SCOMM

#12:6

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

M E M O R A N D U M

April 12, 1977

SUBJECT: Rate of Return Analysis on North Slope Operations and Comparison of Alaskan Oil Tax Rates With Other States (W.O. #4017)

TO: The Honorable John Rader

FROM: Richard G. Haggart
Research Analyst

This memorandum is in response to your request that we analyze recent oil industry testimony before the Joint House-Senate Resource Committee hearings on oil taxation. Specifically, you requested that we examine:

1. Competing statements and claims regarding rates of return that will be, or may be, earned on North Slope operations, in terms of overall accuracy and the appropriateness of underlying assumptions.

2. Whether the relative tax collection rates developed by Exxon and Standard Oil of Ohio for Alaska and other oil producing states accurately reflect current and proposed law.

Because of the complex nature of the issues involved and your need for a timely response because of the Finance Committee hearings on oil taxation beginning April 12, 1977, we have not been able to respond to your request in as full and complete a manner as we would prefer. Consequently, this memorandum includes only the following items:

1. A general discussion of discounted cash flow rate of return analysis and the major issues affecting such analysis, in terms of North Slope operations, and which cause significant variations among different forecasts of rates of return.

2. An appendix in which the specific rates of return cited by Exxon in their testimony of March 24, 1977, are examined for technical and methodological accuracy.

3. A brief analysis, performed in conjunction with the Department of Revenue, regarding the accuracy of Exxon's and Standard Oil of Ohio's statements regarding relative tax rates among oil producing states.

A fourth part of the memorandum is still in preparation and will be submitted to you by the end of April. In part four, we plan to develop a cash flow earnings model of Prudhoe Bay and the pipeline and examine the resulting rate of return from a variety of viewpoints. It is hoped that this analysis will help relieve some of the current confusion surrounding the issue of North Slope profitability and rate of return analysis.

RGH:jm
Attachment

Rate of Return Analysis

The operative concept in modern rate of return analysis is that of the "discounted cash flow". Although there are other and generally older measures of the rate of return (including the "pay-back" method, "accounting return", and a variety of returns on book financial measures), there is general agreement that some form of discounted cash flow or discounted rate of return analysis is the superior method. The essential difference between discounted cash flow analysis and any other method is that DCF analysis takes into account the concept of the "time value of money"--in essence, taking cognizance of the fact that a dollar received today is worth more than a dollar received next year. How much more is, of course, what DCF analysis is all about.

Clearly, in this memorandum, it is not possible to survey all aspects of discounted cash-flow analysis. However, the testimony which has been received by the legislature regarding "Prudhoe Bay rates of return" center around the following major differences of opinion:

1. The amount of money invested in the project. As will be discussed subsequently, it also may be relevant to determine an appropriate definition of "the project", and to note the proportion of borrowed funds to equity funds (debt versus stockholder interests) and in what area of the overall project such investments fall.

2. The relative cost of the investment--either in the form of direct costs, such as interest, or in opportunity costs;

AGO 531130

i.e., how much money <u>could</u> have been earned had not the investment money been tied up in a half-built pipeline.

3. The magnitude, timing and duration of the cash flows from the project--how much oil will be pumped, what price will be received for that oil and over what time period this will all occur.

4. Finally, what costs, including taxes, should be deducted from the cash flows described in #3 above to arrive at a net cash flow figure for each year of production.

Obviously, given the variability of the items listed above, disagreements as to the "real" rate of return are not hard to imagine.

The primary source of disagreement among those testifying before the legislature (whether in 1976 or in 1977) has been regarding the level of investment to consider and whether to include assets financed by debt as well as those financed by equity. The basic and still unresolved questions before the legislature are:

1. Should the pipeline itself be considered separately from the Prudhoe Bay fields, or should the project be considered jointly, when making rate of return calculations?

2. Should the rate of return, whether calculated on an aggregated or disaggregated basis, be a return on net worth (stockholders' equity) or to total invested capital (which includes debt financing)?

In our judgment, differences on these questions account for 90 percent of the differentials among rate of return analyses which have been furnished to the State of Alaska.

TABLE I

FINANCIAL STRUCTURE OF PRUDHOE BAY AND TRANS-ALASKA PIPELINE
JULY 1, 1977
($ Billion)

Project	Debt(%)	Equity(%)	Total(%)
Prudhoe Bay*	$1.48 (40%)	$2.22 (60%)	$ 3.7 (100%)
TAPS	$7.06 (85%)	$1.24 (15%)	$ 8.3 (100%)
Total	$7.93 (66%)	$4.07 (34%)	$12.0 (100%)

* The debt equity ratio of Prudhoe Bay investments is set arbitrarily at 40/60.

TABLE II

HYPOTHETICAL CASH FLOW ANALYSIS
PRUDHOE BAY AND TRANS-ALASKA PIPELINE SYSTEM, 1978-2005

FY Year	Net Cash Flow Prudhoe Wellhead	Net Cash Flow TAPS Pipeline	Net Cash Flow Total Project
1978	$ 894	$600	$1494
1979	$ 920	$600	$1520
1980	$1661	$600	$2261
1981	$1869	$600	$2469
1982	$1869	$600	$2469
1983	$1869	$600	$2469
1984	$1869	$600	$2469
1985	$1869	$600	$2469
1986	$1774	$600	$2374
1987	$1687	$600	$2287
1988	$1518	$600	$2118
1989	$1365	$600	$1965
1990	$1229	$600	$1829
1991	$1105	$600	$1705
1992	$ 939	$600	$1539
1993	$ 800	$600	$1400
1994	$ 679	$600	$1279
1995	$ 579	$600	$1179
1996	$ 491	$600	$1091
1997	$ 393	$600	$ 993
1998	$ 312	$600	$ 912
1999	$ 237	$600	$ 837
2000	$ 185	$600	$ 785
2001	$ 124	$600	$ 724
2002	$ 85	$600	$ 685
2003	$ 59	$600	$ 659
2004	$ 42	$600	$ 642
2005	$ 29	$600	$ 629

It cannot be stressed too heavily that the rates of return calculated using the investment levels in Table I and the hypothetical cash flows in Table II are not the Legislative Affairs Agency's estimates of North Slope rates of return. They are, instead, illustrative models which demonstrate the possible variation in rate of return calculations, using the same data base. The investments are, of course, relatively accurate representations of investment-to-date in various parts of the project, as reported by the owner companies. The cash flows, however, are largely hypothetical and are not the result of any rigorous analysis--nor are they intended to be.

Briefly, the assumptions that went into developing Table II are as follows:

1. Net after-tax value of oil was considered to be $3.25 per barrel at the wellhead.
2. Pipeline net after-tax profits were assumed to be $600 million annually regardless of throughput levels (approximately a 7% return on $8.3 billion invested in the pipeline).
3. Production was assumed to begin in 1977, peak at 1.8 million barrels per day in 1981 and begin declining from that level in 1986. Production ceased in 2005 at a level of less than 30,000 bbl/d.

Using the data in Tables I and II, the following internal rates of return were calculated:

TABLE III

HYPOTHETICAL RATE OF RETURN VARIANCE CALCULATIONS[1]

	Internal Rate of Return (DCF Rate of Return)
Prudhoe Bay:	
Equity:	57.1%
Total:	36.0%
TAPS System:	
Equity:	48.2%
Total:	5.7%
Total System:	
Equity:	46.8%
Total:	16.3%

* Calculated from data contained in Tables I and II of this report.

As can be seen from Table III, the first major difference emerges if the pipeline is excluded from investment and rate of return calculations. Since about 69¢ of each dollar of capital invested in North Slope operations has gone to pipeline construction, and yet produces only about one-third of total cash flows, the net effect of excluding the pipeline is clearly to increase the rate of return on Prudhoe Bay production alone. Thus, excluding the pipeline from the overall calculation increases the DCF rate of return on "Prudhoe Bay" from about 16% over the life of the project to a 36% rate of return.

An even more dramatic change occurs if the return to only the equity investment is considered--here the DCF rate of return rises from 16% on all capital to over 48% if only equity is considered. Finally, the greatest returns are achieved when the two projects are considered separately, and earnings are only attributed to equity interests. The pipeline project's rate of return to equity investment is almost 50% (compared to about 5.7% return on total invested capital), while Prudhoe Bay itself generates a return in excess of 57% if equity alone is considered.

Clearly, these differences are dramatic. They are also so wide-ranging that reconciling them becomes difficult, although not impossible. The following sections discuss some of the major economic and policy issues that cause the different rate of return results and the appropriateness of such differences in terms of the State of Alaska's viewpoint and that of the companies.

Excluding the Pipeline From DCF Rate of Return Analysis

The question of whether or not the pipeline and its associated earnings should be included in the calculation of the North Slope rate of return seems, on balance, to favor exclusion. On the one hand, the federal government limits the return on common carrier pipelines--to include such common carriers with more profitable ventures, so the reasoning goes, simply makes no sense, since by federal law (and court decisions) separate investment, financing and profit decisions must be made for such a project. Thus, to include the TAPS in a rate of return analysis artificially lowers the overall rate by including a regulated, capital intensive project in the determination. Further weight to this proposition is provided if the projects are viewed as engaging in a series of discrete, arms-length transactions, instead of the intra-company transactions of vertically integrated corporations. Thus, if the pipeline were owned by General Motors Corporation, for example, the question of Prudhoe Bay versus pipeline rates of return would never arise--instead, tax and regulatory decisions would be made separately in view of their effects on the owner/operators of the oil field and upon the owner/operator of the pipeline. Only in the most general sense would decisions be reached on the basis of aggregate effects on the two areas (i.e., if you taxed the oil production out of existence, you would also "affect" the pipeline owner).

A final point is that any increased tax burden imposed by the state can be passed through the pipeline system in the form of higher rates. Consequently, any tax increase by Alaska will reduce the overall rate of return for companies operating in the state but will not necessarily reduce the return earned on the pipeline alone (and would not reduce the return, provided the owner/operators make tariff decisions on the basis of arms-length transactions). Thus, inclusion of the pipeline and its rate of return could provide a potentially misleading picture of the impact of taxes upon North Slope rate of return.

In defense of the concept of aggregated rates of return, it is clear such a view is appropriate from the company's as well as investor's viewpoints. After all, Exxon or Sohio cannot sell stock in Prudhoe Bay production and exclude the pipeline--or any other part of their operation. Likewise, investors purchase a piece of the total Exxon or Sohio pie--not just the highly profitable portions.

On balance, however, it seems appropriate for the state to consider the project in its component parts in terms of developing tax policy. A proper understanding of the financial and economic effects of imposing an ad valorem wellhead tax, versus an ad valorem hardware tax, versus an aggregated francise tax, can hardly be achieved in any other fashion. Simultaneously, however, some credence should be given to corporate sector pleadings regarding the necessity for maintaining an overall rate of return that is competitive with industry standards--in short, the two standards are not irrevocably opposed, but should be used where appropriate.

Exclusion of Debt in Calculating Rate of Return

Another major area of contention in developing rate of return analyses regards the questions of including debt in determining a return on investment. The weight of the evidence here also seems to lie on the side of exclusion--but with a major caveat which will be discussed below.

The opponents of including debt in the rate of return calculation point out that debt requires no return other than the interest payment which was negotiated at the time of the bank loan or the issuance of the bonds or debentures. Therefore, to attribute income from operations to borrowed money is, in the view of some, an entirely spurious method of calculating the proper rate of return--on a par with attributing income to non-existent stockholders.

In our judgment, this view is marginally correct. Debt is a useful and necessary financing tool for any large corporation which, if properly used, can provide an important impetus to earnings via financial leverage. However, simply assigning a "return" to debt upon which payment has already been made (since almost all rate of return calculations are made after payment of interest and taxes) is too simplistic and is probably incorrect.

As was stated initially, however, there is a caveat to this conclusion--and that is that debt does require some return greater than the simple amount of principal and interest due. This is because securities markets view maintenance of a "safety margin" of sufficient earnings to cover "fixed charges" as a matter of some importance--and if that margin is eroded or is non-existent a firm's access to the capital market will be constrained, via higher rates or otherwise. Consequently, a firm may argue persuasively that consideration of the interest and principal requirements <u>alone</u> and assigning no further rate of return requirement to debt obligations is fallacious--the firm must indeed earn some return on invested debt over and above interest and principal requirements if it is not to suffer real financial impacts. The amount of such required return is, of course, debatable. One of the commonest measures used by financial analysts in determining the financial soundness of a firm is the "times interest earned" measure. This simply records the ratio of a firm's pre-tax and pre-fixed charge income to total fixed charges and provides some relative measure of that firm's ability to meet its fixed obligations and avoid insolvency. Naturally, there is no "good" or "bad" times interest earned ratio--analysts can only look to corporate history or to the performance of other companies in the same industry group for a relative measure of a firm's performance in this area. It seems likely that such an analysis would be appropriate when considering the tax impact on firms operating in Alaska, at least to the extent of determining whether Alaskan operations and debt coverage ratios are, or are not, in line with general industry practice.

Federal Taxes: Paid or Not?

One of the areas where industry seems on the shakiest ground is in attributing fully taxed status to Alaska income. It takes little effort to examine the corporate financial statements of the firms operating in Alaska and find that they are paying tax rates well below the nominal federal rate of 48%. A more complex question involves determining what a proper tax deduction might be for determining the actual value of future cash flows from North Slope operations--this will vary from firm to firm and, naturally, makes analysis even more difficult.

At least a minimum approach to this problem would be applying the major tax reduction effects of the Investment Tax Credit (ITC) to the nominal rate on income earned in Alaska. A further step might be the limitation, in terms of analysis, of the corporate income tax rate to the highest rate reported by any one company operating in the state, above a certain size. Thus, the analysis of rate of return would turn up an estimate that could be stated as "a rate of return equal to or greater than" some percentage rate--since the rate of return would be pegged to the most highly taxed company in the jurisdiction, and all other companies would earn relatively higher rates due to their lower tax burden. We do not suggest that these approaches are entirely appropriate or that they are the only ones which could be utilized in attempting to reconcile rate of return analysis of nominal with effective federal tax rates. A more thorough analysis of this problem will be contained in our forthcoming rate of return analysis of Prudhoe Bay operations.

Non-Prudhoe Bay Exploration and Lease Costs

Another issue which has received some attention is the question of whether unsuccessful lease costs by non-Prudhoe Bay (or other unsuccessful) companies in Alaska should be viewed as a part of the total "investment" on which a rate of return for Prudhoe Bay should be calculated. Clearly, this type of analysis is inappropriate from a strict financial standpoint. There is no relationship between the monies spent by two competing companies, one of which is eventually successful and the other of which is not--attributing the failed investment to the successful company results in nothing more than a paper exercise, since the company that actually spent the money--and lost it--is no better off than before. Who is better off (at least in terms of this analysis--since a lower rate of return may mean a lower tax rate) is the company that was successful anyway.

There is, however, an economically based argument (as distinct from the purely financial and accounting position on this issue) favoring inclusion of unsuccessful lease costs in the overall investment base for rate of return determination. And that is simply that Alaska, from an economic standpoint, should be viewed as a unit. Thus, investments, losses, and gains should be viewed in terms of the political and geographic unit, and only secondarily in terms of the corporate entities which operate there. Thus, rate of return on the project would tend to translate into rate of return in Alaska--and Alaska's tax policy could then be set accordingly.

It is not obvious, however, that this line of reasoning results in an appropriate view of Alaskan economic activity. The result of such an approach remains that successful companies' rate of returns tend to be artifically lowered, while the rate of return of unsuccessful companies remains negative. The problem in the approach is that it attempts a "balancing" of interest in the interest of fairness--to compensate in the rate of return calculation for the risk factor associated with unsuccessful business ventures. This would be a workable approach if investment in Alaska were a closed universe. However, the universe of investment decisions is international--and the company that lost heavily in Alaska may gain heavily elsewhere. Thus, to the degree that Alaska provides additional compensation to the successful company (by attributing a lower rate of return and thus a lower tax rate), a misallocation of resources has taken place--since that company's overall return will be higher than it otherwise would have been in a competitive environment. In the final analysis, the key distinction between the two methods of calculating rate of return may lie in whether one wishes to view the rate of return of companies actually operating in the state, or to look at the rate of return on Alaskan operations in an abstract sense (Gregg K. Erickson, Director of Research, has additional and, in some instances, somewhat differing views regarding the treatment of unsuccessful lease costs. These will be provided you in the near future as an addendum to this discussion). In any event, the decision to exclude or include such unsuccessful lease costs has a reasonably substantial impact on the rate of return calculation result.

Considering Prudhoe Bay alone, inclusion of approximately $900 million in unsuccessful lease costs in the investment base (a rough estimate of the current level of losses on unsuccessful leases, whether or not abandoned) would lower the return on Prudhoe Bay operations, as calculated in Table III, from 36.6% to about 30%. For the field and pipeline together, the rate of return would decline from 16.3% to about 14.9%, if such costs were included.

Comparability of State Tax Rates

At the request of the House Finance Committee, we have conducted a joint effort with the Department of Revenue to determine the accuracy of industry statements regarding Alaska's relative tax position among the states. The specific area we were asked to analyze was that of severance taxation, while the Department of Revenue handled ad valorem and income taxes.

In our judgment, the application of the severance taxes of Louisiana, Texas and California to the income stream described by Sohio's Submission Two was accurate within acceptable limits--i.e., our calculations varied only about 3% from those submitted to the committee. Although we have not yet seen the formal analysis of the Department of Revenue (scheduled to be submitted in the form of testimony to the House Finance Committee on April 14, 1977) we have been informed verbally that:

1. The income tax estimates made by Sohio appear to be reasonably accurate.
2. There are major differences between the Department of Revenue's estimate of ad valorem tax liabilities among the various states and those contained in Submission Two.

According to the Department, their analysis shows Alaska to be 4th or 5th ranking in terms of ad valorem tax liability, instead of 1st or 2nd.

The absolute magnitude of the differences are not available from the Department at this writing.

APPENDIX A

Accuracy of Exxon Testimony Before Joint House-Senate Resource Committee

As part of their testimony to the Joint House-Senate Resource Committee, Exxon submitted an exhibit listing rate of return estimates prepared by five different sources. The range of these estimates was 11% to 18%, and they were submitted in support of the company's contention that rates of return on Alaska operations were not out of line with overall industry rates of return--which were cited as being 12.4% average return to net worth (an accounting measure of profitability that is not directly comparable to DCF return analysis). Following are our discussions of each estimate submitted by Exxon, in terms of the general issues covered in the body of the memorandum:

Estimate 1. L. F. Rothschild & Co., Securities Analyst, New York, N.Y., Investment report prepared December, 1975. Rate of return estimate: 18%.

The rate of return cited in the Rothschild study is not a DCF calculation but, instead, is simple accounting profit relative to invested capital in one year of operations--they calculated net profits to be approximately $600 million on TAPS operations and $1.2 billion annually on Prudhoe Bay crude oil production. Properly speaking, Rothschild did not present these figures as a "rate of return" but rather as "profit potential" at production levels of 1.5 million bb/d and Los Angeles sales prices of $11.00. There is no direct relationship between this sort of analysis and a DCF rate of return calculation.

Estimates 2 & 3. Both Exxon and the Standard Oil Company of Ohio indicated that their internal discussions had resulted in a rate of return of 15% and between 14% and 16% respectively for the project as a whole.

We are in no position to analyze the rates of return submitted by Exxon and Sohio, since no underlying assumptions were provided. Although we have requested such information in the past from the companies, no results have been forthcoming. The primary reason that has been cited is difficulty with Securities and Exchange Commission rules regarding corporate disclosures that would tend to forecast earnings. In any event, the returns were calculated on the basis of the entire project, debt as well as equity and, consequently, no matter how derived, are subject to the same limitations discussed in the main body of the memorandum. The similarity between the companies' average rate of return of 15% and the 16% average DCF rate of return calculated in our hypothetical earnings example in the attached memorandum is largely coincidental.

Estimate 4. Drexel Burnham & Company of New York, New York, performed an extensive analysis of North Slope earnings and profit potential in April, 1976. The rate of return cited by Exxon from this study was 17%.

The Exxon citation was correct, as far as it went. The 17% return figure was only one of several possible DCF returns cited by Drexel Burnham and covered the entire field and pipeline operation. Drexel Burnham also estimated, however, that return on the Prudhoe Bay field alone was 27% on a DCF return basis at a price of $13 per barrel in Los Angeles. Returns at lower prices of $11 per barrel went down to 23% return on the field and 14% for the project as a whole.

Estimate 5. The lowest rate of return cited by the Exxon testimony was that derived for the Federal Energy Administration by Mortada International (a consulting firm) in November, 1976.

The Mortada study, performed under contract to the Federal Energy Administration, had somewhat contradictory conclusions from the standpoint of the industry. On the one hand, the Mortada study indicated that a DCF rate of return of 11% to 13% was a proper measure of total project returns for North Slope operations--supporting the industry position that rates of return were in line with other oil industry returns. Simultaneously, however, Mortada suggested regulating the price of North Slope oil at Valdez in the range of $11.50 to $12.40 per barrel, indicating that such prices would approximately insure such a return and would also provide sufficient incentive for development of the more expensive Kuparik-Lisburne formations. The former conclusion was greeted more enthusiastically than was the latter.

Mortada arrived at its lower rate of return conclusions via a variety of assumptions not made by other analysts. First, of course, the return was calculated on the project as a whole, rather than on the component parts. Second, total costs dating back to 1964 for all North Slope exploration were included in the investment base for purposes of calculating rate of return. These costs were also adjusted upward to 1976 dollars (all returns were stated in "real" or constant dollars) and further multiplied by a "risk factor" to reflect the incidence of unsuccessful exploration efforts.

Of all the Mortada conclusions, the inclusion of the "risk multiplier" and its method of application is probably the most controversial. No other analysis provided to the committees, or in our files, includes such a method. Nonetheless, there is some underlying soundness in the concept that prior exploration costs should be somehow taken into account when considering the rate of return question. In our analysis, however, Mortada's approach to solving this problem was not particularly convincing.

Specifically, Mortada assumed that all prior North Slope expenditures represented one exploration "effort" and that the discovery of Prudhoe Bay was the result. By Mortada's reasoning, however, some accounting must be made for the "failed" exploratory efforts which by definition are more numerous than successful exploration efforts which result in Prudhoe Bay-type finds. To do this, they examined the success rate of exploratory ventures generally and determined that a reasonable estimate was one successful commercial discovery out of every seven tries. Consequently, while Prudhoe was a success, there were implied in that success six failures of approximately the same magnitude--consequently, an after-tax factor (since failures are deductible) to account for these hypothetical failures was applied to arrive at the "true" rate of return for Prudhoe Bay.

The problem with such reasoning is similar to that which was discussed in the section dealing with unsuccessful lease costs--attributing extra costs to the project, which in fact were not incurred in Alaska by the operating companies, is simply a paper exercise. Even worse, these costs (unlike the lease costs) were not even incurred--or deemed to have been incurred--in Alaska. The fact that the company may have unsuccessful exploration efforts around the world which will drag down its rate of return overall doesn't necessarily mean that the cost of such efforts should be rolled into Alaskan investments. Alaska, of course, can only tax those profits or activities occurring within its jurisdiction.

Since it cannot tax extra-jurisdictional profits (i.e., attribute an oil company's success somewhere else in the world back to Alaska for tax purposes), it seems to make little sense to carry unsuccessful investments back to Alaska for tax purposes either. This does not mean, of course, that some general provision for deductibility of Alaskan exploration and development efforts is inappropriate--the results of such deductions would simply reflect the real risk of looking for oil in Alaska and not hypothetical considerations of international exploration efforts.

Without the risk adjustment factor used by Mortada (which increased the investment base on Prudhoe Bay by about $900 million), the DCF rate of return calculated was 14.6%--still somewhat lower than calculated by other observers. One reason for the difference was their use of an unusually high Alaska-U.S. west coast transportation factor--$1.33 per barrel. This is compared with a more generally used figure of about $0.75 per barrel. Other possible differences emerge in the area of the TAPS tariff since their precise methodology in determining company profitability on the TAPS was not included in the report, nor was any discrete per/barrel cash flow by year of production provided.

4/15/77

Tax Hearings

Yesterday morning Dept Revenue testified that using Wainwright raw data, Revenue projected a 26.3% rate-of-return, while Wainwright used that data and got a 19.1%.

At that time Dept Revenue could not explain the difference. So SOHIO called the author in New York during lunch and presented a tape of the conversation to Finance committee that afternoon. It said: (Leibman)

(1) Difference was because Wainwright used a "real rate" which unlike the "nominal rate" (used by Rev.) does not account for inflation. Investors use the "real rate".

(2) Wainwright used a modified Governor tax package for its projections, because it wanted to use a "worst case". And it was more important to use 2 cases for Fed pricing and 2 cases for tariff as these have much greater effects than a tax change. Wainwright wanted to be "conservative in developing earnings estimates".

(3) Leibman said there are some "legitimate problems" in Alaska's tax structure; however, "on balance it is more than adequate given the State's fiscal outlook".

(4) Prudhoe Bay will have a "marginal" return on investment.

(5) Main problems with Gov's taxes:

a. ¢/barrel floor is based on "deemed market value" and the industry is caught between a fed/state conflict.

b. property tax should not be extended to LNG, etc.

c. extending state tax to OCS is unreasonable.

c. economic value assessment is bad -- it should remain on historic costs rather than replacement costs.

NOTE: Tom Williams talked with Leibman too -- and apparently, the Administration no longer supports its 26.5% figure -- though I am not sure.

AGC 531150 A

ADMIN

Dept Revenue
Tom Williams
4/77

CASH FLOW EFFECTS ON PRUDHOE BAY
DUE TO ADMINISTRATION'S TAX PROPOSALS
(Based on April 1, 1977 Report by
Wainright Securities Inc.)

($ millions)

Year	Production Tax	Property Tax	Franchise Tax	Total	Total after Federal Income Taxes
1977	-13	100	-25	62	32
1978	-43	0	-173	-216	-112
1979	-37	0	-184	-221	-115
1980	-140	0	-255	-395	-205
1981	-198	0	-302	-500	-260
1982	-135	0	-316	-451	-235
1983	-137	0	-330	-467	-243
1984	-143	0	-351	-494	-257
1985	-150	0	-379	-529	-275
1986	-159	0	-414	-573	-298
1987	-161	0	-425	-586	-305
1988	-155	0	-417	-572	-297
1989	-148	0	-411	-559	-291
1990	-137	0	-404	-541	-281
1991	-128	0	-396	-524	-272
1992	-103	0	-358	-461	-240
1993	-82	0	-326	-408	-212
1994	-66	0	-296	-362	-188
1995	-47	0	-269	-316	-164
1996	-37	0	-242	-279	-145
1997	-27	0	-221	-248	-129
1998	-15	0	-197	-212	-110
1999	-5	0	-170	-175	-91
2000	14	0	-145	-131	-68
2001	21	0	-129	-108	-56
2002	31	0	-111	-80	-42
2003	39	0	-98	-59	-31
2004	48	0	-83	-35	-18
2005	52	0	-74	-22	-11

AGO 531150 B.

PROJECTED CASH FLOWS FOR PRUDHOE BAY
UNDER PRESENT TAXES AND ADMINISTRATION'S PROPOSALS
(Based on April 1, 1977 Report by
Wainright Securities Inc.)

($ millions)

Year	Cash Flow under Present Taxes	Effects of Proposals	Cash Flow under Proposed Taxes
1959	-2	0	-2
1960	-1	0	-1
1961	-1	0	-1
1962	-7	0	-7
1963	-14	0	-14
1964	-19	0	-19
1965	-19	0	-19
1966	-4	0	-4
1967	-8	0	-8
1968	-9	0	-9
1969	-395	0	-395
1970	-69	0	-69
1971	-40	0	-40
1972	-19	0	-19
1973	-24	0	-24
1974	-145	0	-145
1975	-723	0	-723
1976	-1174	0	-1174
1977	-279	32	-247
1978	1359	-112	1247
1979	1528	-115	1413
1980	1907	-205	1702
1981	1933	-260	1673
1982	2119	-235	1884
1983	2512	-243	2269
1984	2757	-257	2500
1985	3420	-275	3145
1986	4131	-298	3833
1987	4094	-305	3789
1988	3928	-297	3631
1989	3811	-291	3520
1990	3654	-281	3373
1991	3516	-272	3244
1992	3185	-240	2945
1993	2867	-212	2655
1994	2585	-188	2397
1995	2343	-164	2179
1996	2084	-145	1939
1997	1946	-129	1817
1998	1754	-110	1644
1999	1508	-91	1417
2000	1300	-68	1232
2001	1169	-56	1113
2002	1024	-42	982
2003	915	-31	884
2004	791	-18	773
2005	707	-11	696

RATES OF RETURN (ON DCF BASIS)
FOR PRUDHOE BAY UNDER PRESENT TAXES
AND ADMINISTRATION'S PROPOSALS

Discount Rate (%)	Discounted Value of Cash Flow Under: Present Taxes	Proposed Taxes
10	3071	2762
12	1749	1560
14	997	880
16	564	490
18	313	265
20	166	136
22	81	61
24	31	18
26	3	-6
28	-12	-18
30	-20	-25

The DCF rate of return is that discount factor which yields a discounted value of zero for a given cash flow. For the Prudhoe Bay cash flow under the present tax structure, it is clear from the above table that the DCF rate of return is between 26% (which yields a discounted value of 3) and 28% (which gives a value of -12). By means of computer analysis, the actual rate of return for Prudhoe Bay under the present tax regime is 26.3%.

As also can be seen from the table, the DCF rate of return under the proposed taxes lies between 24% (discounted value of 18) and 26% (discounted value of -6). Again using a computer to narrow the range, the DCF rate of return under the proposals is found to be 25.4%.

THE IMPACT ON THE DCF RATE OF RETURN DUE TO THE TAX IS ONLY 0.9% (25.4% versus 26.3%). The effects on the DCF rate of return due to field productivity, development expense, time needed for development, and wellhead price are each much more important than this tax effect.

Wainwright error of 19.1% is wrong in Append B.

AGO 531152

ADMIN

TABLE 1. COOK INLET NATURAL GAS SEVERANCE TAX PROJECTIONS BY FISCAL YEAR AND TAX SCENARIO

Fiscal Year	Sales (Bcf/Y)	Average Price ($/Mcf)	PRODUCTION TAXES Existing ($/MM)	(Rate)	Proposed ($/MM)	(Rate)
1977	147.6	$.400	2.08	4%	2.08	4.0%
1978	166.4	$.400	2.33	4%	9.32	15.9%
1979	198.5	$.400	2.78	4%	11.78	17.0%
1980	257.5	$.419	3.78	4%	16.20	18.0%
1981	312.0	$.444	4.85	4%	20.81	19.1%
1982	333.3	$.464	5.41	4%	23.56	20.2%
1983	338.9	$.474	5.62	4%	25.40	21.4%
1984	344.9	$.485	5.85	4%	27.41	22.7%
1985	351.3	$.494	6.08	4%	29.58	24.1%

TABLE 2. PRUDHOE BAY NATURAL GAS SEVERANCE TAX PROJECTIONS BY FISCAL YEAR AND TAX SCENARIO

Fiscal Year	Sales (Bcf/Y)	Average Price ($/Mcf)	PRODUCTION TAXES Existing ($/MM)	(Rate)	Proposed ($/MM)	(Rate)
1977	2.78	$.30	.029	4%	.029	4.0%
1978	3.92	$.30	.039	4%	.219	21.3%
1979	5.13	$.30	.053	4%	.305	22.6%
1980	5.87	$.30	.063	4%	.369	23.9%
1981	28.03	$.424	.416	4%	1.870	18.0%
1982	42.96	$.495	.744	4%	3.037	16.3%
1983	777.42	$.731	19.879	4%	58.263	11.7%
1984	828.58	$.833	24.145	4%	65.823	10.9%
1985	868.70	$.883	26.847	4%	73.123	10.9%

TABLE 2A. PRUDHOE BAY NATURAL GAS
SEVERANCE TAX PROJECTIONS
BY FISCAL YEAR AND TAX SCENARIO

Fiscal Year	Sales ($/Mcf)	Average Price ($/Mcf)	PRODUCTION TAXES Existing ($MM)	(Eff.Rate)	Proposed ($MM)	(Eff.Rate)
1977	2.78	$.30	.029	4%	.029	4.0%
1978	3.92	$.64	.088	4%	.233	10.6%
1979	5.13	$.68	.122	4%	.305	10.0%
1980	5.87	$.72	.148	4%	.370	10.0%
1981	28.03	$.76	.746	4%	1.864	10.0%
1982	42.96	$.81	1.218	4%	3.045	10.0%
1983	777.42	$.85	23.128	4%	58.263	10.1%
1984	828.58	$.90	26.100	4%	65.823	10.1%
1985	868.70	$.96	29.188	4%	73.146	10.0%

Table 3

COOK INLET BASIN
Residential, Power Plant, and Commercial
Natural Gas Demand Projections
by end use and by year, 1977-1985
(in Bcf/Year)

Calendar Year	Chugach Electric Beluga Plant	City of Kenai	ALASKA PIPELINE COMPANY Electric Power	Military	Residential	General Service Small	Large	Total Demand
1977	11.28(a)	.40	11.16(b)	5.89(b)	6.51(b)	3.10(b)	4.34(b)	42.68
1978	12.86	.42	11.59	5.89	7.03	3.35	4.69	45.83
1979	13.37	.44	12.02	5.89	7.59	3.62	5.06	47.95
1980	14.85	.46	12.42	5.89	8.20	3.91	5.47	51.20
1981	16.45	.48	12.81	5.89	8.86	4.22	5.90	54.61
1982	18.26	.50	13.16	5.89	9.57	4.56	6.38	58.29
1983	19.57	.53	13.51	5.89	10.33	4.92	6.89	61.64
1984	19.77	.56	13.81	5.89	11.16	5.32	7.44	63.95
1985	19.77	.59	14.09	5.89	12.05	5.74	8.03	66.16

a. Power System Study, 1976 by Tippett and Gee, Consulting Engineers for Chugach Electric Association forecasts demand for the Beluga plant for the years 1977-1984.

b. Data supplied by Alaska Pipeline Company projects 1977 APC system demand at 31.0 Bcf: 36% used in Chugach and Anchorage Municipal electric power plants, 19% supplied to the military, 21% sold to residential consumers, 10% delivered to small commercial users, 14% sold to large (1200 Mcf per year) commercial users. Total system demand for APC 1977-1982 is expected to grow at 5% per year with nonpower usage increasing at a rate of 8% per annum.

Table 4

ESTIMATED TOTAL COOK INLET NATURAL GAS PRODUCTION AND RESIDENTIAL DEMAND BY UTILITY AND BY YEAR, 1977-1985
(in Bcf/Year and Percentage)

Calendar Year	Total Cook Inlet Sales	Volumes (%) Sold to or for Residential End Users: Alaska Pipeline Company	Chugach Electric Association	Anchorage MPL	City of Kenai
1977	157.0 (100%)	6.5 (4%)	6.8 (4%)	3.4 (2%)	.4 (.3%)
1978	172.5 (100%)	7.0 (4%)	7.7 (4%)	3.5 (2%)	.4 (.2%)
1979	228.0 (100%)	7.6 (3%)	8.0 (4%)	3.6 (2%)	.4 (.2%)
1980	284.8 (100%)	8.2 (3%)	8.9 (3%)	3.8 (2%)	.5 (.2%)
1981	322.7 (100%)	8.9 (3%)	9.9 (3%)	3.8 (1%)	.5 (.2%)
1982	335.0 (100%)	9.6 (3%)	11.0 (3%)	3.9 (1%)	.5 (.1%)
1983	342.0 (100%)	10.3 (3%)	11.7 (3%)	4.0 (1%)	.5 (.1%)
1984	348.0 (100%)	11.2 (3%)	11.9 (3%)	4.1 (1%)	.6 (.2%)
1985	355.0 (100%)	12.1 (3%)	11.9 (3%)	4.2 (1%)	.6 (.2%)

Assumptions:

1. 60% of volumes sold to Alaska Pipeline Company are in turn sold to residential consumers.

2. 60% of volumes sold to Chugach Electric Association are in turn used to supply power to residential consumers.

3. 30% of volumes sold to Anchorage Municiple Power and Light are in turn used to supply power to residential consumers.

4. 100% of volumes sold to City of Kenai are used to supply power to residential consumers.

Table 5

ESTIMATED DIRECT ECONOMIC IMPACT OF
NATURAL GAS SEVERANCE TAXES ON
AN AVERAGE ANCHORAGE RESIDENCE
($ per residence per year)

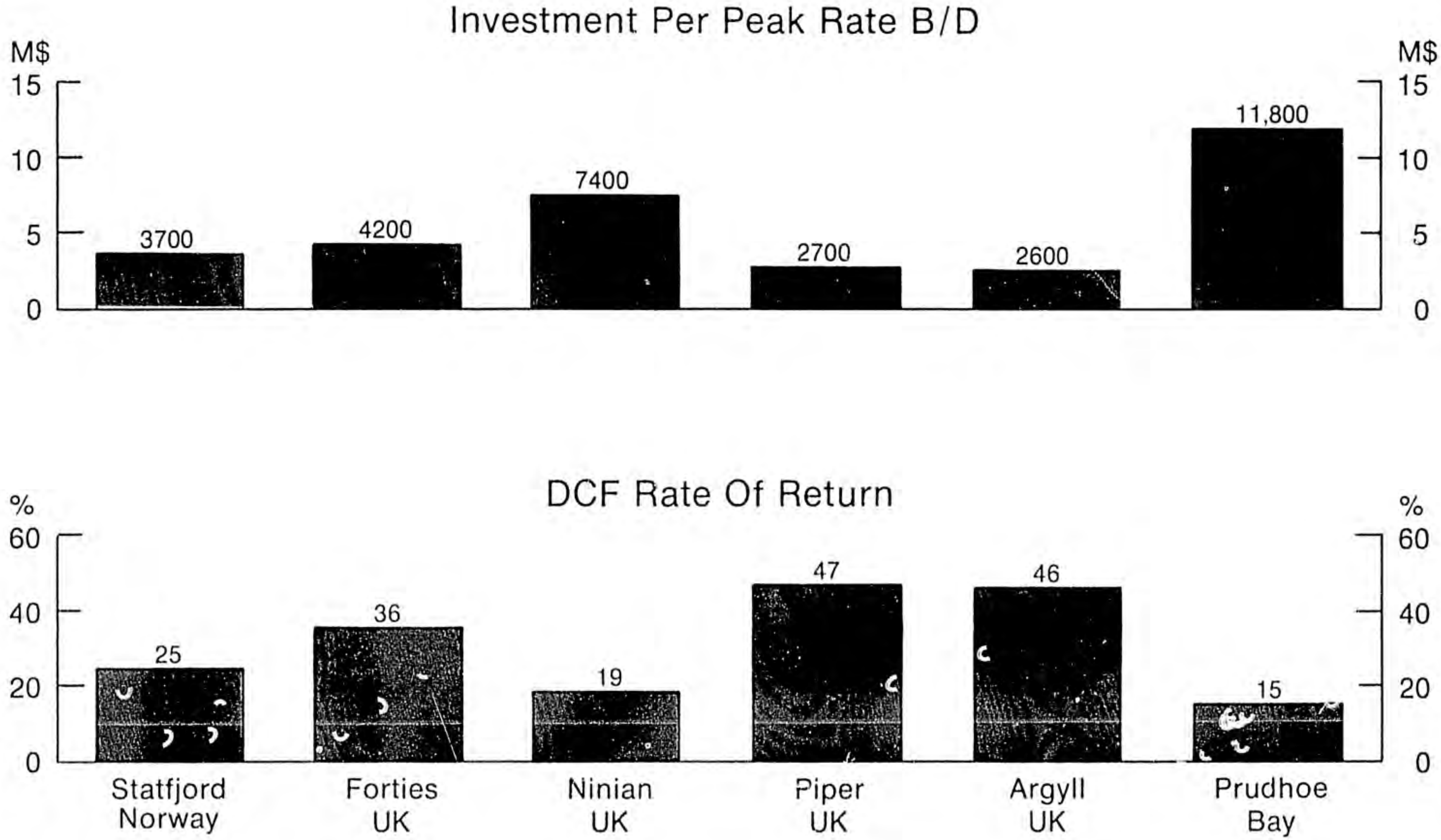
	Anchorage Natural Gas 1			Chugach Electric Association 2		
Calendar Year	Residential Customers	Existing Taxes	Proposed Taxes	Residential Customers	Existing Taxes	Proposed Taxes
1976	29,200	-	-	31,000	-	-
1977	31,500	$2.89	$ 7.49	33,200	$2.87	$ 7.44
1978	34,000	$3.04	$12.59	35,500	$3.21	$13.27
1979	36,800	$2.97	$13.34	38,000	$2.88	$12.92
1980	39,700	$3.13	$13.42	40,600	$3.32	$14.24
1981	42,900	$3.30	$14.26	43,500	$3,62	$15.65
1982	46,300	$3.41	$15.15	46,500	$3.89	$17.29
1983	50,000	$3.43	$15.90	49,800	$3.92	$18.14
1984	54,000	$3.52	$17.99	53,300	$3.79	$18.28

1. The average Anchorage Natural Gas residential billing for calendar year 1976 was $377.42 (226 Mcf @ $1.67 per MMBtu). Thus, existing and proposed severance taxes have a direct impact to the residential consumer of 1% and 2% respectively.

2. The average Chugach Electric Association residential customer paid $310.96 during calendar year 1976 (11,960 Kwh @ .026 per Kwh). Thus, existing and proposed severance taxes have a direct impact to the residential consumer of 1% and 2% respectively. At present Chugach Electric Association has a pending 15% rate increase which is being heard by the Alaska Public Utilities Commission. This rate increase dwarfs the effect of severance taxes.

Prudhoe Bay — North Sea Comparison

EXXON



AGO 531158

Alaska State Legislature
Senate

JUNEAU, ALASKA

4/15/77

TO: Sen Rader
FR: Connie
RE: Finance Tax Hearings:
Wed morning witness - Dr. Joseph Kemp
Professor of Economics
University of Aberdeen, Scotland

The following summarizes Dr. Kemp's major points:

Morality Arguments - Just as in AK, Britain issued "licenses" for oil exploration & development at 12½% royalty. Britain still has this royalty, but has increased its taxes to obtain profitibility of finds.

Kemp argues that there is no morality argument. A government taxes on taxable capacity; and no government surrenders its sovereign right to tax.

Note: All gov't oil revenues going into Genrl Fund to pay back deficits & to use as collateral for getting loans. None is being saved.

Taxation in Britain - Prior to oil discoveries, Britain simply used a 12½% royalty and 52% corporate income tax.
In 1974 govt negotiated with companies and in Feb 1975 offered a new tax package. That package kept the royalty and income tax the same; however it instituted a new "petroleum revenue tax" which was credited against income tax, of 45 %.
The corporate income tax remained ineffective with its foreign tax credits, etc, so this new PRT tax was designed.
The effective rate of the PRT is somewhat less than 45% because X amount of production is free of tax to help independent or marginal operations. PRT applied on a field by field basis and did not allow tax allowanaces from outside (foregin credits).

NOTE: I see 2 things this tax package allows which AK currently doesn't to aid the industry:

(1) Kemp said that UK remits royalties on marginal fields (tho AK statutes allow it, I don't think its ever been used to establish a dependable policy)

(2) Kemp mentioned (and Showalter confirmed) that UK allows companies to recover their capital before any taxes imposed. So companies allowed to expense outlays rather than capitalize them and amortize them thru time. Front-end recovery of $.

PARTICIPATION BY GOVT

Britain recently completed 5th round of "licensing" (leasing) in North Sea. This round the govt required that the British national Oil Company participate in each license by holding 51% of the share. Kemp states that companies dislike participation more than dislike taxation. (So as long as Alaska only taxes, we aren't hitting them that hard.) I questioned Kemp afterwards as to how the profits are shared & how that effects rate of return, and he stated that "Participation" does not mean profit sharing -- just simply the government having a say in how oil is produced. Companies dislike this because they are forced to disclose all info to govt and govenrment controls timing of development and production decisions.

As a policy matter, apparently Britain is allowing companies to develop as quickly as possible; whereas Norway is holding back development.

GOVERNMENT TAKE

Britain - with 12½% royalty and 52 % corporate income and 45% PRT (credited against income tax), Kemp says that the Government take is between 60 - 70 % of total profits.

Norway - With a 50.8% corporate income tax and a 25% special income tax (with no generous allowances like the UK PRT has), the Government take is between 65 - 75% of profits.

US - Wainwright chart on page 36 shows a 54% govt take (state, fed, local) and 46 % oil company take. for Prudhoe Bay. Tanzer shows 37% company take under State's present tax structure (63% govt take)

RATE OF RETURN

Britain North Sea - If price of oil keeps up with inflation rate of return for the several fields will range from 20% for the least profitable to 40% for the most. If oil price doesn't keep up with inflation, range will be 13 - 40 %.

What's Needed - Chairman of Dutch Shell said needed 15% ROR in North Sea due to high risks. Chairman of Gulf said needed as much as 25%, for North Sea. First City Bank shows average US rate = 11-12%.

NOTE: Britain's tax package allows a 40% rate of return on the most profitable fields. Even tho it can be argued that on-shore Alaska is less risky than North Sea; no one can say Prudhoe shouldn't be viewed here as a "most profitable field".

~~Wainwright Report~~

NET INCOME

1. Concur with Zeifman's suggestions for additions to prefacatory language?

2. If Federal OCS Lands Act Amendments pass with a state revenue-sharing provision, would you still urge passage of a franchise tax?

3.

Wainwright estimates DCF rates of return for Prudhoe (assuming effective 9.4 state tax plus using Governor's severence package) of :

10.6 for line (assuming ICC bases on equity)
19.1 for field
15.7 if combine field and line

Wainwright then says (p35)

"Relative to DCF rate of return objectives of 20 -25% set by many companies for exploration and production ventures, and actual rates of return for some of the larger North Sea fields far in excess of that, a real rate of return of just under 16% for the largest oil field ever gound in North America provides an interesting perspective on the question of economic rents."

Drexel Burnam estimates rate of returns as:

10% for TAPS
23-27% for field (if 11.00 of 13.00 market price)
14 - 17 % combined field and line

Tanzer estimates rate of return on field alone (using Drexel Burnham figures, but showing an effective state income tax rate of 2.5 and including tax credits accumulated to date) as 29% for companies.

Note: In terms of rate of return, the big question is whether or not to include the pipeline. Someone should ask Kemp whether the figures he cited for rates of return in the North Sea Included pipeline transportation costs & profits to shore.

VARIOUS RATE of RETURN ESTIMATES
PRUDHOE BAY FIELD

L. F. Rothschild & Co., Securities Analyst New York, NY Report Prepared December, 1975	18%
Standard Oil of Ohio Testimony Before State of Alaska Joint Senate/House Resources Committee March, 1976	14-16%
Exxon Company, USA Testimony Before State of Alaska Joint Senate/ House Resources Committee March, 1976	15%
Drexel Burnham & Co., Securities Analyst, New York, NY Report Prepared April, 1976	17%
Mortada International, Consultant Firm, Dallas, TX. Study Prepared for the Federal Energy Administration November, 1976	11-13%

Exxon

EXHIBIT 1

NORTH SLOPE ECONOMICS
DATA SOURCES & MAJOR DATA ITEMS

A. Data Sources:

1. Field Economics

a. Future production rates, investments, operating costs and oil well head prices: State of Alaska's reserves tax study, February 9,1976.

b. Gas prices and cost of gas gathering and conditioning expenses: From February 1977 advance submission to Canadian NEB by Mr. Radford Shantz, Foster Associates and producer testimony.

c. Historical investments: Sohio/BP Trans Alaska Pipeline Finance, Inc. Prospectus, December 4, 1974; The Standard Oil Company (Ohio) Prospectus, December 2, 1976; City of Valdez, Marine Revenue Bonds Preliminary Official Statement, January 27, 1977.

2. TAPS Economics

a. Total cost: Alyeska announcements.

b. TAPS will be regulated. Tariffs allowed under ICC rules result in DCF returns from 12% to 14%.

3. Tanker Economics: Consultant reports to FEA, November 1976 (Mortada Study). 10% Return on Investment.

B. Major Data Items:

1. Tanker Investment: $1,760MM

2. TAPS Investment - for 1.2 MMB/D: $7,700MM
- for 1.6 MMB/D: $8,375MM

3. Field Investment - initial: $3,610MM
- ultimate: $9,280MM

4. Oil Production - Reserves: 8.2 Billion Bbl
- Peak Rate: 1.6 MMB/D

5. Gas Sales - First Year: 1983
- Rate: 2.0 Bcf/D

6. Wellhead Prices - Oil: 1978 $6.67)
1980 $7.28) average: $7.77/Bbl
1985 $8.03)

Gas: All Years $0.852/Mcf
($0.071/MMBtu) (Separator Outlet)

EXHIBIT 2

AGO 531164

NORTH SLOPE ECONOMICS

INTEGRATED RATE OF RETURN

	Investment MM$	DCF Rate of Return
Field & Bonus	10,180	17.6
TAPS	8,375	12.0
Tankers	1,760	10.0
Total	20,315	14.5*

* Based on the investment weighting technique using total capital employed.

AGO 531165

NORTH SLOPE ECONOMICS

DIVISION OF PRUDHOE BAY FIELD LEVEL INCOME

LIFE OF FIELD BASED ON CONSTANT 1976 DOLLARS

		1976 Outlook MM$	%
Wellhead Value (8/8):	Oil	63,343	
	Gas	14,927	
	Total	78,270	
Field Investments		-9,280	
Field Operating Costs		-6,640	
Field Level Income		62,350	
State:	Royalty	9,784	
	Bonus	900	
	Production Tax	4,082	
	Ad Valorem Tax	1,857	
	Income Tax	2,626	
	Total	19,249	31
Federal Government		20,073	32
Oil Companies		23,028	37
		62,350	100

EXHIBIT 4

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907·465·3800

M E M O R A N D U M April 12, 1977

SUBJECT: Rate of Return Analysis on North Slope Operations and Comparison of Alaskan Oil Tax Rates With Other States (W.O. #4017)

TO: The Honorable John Rader

FROM: Richard G. Haggart
Research Analyst

This memorandum is in response to your request that we analyze recent oil industry testimony before the Joint House-Senate Resource Committee hearings on oil taxation. Specifically, you requested that we examine:

1. Competing statements and claims regarding rates of return that will be, or may be, earned on North Slope operations, in terms of overall accuracy and the appropriateness of underlying assumptions.

2. Whether the relative tax collection rates developed by Exxon and Standard Oil of Ohio for Alaska and other oil producing states accurately reflect current and proposed law.

Because of the complex nature of the issues involved and your need for a timely response because of the Finance Committee hearings on oil taxation beginning April 12, 1977, we have not been able to respond to your request in as full and complete a manner as we would prefer. Consequently, this memorandum includes only the following items:

1. A general discussion of discounted cash flow rate of return analysis and the major issues affecting such analysis, in terms of North Slope operations, and which cause significant variations among different forecasts of rates of return.

2. An appendix in which the specific rates of return cited by Exxon in their testimony of March 24, 1977, are examined for technical and methodological accuracy.

3. A brief analysis, performed in conjunction with the Department of Revenue, regarding the accuracy of Exxon's and Standard Oil of Ohio's statements regarding relative tax rates among oil producing states.

A fourth part of the memorandum is still in preparation and will be submitted to you by the end of April. In part four, we plan to develop a cash flow earnings model of Prudhoe Bay and the pipeline and examine the resulting rate of return from a variety of viewpoints. It is hoped that this analysis will help relieve some of the current confusion surrounding the issue of North Slope profitability and rate of return analysis.

RGH:jm
Attachment

or not abandoned) would lower the return on Prudhoe Bay operations, as calculated in Table III, from 36.6% to about 30%. For the field and pipeline together, the rate of return would decline from 16.3% to about 14.9%, if such costs were included.

Comparability of State Tax Rates

At the request of the House Finance Committee, we have conducted a joint effort with the Department of Revenue to determine the accuracy of industry statements regarding Alaska's relative tax position among the states. The specific area we were asked to analyze was that of severance taxation, while the Department of Revenue handled ad valorem and income taxes.

In our judgment, the application of the severance taxes of Louisiana, Texas and California to the income stream described by Sohio's Submission Two was accurate within acceptable limits--i.e., our calculations varied only about 3% from those submitted to the committee. Although we have not yet seen the formal analysis of the Department of Revenue (scheduled to be submitted in the form of testimony to the House Finance Committee on April 14, 1977) we have been informed verbally that:

1. The income tax estimates made by Sohio appear to be reasonably accurate.
2. There are major differences between the Department of Revenue's estimate of ad valorem tax liabilities among the various states and those contained in Submission Two.

According to the Department, their analysis shows Alaska to be 4th or 5th ranking in terms of ad valorem tax liability, instead of 1st or 2nd.

The absolute magnitude of the differences are not available from the Department at this writing.

Alaska State Legislature

Senate

JUNEAU, ALASKA

Reference the "Prudhoe Profits" files for rate-of-return estimates by:

Wainwright Securities
Drexel-Burnham
Mortada (for FEA)

AGO 531171

S 10