if a company does win the right to drill for exploration, it will put up all the capital and technology and take all the risks and in return it will get if successful only the right to buy part of the oil produced at world market prices!

The value of Prudhoe Bay crude as a secure source of supply has been aptly pointed out by the Oil and Gas Journal:

"The question then arises: Will (Prudhoe Bay) crude be as salable when fully decontrolled as it is today?

The answer, by virtually all sellers and buyers, is yes.

The reason lies in market demand for an assured supply of oil, competitively priced.

Prudhoe Bay represents this assured supply for many years to come-in contrast to

uncertain deliveries from overseas, where political conditions can bring a sudden shutdown.

Also, West Coast refiners have learned, during 33 months of experimenting, to use crude of Prudhoe Bay characteristics far more than they anticipated when the field begin production in July 1977."²

The basic reason that assured crude oil supplies have a normal "value" greater than market price is that without those crude oil supplies, refiners and marketers in times of shortages face the real danger of either having to pay enormous premiums in the "spot" market (premiums over longer run contractual prices), or else go without crude oil, which means sharp reductions in the profitability (or even losses) of their refining and marketing operations. Particularly in refining, where there are enormous investments profitability is highly sensitive to the level of capacity operated at, and an inability to get crude oil can easily turn large profits into large losses.

By way of example and illustration, assuming refinery investments on the order of \$5,000 per daily barrel of capacity, if refineries are to cover even a marginal pre-tax profit rate of 20% on investment plus 5% depreciation, they must generate \$1,250 in cash flow

per year for each barrel of daily capacity. Thus, the cash flow necessary to cover these capital charges amounts to about \$3.50 per barrel. This is one measure of the premium that a refiner under these assumptions would be willing to pay rather than to be shut out of crude oil, and not be able to operate the refinery.

Location Effect

The third reason that the state might expect to receive a higher price from an auction is the average price the companies report to the state for crude oil purchases represents an average based roughly on two barrels of oil going to the West Coast of the United States and one barrel of oil going a much longer distance to the Gulf of Mexico.

In theory, a refiner who is on the West Coast of the United States would be willing to pay a higher wellhead value for Alaskan crude oil than a Gulf and East Coast refiner, because of the lower shipping cost from Alaska to California's West Coast. Hence a state auction for a relatively small amount of oil, e.g., 85,000 barrels per day, should attract great interest from West Coast refiners who would be willing to bid a higher price because the value of Alaskan oil to them is greater than to Gulf and East Coast refiners.

By way of analogy, presumably the average reported price by the companies to the state consists of the price of a bottle of milk which is two parts cream (West Coast sale) and one part skim milk (Eastern Coast sale). By way of an auction the state can get bids solely on the cream rather than having to accept an average price for milk. By way of rough quantitative example, if there is an average transport differential between the West Coast and Eastern Coast of \$3 per barrel,³ everything else being equal, West Coast refiners would be willing to pay \$3 per barrel more than Eastern refiners. With two-thirds of the crude oil going to the West Coast and one-third to the East, this would mean that the companies average reported price for Alaskan oil would be \$2 greater than the Eastern prices. However, the West Coast refiners who would bid in the state auction would be willing to pay \$3 more than the Eastern refiners, so that the state would thus be assured of getting \$1 per barrel more than the average reported price.

However, due to the methodology that the state uses in calculating in-value prices for the purpose of royalty collection, the location effect has less than half of the impact indicated by our hypothetical example. This is because in-value prices are calculated in a way which reduces the influence of producers who report lower than average wellhead prices (see table 1). Specifically,

each producers own weighted average price is calculated. Then, for each producer, the weighted price of all other producers is calculated. Finally, the highest of these two prices is taken as the applicable price for the calculation of royalties from each producer, and these applicable prices are themselves averaged, based on quantities produced by each producer. In our example, the locational effect works out to about 44¢ per barrel. Finally, the preceding analysis of the location effect is based on the simplifying assumption that the price of Alaskan oil in different locations differs only by its relative transport costs from Alaska. This obviously ignores the many supply/demand factors which affect oil prices in different regions, and as such it oversimplifies the problem. Nevertheless, this type of analysis is useful for indicating the possible order of magnitude of any tendency such as a location effect.

Combined Effect of the Three Factors

To illustrate quantitatively the possible cumulative impact that the three different effects discussed earlier might have on what the state could realize from a crude oil auction, versus what it would get from taking royalty oil in money, we use the following hypothetical values. Assume that the average wellhead value reported to the

TABLE 1⁴

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The "Location" Effect on the Average
Reported Price of Prudhoe Bay Oil

Producer	Delivery Point	Quantity Produced and Delivered	Wellhead Price	Weighted Average Price of All Other Producers	Applicable Price
A	West Coast	24 barrels	\$24		
	Gulf and East Coasts	0	0		
producers weighted average price, producer A			\$24	\$22.69	\$24
B	West Coast	26 barrels	\$24		
	Gulf and East Coasts	26	\$21		
producers weighted average price, producer B			\$22.50	\$23.56	\$23.56
C	West Coast	17	\$24		
	Gulf and East Coasts	7	\$21		
producers weighted average price, producer C			\$23.12	\$22.97	\$23.12
actual weighted average price of all producers			\$23		
adjusted weighted average price of all producers					\$23.56

Note: Example based on 67 barrels going to West Coast, 33 to East Coast. Producer A has 24% of supply, B 52%, and C 24%. All crude going to West Coast has a wellhead price of \$24 per barrel. To Gulf and East Coast \$21 per barrel.

state (for decontrolled oil) is \$25 per barrel. Assuming an "underreporting" effect of \$1 per barrel, the state might then expect to get \$26 per barrel.

Assuming a "security of supply" effect of another \$1 per barrel, the state might expect to get \$27 per barrel. Finally, assuming a location effect of \$.50, the state might expect to get \$27.50 per barrel. In sum, the state might ultimately expect to receive 10% more than the \$25 per barrel it would get based on the average price reported by the companies to the state. If the state auctions 85,000 barrels per day for 1 year, this amounts to 31 million barrels of crude oil, and the additional income would be almost \$80 million. (Moreover, it would raise strong doubts about the realism or usefulness of "market prices" reported by the companies to the state.)

In conclusion, we believe that within a very broad range of possible supply/demand situations in world crude oil markets the combined impact of the underreporting, security of supply and locational factors will insure that the state will gain at least some additional revenues from an oil auction. It is worth noting the results of some recent U.S.

Government auctions of Western crude oil, as a possible guide to the gains from auctions in both boom and slack periods.

In California, the U.S. Government annually auctions off crude oil from the Naval Reserve at Elk Hills. In December, 1979, Phillips Petroleum bid \$11.12 per barrel above the posted price, for a one year contract of 10,000 b/d of oil. In general, bids at that auction were \$3 to \$5 above posted prices (see table 2). This sale occurred during a time of strong demand for oil. In the previous 1978 auction, which came at a time of slack demand, winning bids averaged less than \$1 per barrel above posted prices.⁵ Similarly, a U.S. Government auction held in January 1980 for crude oil from the Teapot Dome field in Wyoming brought bids of up to \$7.50 per barrel over posted prices; the Teapot Dome auction in 1978 drew bids averaging about 65¢ above posted prices.⁶

TABLE 2

High Bids in Elk Hills Sale* (December, 1979)

Company	Bonus above posting (\$/bbl)	Volume (b/d)
Phillips	11.12	10,000
Fletcher	7.34	2,000
ARCO	5.32	15,000
Oasis Petro Energy	5.23	21,000
Mohawk	5.03	11,095
Pacific Refining	5.02	20,000
C. Itoh	4.82	10,793
Howell	4.47	3,200
Southwest Petrochem	4.26	4,000
Marathon	4.05	2,000
South Hampton	4.03	2,500
Beacon	3.95	3,020
Powerine	3.76	10,000
Mobile Bay	3.67	3,900
Union	3.65	4,300
Langham	3.52	250
Newhall	3.50	2,200
Sabre	2.84	1,000
USA Petrochem	2.68	1,120

*Preliminary results, subject to correction.

Source: Oil and Gas Journal, December 31, 1979, p. 54.

Part II Comments on the State's Proposed Document,
"Invitation to Bid on State of Alaska
Royalty Oil"

The comments here on the state's proposed "Invitation to Bid" focus on key procedures for which we suggest changes. Each subheading in this report refers to the paragraph and subject heading from the state document.

(1) Date of the Auction

The state has proposed that bids be received no later than December 18, 1980. We recommend that the date be set somewhat later, due to the fact that the OPEC oil minister's meeting will officially be held on December 15-16 and may extend several days beyond that.

As a result of the OPEC meeting there may be changes in the world's perception of the crude oil situation as well as the price of oil. Since such changes would affect buyers' bid at an auction, it would seem best to allow prospective bidders some time to digest the implications of the OPEC meeting. This could help reduce the general level of buyers' uncertainty about the future. Reducing the level of uncertainty for bidders should have a positive effect on bids, and state revenues, basically because uncertainty tends to lead to cautious and conservative assumptions about the future. (We have discussed this phenomenon as

it relates to an analogous situation, cash bonus bidding for exploration leases, in our earlier report on "The Beaufort Sea Oil Lease Sale".⁷⁾ Additionally, it would seem more equitable to the bidders to allow them to make their decisions on the basis of as much information as possible.

(2) Paragraph 2: Lots

The state's current proposal calls for the oil offered to be divided into 17 lots each consisting of roughly 2.6% of Prudhoe Bay royalty oil or 4,960 barrels per day (b/d) of oil (assuming total production from Prudhoe Bay of 1,500,000 b/d).

In theory, the state's total available amount of royalty oil could be auctioned off in many different ways. These could range from a "winner take all" system under which one company (or group of companies) would get all the oil, to a system under which the total oil would be divided into smaller lots, e.g., 1,000 b/d, and as many as 85 companies could be winning bidders.

Our belief is that the state's revenues might best be maximized by a different type plan, which would allow each company to bid for exactly the amount of crude oil

it desires. The total quantity available would then be awarded to bidders on the basis of the highest bidder first getting its desired amount of oil, the second highest bidder getting its desired amount, etc. until all the oil was gone. (To accommodate bidders who were not interested in small quantities of oil, a bidder could be allowed to set a minimum quantity that it desired at its bid price.)

We see two basic advantages to this approach. First, it would give companies a chance to fill their exact crude needs, without requiring them either to bid for less oil than they want, or to form groups to bid for the round lots offered or to resell the undesired quantities of oil -- all of which steps involve undesirable costs and risks that will tend to reduce the bid prices companies would be willing to pay. For example, if the lots are divided into units of roughly 5,000 b/d, and a company wants 7,000 b/d, it faces the choice of bidding for only 5,000 b/d, or finding a partner which wants 3,000 b/d enabling it to bid for 10,000 b/d, or bidding for 10,000 b/d and gambling on its ability to resell 3,000 b/d in the future. Presumably all of these choices are less than optimum for the company, and this should tend to make the company unwilling to pay as high a price for either 5,000 b/d or 10,000 b/d as it would pay for 7,000 b/d.

The second reason for allowing "specific bidding" is that it could attract bids from smaller independent refiners, who have little or no crude oil of their own, and who thus have even greater needs for security of supply than bigger refiners. Therefore, presumably these smaller refiners would be willing to pay a higher price than larger companies for the state's oil. (This tendency might be reinforced by the fact that the smaller refiners do not have national or international networks of crude oil contractual arrangements which might be jeopardized by "bidding too high".)

Evidence of the important role that bids for relatively small quantities can play in maximizing auction sale revenues can be seen from results of the December 1979, Federal Elk Hills Auction (See Table 2). Of the 19 winning bids, 12 were for less than 5,000 b/d (including one for only 250 b/d), and these 12 combined accounted for almost one-fourth of the total volume auctioned.⁸

We would also argue that insisting on lots of the magnitude of nearly 5,000 b/d would discourage the bidding of small processors within the state who may need

a smaller supply in order to undertake a new project. It has the effect of discriminating against small business. Eliminating these potential smaller bidders could discourage small scale economic development which would benefit the people and the state of Alaska.

(3) Paragraph 3: Term

The state's proposal for the oil to be sold for a term of one year is a good one. This longer period of time is preferable to the 6-month period proposed earlier for at least two reasons.

First, a sale covering a longer period is more likely to increase the number of bidders for Alaskan oil. This is because for a refinery that has not previously been using Alaskan crude oil, there are costs it must incur in order to adjust its equipment to handle such crude oil. Therefore, it would normally be more attractive to such refiner to undertake those investments if its Alaskan crude oil supply was assured for a longer period. Moreover, industry sources we have talked to indicate that an assured supply for one year would normally be sufficient to make a refiner willing to make the adjustment.

Second, a longer term contract would also be more attractive to companies since a large part of their interest in Alaskan crude would be as protection against a serious shortage of crude oil. While at present there is no such shortage, the possibilities of such a shortage are expected to increase as time passes. Hence, the longer the time period covered by the auction sale, presumably the greater the premium oil refiners would be willing to pay for protection against possible future shortages.

We disagree with the provision allowing buyers to terminate their contracts.

First of all, upon termination of a contract the state's income from royalty oil would be reduced. If the oil were to revert back to the producing companies the state would get only the in value price and no premium. If the oil were to be resold by the state to another buyer, the price would likely be lower than the bid in the original auction. This is because the time period of the contract would be reduced, and the competitive conditions, given the termination, would almost certainly be worse.

Secondly, a termination clause is not necessary in terms of equity for the bidders. The bidders would be protected against extreme deviations between the future market price and the price they ultimately pay by the

provisions tying the auction price to the in value price reported at the time of delivery (see discussion on paragraphs 6 and 7). Thus, if market conditions changed sharply in the future, the in value price would change in the same direction.

Finally, a certain amount of risk would have to be expected in any kind of crude oil sale. To eliminate that risk might encourage irresponsible bidding which ultimately could hurt the state.

The Federal government had a similar clause in its regulations for the Elk Hills Naval Petroleum Reserve auction in December 1979. The highest bidder, Phillips Petroleum, the fourth highest, Oasis Petro Energy and the sixth highest, Pacific Refining, all cancelled when it appeared that their bids priced the oil above alternative supplies.⁹ The rules governing the next Federal government sale (December 1980, Kern County, California) contain no provisions for cancellation.¹⁰

(4) Paragraph 6: Price

The state's current proposal establishes the base price to which the premium bid will be added as the reported in value price of Prudhoe Bay oil as computed under the Exhibit B formula the state uses to calculate in value royalties at the time the oil is delivered to the bidder (hereafter referred to as the base price).

This is far superior to using a fixed price as a base and possibly exposing the state to loss of revenue from jumps in oil prices.

The state may wish to consider establishing the base price, to which the bid premium will be added, as equal to the exhibit B reported in value price at time of delivery plus a certain dollar amount which would account for possible additional costs to the state of an auction. This precaution could protect the state against the possibility of receiving less in total for its oil than if it had not auctioned it. For example, Standard Oil of Ohio pointed out in its comments on the auction regulations that if the auctioned oil goes to the West Coast and displaces a Prudhoe Bay producer's oil from the West Coast to the Gulf Coast this could lower the wellhead price for all Prudhoe crude, thus lowering the state's royalties, severance and income tax. If the premium received at the auction is insignificant the state's gain from the auction could be less than its loss of income from the lower wellhead value.

Our preliminary examination of SOHIO's point indicates that theoretically, under certain extreme assumptions, the effect could be significant. Given this possibility the state should be prepared to protect itself against a possible reduction of revenues. As a first step we

recommend that the state government, which has all of the detailed data on previous sales, carefully analyze this effect and estimate what the dollar magnitude might be. Secondly, the state could then use this estimate of the dollar amount to protect itself against any such future loss, by adding it to the base price (i.e., adding it to the future in value price). In effect, then, the state would establish a minimum premium bid.

(5) Paragraph 7: Premium

An alternative to the state's proposed premium expressed as a flat dollar amount in dollars and cents is one based on a percentage of the price defined in paragraph 6. Instead of bidding \$5 over a projected hypothetical base price of \$25, a buyer would bid a premium of 20%. A percentage may more accurately reflect changes in market conditions. The greater the rise in prices the greater the premium received by the state. In terms of equity to the bidder, if future prices were to rise sharply, this would indicate an unexpected scarcity of oil, and bidders would be quite happy just to have access to the crude oil. If prices failed to rise to the levels expected by the bidders, a percentage bid would result in their having to pay a lower premium reflecting the lesser value of the oil to them. In our