SCOMM

#13:9

March 26, 1976

The Honorable John L. Rader
Chairman, Gas Pipeline
Impact Committee
Alaska State Legislature
Juneau, Alaska 99811

Dear Senator Rader:

Support for a trans-Alaska gas pipeline has been a top priority of this Administration for some time, and the recent activities of the Legislature's Gas Pipeline Impact Committee and the Legislature as a whole indicate that the priority of this issue is a shared judgment. Stated conclusions and findings recently issued from your Joint Committee and apparently well accepted in the Legislature indicate that additional activities and governmental actions in support of an Alaska gas line should be considered at the earliest possible time. To this end, I would like to indicate to you some existing and contemplated actions of the Administration in this regard.

First, I should point out to you that the Administration has recently made a decision to participate in the hearings of the National Energy Board in Canada as it takes up the issue of gas pipeline routing. Although a schedule for this has not yet been set, the intention of the State to participate is firm, and our participation will be supported under existing funding provided to the Department of Law. In addition, Lieutenant Governor Thomas will be making a major appearance in Canada in May in support of an Alaskan line.

Second, within the very near future, a supplemental appropriation request will be forwarded for the purpose of supporting professional legislative and administrative assistance for the State in Washington, D. C., on this issue. This request in the amount of $50,000 will be used to further represent the State's position on the gas line issue at the Federal level and insure that lines of communication between the State and Washington are as good as possible on this issue.

Third, the stated conclusions and findings recently issued from your joint committee and well accepted in the Legislature indicate that, as an exception to the stated objectives of the royalty oil and gas statute to foster in-State use, the sale of royalty gas now for the purpose of assisting the promotion of a trans-Alaska pipeline may be appropriate.

Consideration of a sale for this purpose has been an ongoing aspect of the Administration's work respecting both the gas line and royalty gas issues. To date, in spite of substantial efforts on our part, it is my judgment that no offer to purchase gas has been put forward that presents benefits of a sale to promote the gas line which outweigh the disadvantages of losing options relating to in-State use which occurs if State royalty gas is sold for export from the State.

Nonetheless, our efforts to investigate this possibility have continued, and pursuant to the recent actions of the Joint Committee, a substantial renewed effort is now being made to stimulate new and better offers from all of those previously interested in State gas, as well as some new potential buyers. As you know, the Administration has supported the supplemental appropriation for this purpose submitted at the request of the Gas Line Impact Committee.

To be acceptable, any new offer will have to be predicated on important new support for an Alaskan route, be valid only if this route is selected, and offer to purchase only Alaska surplus gas so as to leave an unquestionably adequate supply for Alaska's future use. Some future needs within Alaska are known. Others are not, nor will they be known in the short-term future. Any sale, to be satisfactory, must protect the State's future both for the known and the hoped for but presently unknown, uses of its royalty gas.

I hope and intend that this process will be successful in determining if a gas sale can be made which makes a difference in the gas line decision, or if such a sale is not in the Alaska interest at this time. Substantial difficulties exist regarding the limited time available for the processes of the royalty sale statute to be carried out. Such time constraints are undesirable, but in an effort to explore all avenues on this matter, my efforts will continue and be emphasized during the short time period available.

Since no acceptable offer has been made yet, in my view, the entire royalty process must take place, including the submittal of new offers, negotiations, administration decision, Royalty Board and Legislative approval. For this process to take place within the confines of the present Session will be difficult, yet the effort is important, and it is already actively under way. The length of the Session is the limiting factor which must be recognized, and I solicit your cooperation in informing me at appropriate times regarding your expectation for adjournment. Although I will make every effort to expedite Administration consideration of this matter, I think it extremely unwise that we subvert the overall State interests to a pressured decision on this matter if it is avoidable, and I know you agree.

I hope this brief outline, in addition to the material already supplied by members of the Administration to your recent hearings, details the continued intent of this Administration to aggressively pursue its policy favoring the trans-Alaska gas line. Our efforts will continue in this spirit, and we look forward to cooperation with the Legislature.

Very truly yours,

Jay S. Hammond
Governor

cc: The Hon. Chancy Croft, President of the Senate
The Hon. Mike Bradner, Speaker of the House

bcc: The Hon. Lowell Thomas, Lieutenant Governor
Commissioner Martin

GRM:lb

-TO: Rep. Steve Cowper, Chairman
- Subcommittee on Revenue Sources

FROM: Jim Rhode
AA to Rep. Malone, Chairman
House Finance Committee

SUBJECT: The Rothschild Memorandum

At your request, we have reviewed "The Trans-Alaska Pipeline and Prudhoe Bay Crude Oil Production . . . Profit Potential", prepared by Rothschild and Co., New York, dated 2 December 1975 ("Corrected Version").

Rothschild concludes that the pipeline and the Prudhoe Bay fields will have a ". . . . return of 18% on the estimated $10 billion initial investment . . ." (page 3) as follows:

$$\frac{\text{\$.6 billion annual net profits of pipeline} \quad \text{\$1.2 billion annual net profits of field production}}{\text{\$10 billion initial investment}} = \frac{\$\,1.8}{\$10.0} = 18\%\ \text{return}$$

This "simple accounting profit" is not the proper basis of tax policy for the oil industry, lumps pipeline and oil field numbers that should be kept separate, is computed in an incorrect manner, and rests on a bad estimate.

Unlike the calculations of Tanzer Economic Associates and of the oil companies themselves, these "returns" are not based on "discounted cash flow". That is, they do not allow for the fact that profits are impacted not only by the relative amounts of revenue and cost that are involved, but also, by how long this money can or cannot be put to use.

If simple accounting profits were a sound measure of profitability, the returns for the pipeline would not be averaged with those for the oil fields. Pipelines, as regulated public utilities, are limited by law to seven percent on total investment. Lumping the returns for the pipeline with those for the field is to claim that investors and companies should have their smaller returns on the pipeline made up by far larger returns on the field. (Actually, the best measure here would be returns to equity which, under ICC practice, are 15% of total investment. In this instance, the net annual income of $.6 billion is a 46% return on the equity of $1.3 billion - including a return on the interest charges for borrowed capital.)

Once the field is separated, the simple accounting profits should be annual net profits over total investment (exploration, leases, and development, but not operating costs). Instead, we are given annual net profits in a peak year (not the average) and "initial" (not total) investment. Presumably, $8.65 billion of the $10 billion is the final cost of the pipeline (including funded interest) with 1.5 million bbls per day capacity, for this is the case used to compute the net profits on the field (page 6). This leaves $1.35 billion for the "initial" field investment alone, a figure that is unaccounted for by any text or table and several billions under the figure used by Tanzer. Indeed, were this our measure of the profitability of the field, $1.2 billion on $1.35 investment would bring the stunning return of 89%.

There are many other errors and questionable numbers in the memorandum. No mention is made of the reserves tax and its credit against severence. They do not realize that our severence tax is graduated nor do they cite the provisions or collection history of the Interstate Tax Compact on income taxation. They do not accord separate tax treatment for intangible (drilling) and tangible expenses. The 20 mill property tax on pipeline and field equipment is miscalculated. Their estimate of the major reserve positions in Prudhoe Bay are mistaken. No data in the paper is documented. In addition, no attempt was made to obtain the production buildup or pipeline tariff estimates of the State Treasury Division and the Oil and Gas Division.

Remarkably, after reviewing three of their estimates of net profit per barrel, we find they are not significantly different from comparable Tanzer estimates.

Given the faults of this memorandum, we are not suprised at reports that, until recently, oil industry officials criticized Rothschild for concluding that an ". . .18% . . . (is) . . . not a terribly attractive return . . .", fearing this would affect their latest efforts to obtain financing.

H.C. WAINWRIGHT & CO.
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# SPECIAL REPORT

## Alaskan Tax Proposals

January 22, 1976 NORTH SLOPE OIL AND GAS

State Senator John Huber, Chairman of the Special Committee on Revenue and Taxation, has announced his intention to introduce three bills to further tax the oil and gas industry in Alaska. These measures call for: (1) an increase in the effective severance tax to 12½%* (estimated statewide weighted average) from the current approximate 8% rate; (2) the introduction of a "properties net proceeds tax," which would revamp the state corporate income tax for oil companies and assure that, at a minimum, income taxes would amount to about 9.4% of pretax income; and (3) the establishment of an "excess value surtax" mechanism, whereby the state's share of the "net proceeds" (after all costs) from the sale of Alaskan oil – at prices above a state-determined crude oil value – would escalate significantly.

In essence, neither of the first two proposals are particularly new or surprising. Our October 16, 1975 *Industry Review* discussed in some detail the State of Alaska as a source of investment uncertainty in evaluating the North Slope project and specifically pointed to the likelihood of a resurrected proposal to revise the severance tax upward. Similarly, our previous calculations have also assumed accrual of a full 9.4% state corporate income tax rate. However, a restructuring of the tax in the form of a net proceeds levy, with provisions for a larger take above a certain crude price level, is without question a new and disturbing twist in the Alaskan petro-political situation.

At the start, it should be stated that this proposal, which is still in committee, is very preliminary in nature. Notwithstanding this important caveat, it is useful to review the

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**The revised severance tax schedule is as follows:*

| *Well Output* | *Rate* |
|---|---|
| *0 – 300 b/d* | *5.0% (unchanged)* |
| *300 – 1,000 b/d* | *6.0 (unchanged)* |
| *1,000 – 2,000 b/d* | *11.0* |
| *2,000 b/d +* | *14.5* |

*Thus, for a 10,000 b/d Prudhoe Bay well, the weighted average severance would amount to 13.3%. Also, it appears that the state will retain its alternative minimum cents-per-barrel computation.*

mechanism contemplated here to clarify some of the initial confusion about how such a tax would work and to assess the potential impact on production earnings for the three principal Prudhoe Bay leaseholders.

There has been some confusion about the proposal as to whether this new tax would be based on landed West Coast values, a wellhead price, or some intermediate standard; however, our contacts with this committee clearly indicate that the starting point for computation is currently intended to be a West Coast market value. In essence, the proposed "excess value surtax" would determine a "long-term price" for Alaskan oil and would levy a tax higher than the 9.4% current rate on the difference between the market price of the oil and this "long-term price" less full allowances for existing burdens on the gross proceeds of production (i.e., royalty and severance taxes). In discribing his scheme, Senator Huber has emphasized that he intends the "long-term price" to be high enough to ensure that capital continues to be attracted to the Alaskan petroleum industry. Toward this end, his bill incorporates certain safeguards for setting and revising this state-determined value (discussed below). He has further stated that the tax is designed only to capture for Alaska a portion of any windfall resulting from a rise in prices above the threshold price required for new investment.*

The following calculations are offered only as two specific examples. However, they are based on a methodology that has been confirmed by a staff aide of the Special Committee on Revenue and Taxation and on indications of what might constitute reasonable ranges for both the state-determined "value" of oil (above which an "excess value surtax" would be imposed) and the rate of incremental taxation.

(See tables on following pages)

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*These apparently comforting remarks are far less reassuring when coupled with Senator Huber's stated belief that there will clearly be a windfall for Prudhoe Bay producers, in contrast to our October 1975 calculations, which showed – based on a $12 West Coast price and a 1.5 million b/d production rate -- a total current return (including pipeline earnings of $586 million) that would approximate 17%. However, it should be noted that this calculation does not take into account the time weighting of several billion dollars of expenditures that will have been nonproductive for many years.*

## Case A

| | | | |
|---|---|---|---|
| Pipeline throughput 1.5 million b/d | | $12.00 | |
| West coast price | | | |
| "Long term price" | $7.00 | "Excess value" | $5.00 |
| Less: Pipeline tariff & tankers | 4.51 | | – |
| Wellhead | $2 49 | | – |
| Less: Royalty @ 12½% | 0.31 | | 0.63 |
| Severance @ 13.3% (12.22) | 0.33 (.275) | | 0.66 (0.55) |
| Lifting, depreciation & amortization | 0.44 | | – |
| Pretax profit | (.35) $1.41 (1.46) | 3.82 | $3.71 |
| Less: State income tax (a) | 0.13 (9.36% rate) (.13) | 1.91 | 1.86 (9.4% + 40.6%) |
| Federal income tax @ 48% | 0.61 (.62) | .92 | 0.89 |
| Net income per barrel | $0.67 (.71) | .99 | $0.96 |
| Combined profit per barrel | | $ 1.63 (1.70) | |
| Previous estimate (HCW Industry Review 10/16/75) | | 2.54 | |
| Downward adjustment | | $ 0.91 | |

*(a) Assumes deductibility of state income tax for Federal tax purposes.*

**Production earnings effect:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Atlantic Richfield | | | | | | | | |
| 315,000 b/d | x | 365 | x | $2.54/bbl | = | $292 million | or | $ 5.06/sh. |
| | | | x | 1.63/bbl (1.70) | = | 187 million | or | 3.24/sh. |
| | | | | | | $105 million (201) | | $ 1.82/sh. |
| Standard Oil of Ohio | | | | | | | | |
| 714,000 b/d | x | 365 | x | $2.54/bbl | = | $662 million | or | $10.17/sh. |
| | | | x | 1.63/bbl (170) | = | 425 million | or | 6.53/sh. |
| | | | | | | $237 million (443) | | $ 3.64/sh. |
| Exxon | | | | | | | | |
| 315,000 b/d | x | 365 | x | $2.54/bbl | = | $292 million | or | $ 1.31/sh. |
| | | | x | 1.63/bbl | = | 187 million | or | 0.84/sh. |
| | | | | | | $105 million | | $ 0.47/sh. |

| State of Alaska Revenues (In millions): | Previous (10/16/75) | Revised | Net Increase |
|---|---|---|---|
| Royalty | $ 514.7 | $ 514.7 | – |
| Severance taxes | 388.7 | 542.0 | $153.3 |
| State income taxes | 279.2 | 1,089.5 | 810.3 |
| Total revenues | $1,182.6 | $2,146.2 | $963.6 |

*Case A: State-determined "long-term price" $7.00 per barrel; 50% combined state income tax.*
*Case B: State-determined "long-term price" $9.00 per barrel; 25% combined state income tax.*

**Case B**

| | | | | |
|---|---|---|---|---|
| | **Pipeline throughput 1.5 million b/d** | | **$12.00** | |
| | West coast price | | | |
| | "Long term price" | $9.00 | "Excess value" | $3.00 |
| Less: | Pipeline tariff & tankers | 4.51 | | – |
| | Wellhead | $4.49 | | – |
| Less: | Royalty @ 12½% | 0.56 | | 0.38 |
| | Severance @ 13.3% (12.62) | 0.60 (.50) | | 0.40 (.33) |
| | Lifting, depreciation & amortization | 0.44 | | – |
| | Pretax profit | $2.89 (2.99) | | $2.22 (2.29 |
| Less: | State income tax (a) | 0.27 (9.36% rate) .28 | | 0.56 (9.4% + 15.6%) (.5 |
| | Federal income tax @ 48% | 1.26 1.30 | | 0.80 (.82) |
| | Net income per barrel | $1.36 1.41 | | $0.86 (.90) |
| | Combined profit per barrel | | $ 2.22 2.31 | |
| | Previous estimate (HCW Industry Review 10/16/75) | | 2.54 | |
| | Downward adjustment | | $ 0.32 (.23) | |

*(a) Assumes deductibility of state income tax for Federal tax purposes.*

**Production earnings effect:**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Atlantic Richfield | | | | | | | | | |
| 315,000 b/d | x | 365 | x | $2.54/bbl | = | $292 million | or | $ 5.06/sh. |
| | | | x | 2.22/bbl | = | 255 million | or | 4.42/sh. |
| | | | | | | $ 37 million | or | $ 0.64/sh. |
| Standard Oil of Ohio | | | | | | | | |
| 714,000 b/d | x | 365 | x | $2.54/bbl | = | $662 million | or | $10.17/sh. |
| | | | x | 2.22/bbl | = | 579 million | or | 8.89/sh. |
| | | | | | | $ 83 million | or | $ 1.28/sh. |
| Exxon | | | | | | | | |
| 315,000 b/d | x | 365 | x | $2.54/bbl | = | $292 million | or | $ 1.31/sh. |
| | | | x | 2.22/bbl | = | 255 million | or | 1.14/sh. |
| | | | | | | $ 37 million | or | $ 0.17/sh. |

| State of Alaska Revenues (In millions): | Previous (10/16/75) | Revised | Net Increase |
|---|---|---|---|
| Royalty | $ 514.7 | $ 514.7 | – |
| Severance taxes | 388.7 | 547.5 | $158.8 |
| State income taxes | 279.2 | 454.4 | 175.2 |
| Total revenues | $1,182.6 | $1,516.6 | $334.0 |

*Case A: State determined "long-term price" $7.00 per barrel; 50% combined state income tax.*
*Case B: State determined "long-term price" $9.00 per barrel; 25% combined state income tax.*

Based on our understanding of the mechanics of the various tax proposals, the $2.54 per barrel estimate for Prudhoe Bay field (Sadlerochit, Sag River, and Shublik formations) unit profitability at a pipeline throughput rate of 1.5 million b/d and a $12 per barrel West Coast landed price, as contained in our October report, would be reduced to a range of $1.63-$2.22 per barrel, as illustrated by Case A ("worst case") and Case B ("best case"), respectively. Conversely, the State of Alaska's revenue take would be significantly boosted – by $334 to $964 million – by the combination of an increased severance tax and the "excess value surtax."

It should be emphasized, however, that several items under consideration for inclusion in Senator Huber's proposed windfall profits tax could moderate its eventual impact on the Alaskan oil industry. These possible provisions include:

(1) An automatic inflation adjustment (tied to the Wholesale Price Index) to be applied annually to the state determined "long term price";

(2) The formation of a State body or board to periodically review (and presumably propose modifications to) the "long term price"; and

(3) A $1 per barrel supplemental allowance to the "long term price" for a given field in which the sum of all pretax expenses (including state royalty and severance tax) would fall within $1 of the "long term price" set by the State of Alaska.*

At this point, a few comments about legislative procedure and scheduling are appropriate. It is now contemplated that the three bills on oil taxation will be formally introduced within the next week or so. To become law, they must undergo consideration by four other committees (the Finance and Resource committees of both Houses), have all differences resolved in joint committee sessions, be voted out in final form by both Houses, and be signed by Governor Hammond. Clearly, a great deal of coordination will be necessary if all of this is to be successfully accomplished during the current 90-day session, which is expected to run until mid-April. Moreover, the possible reintroduction of one other piece of oil-related legislation – revival of an earlier concept for additional taxation of pipeline earnings – may further complicate the 1976 legislative calendar.

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**This provision appears designed to aid the economics of high cost fields. Given the relatively low costs of the Prudhoe Bay field, however, the $1 per barrel profit safeguard will not be generally applicable. For example, under Case A, the sum of all expenses – $5.59 per barrel – would be 42¢ below the level required to qualify for the $1 per barrel increment.*

A more definitive assessment of Prudhoe Bay field economics, as well as the future environment for oil company exploration and development activity in Alaska, will be possible as further details on these proposed tax changed emerge following introduction of the bills into the Legislature – when it will become clear what inevitable compromises must accompany broad legislative support of parts or all of the package.

H. C. WAINWRIGHT & CO.
Thomas A. Petrie
Paul R. Leibman

**H.C. WAINWRIGHT & CO.**
*Established 1868*

# INDUSTRY REVIEW

This Report Replaces Our Report of October 7, 1975

October 16, 1975

## NORTH SLOPE OIL AND GAS
Atlantic Richfield (ARC)
Standard Oil (Ohio) (SOH)

### *Commentary*

During the past five months, there have been further developments affecting a number of key elements of the North Slope development project that, of necessity, were addressed in a provisional manner in our May, 1975 North Slope Oil and Gas *Industry Review* and the accompanying *Basic Reports* on Atlantic Richfield and Standard Oil of Ohio. In particular (1) the 1975 construction season is well along, providing an additional basis for assessing the pipeline completion schedule; (2) the State of Alaska has enacted a tax on hydrocarbon reserves to finance its anticipated budget deficits prior to the start of production; (3) Alyeska has announced another upward revision in its estimate of the total cost of the pipeline system – to $6,375 million – for the 1.2 million b/d configuration; (4) Sohio has formally announced its plan for transporting Alaskan crude to the Midwest via a southern pipeline system utilizing idled natural gas transmission facilities; and (5) BP/Sohio have essentially concluded a mammouth $1.75 billion private placement of long-term pipeline debt.

In view of the substantial additional information that has become available in connection with these various developments, a detailed review of the economics of both the pipeline and wellhead production is in order. This report will again utilize the tariff and production profitability models developed in our earlier *Industry Review*. However, the analysis here has been carried a step beyond our "representative" case to show the positions of Arco and Sohio, and their individual recognition of investment tax credit benefits along with the likely effects of reconciling differences in their respective tariff positions. Our approach to the key question of crude prices has also undergone some modification; the $6.00 per barrel case has been eliminated as both unlikely and too pessimistic in terms of real prices to provide an adequate incentive for new exploration projects. Also, a $12.00 case has been included to allow for continued OPEC control of world price levels and/or domestic energy policy considerations, although the base price for our longer term company earnings projections continues to be $10.00 per barrel. This position is predicated on our earlier documented belief that, notwithstanding the historical tendency of oil to underperform inflation following price runups analogous to that of 1973-1974, domestic oil will at least maintain its 1975 average real value in an environment of 5% inflation assumed for the balance of the decade.

As shown in the following table of contents, this report concludes with updates of longer-term earning power and reviews of the financial positions of two of the principal North Slope participants.

(See Table of Contents on following page)

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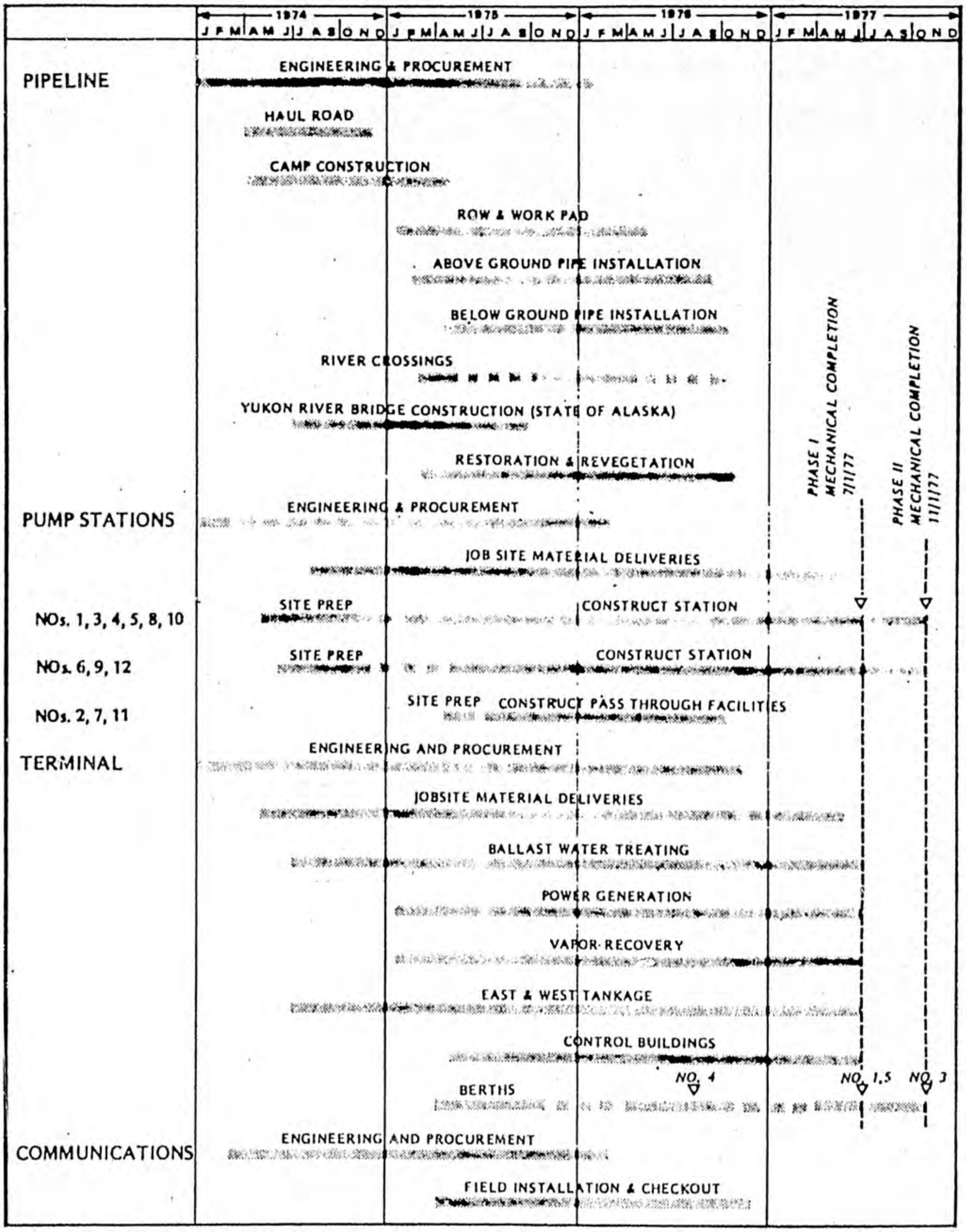
TAPS Construction and Field Development Progress

The following chart shows revisions in the timetable for the principal TAPS construction tasks since our last *Industry Review.*

(See chart on following page)

# Pipeline project schedule



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The main differences between this schedule and that presented earlier are (1) stretchouts in the time required for engineering and procurement at the pump stations and the terminal and (2) jobsite delivery of materials to the pump stations. Even though the Valdez terminal is still the pacing item for an on-time completion of the initial system, none of the revisions to date for individual activities have been sufficient to necessitate a postponement of the mid-1977 target for startup. In fact, the experience so far reemphasizes the point that equal delays in different construction activities are not of equal significance. In the year to date, Alyeska has already shown noteworthy ability to reschedule work and to shift manpower and equipment as requirements change. This flexibility (albeit often obtained at higher costs) should be borne in mind throughout the following review of particular aspects of the project.

Project Management. In June, Alyeska announced a redefinition of the scope of the Bechtel Corporation's duties as the prime contract manager for TAPS construction. Under the new organizational structure, Alyeska assumed full direct supervision of all subcontractors, relegating Bechtel to a project advisory status. Confusion, unnecessarily slow responsiveness to Governmental requirements, and communications difficulties which arose under the prior organizational arrangements were cited by the Alaska State Pipeline Coordinator in a March, 1975 report detailing potential sources of delay in pipeline construction. In assessing the reorganization, it should be recognized that awkwardness incorporated into the basic structure of Alyeska opened the door to top-level organizational difficulties, as evident from the following description by one of the participating companies:

> Eight companies which own Alyeska, operating through the Construction Committee in which each has a representative, must approve major projects, audit performance and agree to furnish funds. This is in contrast to usual joint venture pipeline construction projects where one company is normally the managing partner and where contract responsibility can be given a contractor.

Accordingly, Alyeska's move to streamline the contract management function appears well-conceived, though perhaps somewhat belated. In the view of one Government monitor, it has already improved Alyeska's ability to respond to problems with more timely system design and scheduling modifications.

Valdez Terminal. Good progress is continuing to be made in this critical area. At last report, construction was well underway on 10 out of the 14 crude oil tanks in the eastern tank farm; thus, the goal of completing nine of these tanks by year-end appears easily attainable. The finished tanks will provide 50% of the required crude storage capacity for the phase II configuration (1.2 million b/d) and serve as a positive sign toward completion of the terminal, despite its still-tight schedule. The three ballast tanks needed for phase II are also well along (*ranging from 80% to 92% complete*). The primary current concern regarding the terminals' completion date of mid-1977 is the need for further disposal facilities to handle an extra 5-6 million cubic yards of overburden from excavation. It is both ironic and indicative of the fast changing nature of the situation that, at an earlier stage, the excavation questions at Valdez centered on whether or not there would be *sufficient* overburden material to accommodate landfill requirements for 18 acres of lowland and thus expand the usable land area at the cramped terminal site. Now there is more than enough material, but it is of such low grade that it must be hauled away and better quality fill is being imported to meet the terminal needs. In any case, at recent Congressional oversight hearings on TAPS, Alyeska officials indicated that this disposal of extra overburden might become a pacing item affecting completion of the terminal. However, with significant tankage already well under way, it appears that, at most, this problem would somewhat restrict the volume of initial shipments.

**Pipeline Construction.** Actual pipelaying activities still seem to have the greatest slack in any critical path analysis of the project. Moreover, while there remain several identifiable problems that could cause sufficient stretchouts to make pipelaying the determining factor in the timing of system completion, the responsiveness of Alyeska's contractors to difficulties has been particularly impressive in this area.

For example, as of last spring there had been only limited progress (perhaps 5% of the total effort) in drilling the 75,000 boreholes which will be used to hold the vertical support members (VSM) for approximately 50% of the line that will be elevated. This was primarily due to late delivery of sufficient specially designed augers and spare parts. The delay caused Alyeska to miss its first winter season, which is the ideal time for working on most of the permafrost regions where VSM's will be used.

To regain time, Alyeska quickly obtained additional conventional boring equipment and rescheduled a portion of the work to the summer, even though more complicated drilling procedures were required in some cases. As a result, as of late September, 34,426 VSM's (over 45% of the total) had been installed. Clearly, progress during the past two months has been especially encouraging, suggesting that a learning curve is indeed present. Thus, at present, VSM installation is advancing extremely well, with the availability of spare parts the only continuing concern of Governmental monitors of the project.

In all, the VSM situation provides a good illustration of Alyeska's ability and dedication to make up lost time on certain paths by reallocating manpower and equipment and incurring added costs. River crossings are another area where this approach will be necessary. Through 1975, Alyeska had initially planned to complete a total of 10 crossings. However, slippages during the winter of 1974-1975 delayed commencement of this activity until last April; since that time only three crossings have been completed. The bulk of the remainder have been reprogrammed for the coming winter season. Theoretically, such rescheduling should not seriously affect either costs or overall project timing, since it only shifts project manhours from 1975 to 1976. Importantly, however, if such a change also necessitates the performance of work planned for 1976 in 1977, there is an implicit added cost, since the present union wage scales of most Alyeska contracts only apply until mid-1976.*

A factor that could affect construction progress is the pipeline design modifications necessitated by new information gained in the field. For example, in section three where H.C. Price is the contractor, the terrain has proved highly unpredictable so that early borehole data on soil conditions is not always proving correct. Accordingly, there has been rather extensive redesign, including changes from elevated to buried configurations (and the reverse). In this case, although such work lapsed beyond the slippage allowances in the schedule, time gained in completing the gravel workpad has enabled Price to stay within 2% of its completion target. Nevertheless, the lesson from section three has been that field redesign of pipeline segments can require major adjustments for which allowances will need to be made on occasion.

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**Alyeska's latest cost estimate assumes that a 12% increase in wage rates will be negotiated effective in mid-1976.*

Worker productivity remains a key imponderable for an on-time completion. The experience this summer in selected areas appears to have been encouraging. Though there is undoubtedly a risk in drawing general conclusions, the following is a summary of observations about a few specific activities. In addition to its excellent progress in installing VSM's and terminal tankage, Alyeska has completed its double-jointing program. This involves welding 40-ft. pipe sections in shops at Valdez and Fairbanks to cut in half the amount of welding to be done under much more difficult conditions in the field. More than 625 miles of pipe have been welded at Fairbanks and Valdez. Considering the smoothness with which double jointing operations proceeded, there is little question that the overall efficiency of the welding task has been significantly improved. A second factor that may further assist welding productivity during field installation is the recent authorization by Federal and state monitors that permits welders to produce the first two passes of mainline welding at 10-20 inches per minute versus the 5-8 inches per minute previously allowed.

A less encouraging aspect of worker productivity to date involves attitudes of some of the laborers. Although the Teamsters are the only union to have actually violated a no-strike provision, there have been reports of work slowdowns and the use of numerous "safety meetings," reflecting the inevitable grievances associated with the performance of arduous and sometimes dangerous labor under the added pressure of time. It is all but impossible to gauge the significance of this factor from the available information, but its potential consequences are self-evident and the situation bears close scrutiny in the period ahead.

Of necessity, the foregoing discussion is based on only partial analysis of a highly complex and dynamic project. In fact, the ability of an outside observer to *comprehensively* review the status of TAPS construction will probably remain impossible until actual completion of the system, by which time an examination will be largely of academic interest. Nevertheless, the limited information available does provide a basis for a tentative judgment about the progress of TAPS construction. Our May 1975 report accepted Alyeska's contention that a construction delay beyond mid-1977 was not a foregone conclusion, but also pointed out some of the numerous possibilities for delay and cost escalation as the project unfolded. The validity of this view remains intact; however, one cannot help but be impressed by Alyeska's responsiveness to various difficulties as they arose this past summer – especially its flexibility in work rescheduling in an attempt to attain an on-time completion, notwithstanding the cost trade-off involved. Regarding the trade-off, it should also be noted that the combination of carrying charges in 1977 on about $7.0 billion of pipeline debt and the now established precedent of an Alaskan ad valorem tax on nonproducing reserves provides a powerful incentive to spend currently in order to stay on schedule. With tangible evidence that this is indeed Alyeska's strategy, our inclination is to increase the probability of an on-time completion of the initial *pipeline* configuration but, concurrently, to allow for higher costs than contained in Alyeska's latest control estimates. Based on this expectation along with the companies' last-minute success in getting most of the barges loaded with critical modules for field development to Prudhoe Bay, our production volume assumptions are that throughput will average 600,000 b/d during the second half of 1977, reaching twice that level in early 1978.

Alaskan Reserves Tax

To help alleviate an anticipated fiscal crunch prior to the flow of North Slope oil to market, the State of Alaska has enacted an ad valorem tax (House Bill 297) on hydrocarbon reserves for a two-year period beginning January 1, 1976. Since provision has been made in the bill for a credit of the tax against future severance tax obligations once production begins, the reserves tax can be alternatively viewed as an interest-free advance by the oil companies to the state.

The circumstances surrounding passage of the reserves tax can be traced to the long delay in TAPS completion, along with unrelenting growth of state budgetary expenditures. Under an initial expectation that TAPS would be operational by the fiscal year (FY) ending June 30, 1974, Alaska has been drawing down its $900 million lease bonus fund (garnered at the 1969 sale of Prudhoe Bay leases) to cover its budget shortfalls, on the belief that the receipt of oil royalty revenues starting in 1974 would be sufficient to restore the lease sale fund to its original size. At the same time, the existence of the $900 million fund provided impetus for an expansion of Government spending. Thus, Alaska's general fund budget rose from $168 million in FY 1970 to $364 million in FY 1974. Accordingly, by January 1975, the lease sale fund had shrunk to $504 million. However, of that latter amount, only $311 million was held as liquid investments (the balance was in relatively illiquid Alaskan loans and mortgages as well as deposits in Alaskan banks).

In FY 1975, general fund expenditures of about $540 million exceeded approximate revenue receipts of $340 million, necessitating a bonus fund drawdown of $200 million for the entire year, or to about $370 million by June 30. Based on an estimated general fund budget of $620 million for FY 1976, the state anticipates that the resulting budget deficit and already mandated loan programs will require an additional $350 million, against which, the sale of remaining lease bonus monies – both investments and deposits – should net only $300 million. Hence, beginning in FY 1976, a significant cash crunch is foreseen. Latest projections indicate that the state will need $400 million in total additional revenue for the years 1976-1978 if the pipeline is completed on schedule (July 1, 1977). A six-month delay would boost the amount needed to $600 million and a full-year delay to $850 million.

In attempting to meet the anticipated cash flow shortfall, Alaska's legislators had to choose from among the following mix of revenue-producing measures: (1) budget cuts; (2) sale of loans and mortgages from the general fund; (3) oil and gas lease sales; (4) advance sales of royalty oil and gas; (5) general tax increases; (6) ad valorem taxation of oil and gas reserves; and (7) short-term borrowing. Some of these alternatives involve limitations with respect to either the amount of revenue generated or the time frame for receipt of additional revenue. For example, given Alaska's limited economic base, it would be difficult to raise much of the required $400 million and still retain an equitable tax system. By eliminating some of the loopholes in the Alaskan corporate tax that exist because of "piggybacking" the Federal income tax and increasing the natural gas severance tax from 4% to 10%, an additional $20 million in revenue is expected. The final alternative, short-term borrowing, would require an amendment to the state constitution to permit borrowing for operational purposes beyond a one-year period. Unfortunately, an enabling constitutional amendment could not be voted upon until the next general election in November, 1976 – too late to meet the initial fiscal crunch.

Among the other available alternatives, an ad valorem tax on oil and gas reserves was selected as the principal ameliorative for maintaining fiscal solvency prior to pipeline startup. It is interesting to note that Alaska opted for a reserves tax (HB 297) over the opposition of one of its key consultants, Lipton, Levy & Associates, who favored a Beaufort Sea lease sale. As enacted, the reserves tax is similar in structure to existing statutes in California and Texas, except for the provision of a tax credit against severance tax payments once oil production starts. In fact, the provision has led a legal consultant of the state to conclude that HB297 may violate the due process and equal protection clauses of the 14th amendment to the U.S. Constitution. In effect, Alaska is seen as coercing the lending to it of monies on an interest-free basis by lessees of state oil and gas leases. The legal consultant believes that to convert HB 297 from a mandatory lending statute into a genuine tax law, it will be necessary to modify its tax credit provisions so as to produce a substantial amount of new and independent tax revenue. While a potential legal challenge cannot be ruled out, it is difficult to see how the oil companies could benefit by challenging the reserves tax since it can be easily converted into an independent revenue raising device by simply eliminating the severance tax credit.

As far as the actual mechanics of the reserves tax are concerned, it relies on the income appraisal method of oil and gas property valuation to determine the fair market value of the property using discounted present value techniques. A number of difficult estimation problems arise in any attempt to arrive at the value of the leasehold or other mineral interest involved, including: (1) reserves in-place; (2) production rates; (3) out-of-pocket operating expenses; (4) prices; and (5) discount rate. As such, an ad valorem tax on oil and gas properties can be highly arbitrary in nature.

In early 1975, a study commissioned to assess, as of January 1, 1976, the value of oil and gas contained in the Sadlerochit formation of the Prudhoe Bay field arrived at a figure of $11.5 billion. This analysis assumed that oil production would begin at 1.2 million b/d in 1978, and rise to a peak rate of 1.8 million b/d in 1981. A wellhead price of $4.93 per barrel was used initially, which subsequently rises to $7.50 per barrel by 1980 based on a $10 per barrel refinery price. For natural gas, production was assumed to begin in 1982 at a rate of 1 billion cubic feet per day, with an eventual peak of 3 billion cubic feet per day in 1997. A wellhead price of 50¢ per Mcf was used. After deducting *out-of-pocket expenses* – capital expenditures, lifting costs, property taxes -- from gross revenue, the resulting pretax income figure was discounted at an 18% annual, mid-year rate. Of the resulting $11.5 billion appraised value, $10.8 billion was attributable to oil alone.

The rate of levy for the tax year beginning January 1, 1976 is 20 mills (2¢) per dollar of assessed valuation, payable by June 30, 1976. The Alaskan legislature will annually set the rate of levy, but it cannot exceed 20 mills. A reading of the exemption and credit provisions of the tax would appear to limit its impact primarily to the Sadlerochit formation and several small gas fields in the Kenai area.* Using the above-derived valuation for the Sadlerochit, the first year tax would amount to $230.3 million.** The legislation also provides for a system of development incentive credits by which the affected oil companies will receive, beginning in

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**To the extent that severance taxes paid on a producing property for a 12-month period prior to the tax payment date equal or exceed the reserve tax assessment, no payment is required. Also, a property wholly or partially underlying a discovery well is exempted from the tax for a period of five years beginning on the date of the completion, suspension, or abandonment, whichever occurs first.*

*** Until a permit or license is issued for construction of a natural gas transmission line, natural gas reserves at Prudhoe Bay are exempted from the tax. The natural gas exemption reduces tax revenues by $14 million, or to $216 million.*

1978, a reduction in severance taxes equal in amount to total reserves tax payments. However, the development incentive credit cannot exceed 50% of severance taxes computed on a monthly basis – a limitation which effectively increases the payback period to some 4½ years.

Coming as it does when the major Prudhoe Bay leaseholders face already significant TAPS and field development expenditures, the reserves tax has imposed yet another financing burden on the oil industry, especially Sohio. As such the tax joins the minimum cents-per-barrel severance tax as a seemingly inequitable revenue-producing measure and a source of anxiety to the companies in terms of possible follow-on tax measures. Regarding the latter point, the legislature's refusal to adopt the so-called "Sohio amendment," which would have allowed a reserves tax credit against royalty rather than severance tax, is indicative of Alaska's strategy of taking a portion of its royalty oil entitlement in kind to establish the regulatory functions of the Alaska Pipeline Commission.*

The preceding discussion is not meant to alarm the reader, but only to reiterate the risk of viewing tax terms at any Governmental level as fixed. In fact, a bill introduced during the past session of the Alaskan Senate, (Senate Bill 295), sought to raise the oil severance tax from a maximum of 8% of wellhead value to 12%. *Moreover, it should be noted that this latter measure is likely to be resurrected again during the next legislative session starting in January,* and thus bears close monitoring. Nevertheless, given Alaska's future cash flow stream from the North Slope, as well as the need to allow adequate economic incentive in order to maximize long-term oil development opportunities, an overly cautious attitude regarding the future relationship between Alaska and the oil companies does not appear warranted at this time. To illustrate the financial benefits that will accrue to Alaska once North Slope oil production begins, the following table depicts our derivation of potential sources of revenue under a variety of the throughput rates using a $10 per barrel West Coast price. For comparison purposes, general fund budget expenditures are projected to reach about $1.2 billion in 1980.

(See table on following page)

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**By taking a portion of its royalty oil in kind, either at some intermediate point or at Valdez, Alaska will have established an intrastate movement of North Slope crude, thus enabling its Pipeline Commission to assert regulatory control, including tariff rates, over the intrastate movements. Also, the state is presently a party to an ICC determination, ex parte 238, which involves questions relating to what items shall go into the rate base and the allowed rate base return.*

**State of Alaska Revenues**
(In millions)

| | Pipeline Throughput | | |
|---|---|---|---|
| | 1.2 mil. b/d | 1.5 mil. b/d | 2.0 mil. b/d |
| Ad valorem taxes (a) | $178 | $183 | $177 |
| Severance taxes (b) | 201 | 252 | 375 |
| Royalty | 261 | 376 | 586 |
| Income tax: | | | |
| Pipeline | 69 | 73 | 74 |
| Wellhead | 131 | 196 | 303 |
| Total income tax | 200 | 269 | 377 |
| Total revenues | $840 | $1,080 | $1,515 |

*(a) Includes ad valorem taxes on field development facilities. Assessed valuation is assumed to be based on the gross cost of the main Prudhoe Bay field facilities ($2.375 billion) less amortization of investment at the rate of 24 ¢ per barrel on a unit-of-production basis. Because of the unavailability of data related to the cost of facilities required to ultimately develop the Lisburne and Kuparuk formations, an ad valorem tax estimate has not been made for this potential component of field development spending.*

*(b) Before deduction of severance tax credits, over a 4½ year period, amounting to a maximum of $474 million based on a preliminary appraisal of the oil reserves contained in the Sadlerochit formation.*

## *Economics of Prudhoe Bay Production*

### Pipeline Economics

On June 19, 1975, Alyeska Pipeline Service Company announced a revised control estimate of $6.375 billion for the construction of TAPS to an initial design capacity of 1.2 million b/d. Although the revised figure includes provision for escalation of the costs of labor,* material, equipment, and consumables, a contingency allowance is not specifically included in the new control estimate.** However, Alyeska did suggest to the TAPS owners that a contingency allowance of 5% might be added to the control estimate to provide for unforeseen cost changes during the remainder of the construction period. Alyeska has also estimated that the cost to expand TAPS from 1.2 million to 2 million b/d would approximate $850 million, of which $490 million would be required to expand system capacity to an intermediate level of 1.6 million b/d.***

In full cognizance of the TAPS construction cost progression to date and the aforementioned tradeoff between on-time project completion and final system cost, our projections allow for a final cost of 10% above Alyeska's latest estimate of total project cost.

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**A Project Labor Agreement entered into with the major international and local unions involved in the project has established wage rates only for the period through June 30, 1976.*

***It might be recalled that Alyeska's previous control estimate of $5.98 billion last October incorporated a $424 million contingency allowance.*

****Expansion of TAPS to an intermediate capacity level between 1.2 and 2.0 million b/d would require an amendment to the TAPS Agreement.*

The following analysis of pipeline earnings and tariffs includes a "representative" case applicable to all the TAPS participants – similar to the approach used in our May *Industry Review* -- and individual computations for ARCO Pipeline Company and Sohio Pipe Line Company. The latter analysis illustrates the variable tariffs that arise under the undivided interest form of ownership due to cost of capital differences among the TAPS owners and individual company preferences regarding usage of debt and equity in financing the project.

Working assumptions for our "representative" case include the following:

(1) Construction of TAPS to an initial design capacity of 1.2 million barrels per day will cost $7,012.5 billion. Expansion of the system to 2 million b/d will cost an additional $935 million.

(2) TAPS will be financed (including capitalized interest) utilizing 85% borrowed funds at an average borrowing rate of 9.5%.

(3) Capitalized interest charges during construction are estimated at $1.52 billion, of which $1.47 billion is applicable to the 1.2 million b/d system configuration.

(4) Capitalized interest will be amortized over a 25-year period. Amortization of debt used to finance TAPS (exclusive of refinancings) will not begin in a time frame relevant to the scope of the analysis included herein.

(5) The main pipeline system assets placed in service in mid-1977 will be depreciated over a 35-year period for ICC purposes. For IRS filings, a 22-year sum-of-the-years'-digits method will be employed, with a possible requirement that any resulting tax deferrals be flowed through as a reduction in pipeline tariff. As additional pipeline capacity is added beyond mid-1977, a shorter depreciable life is used for assets associated with the expanded capacity (mainly pump stations) to conform with the remaining depreciable life of the main pipeline system assets.

(6) Ad valorem taxes of 20 mills (2¢) per dollar of assessed valuation will be collected by the State of Alaska on qualifying pipeline system assets.

(7) Current ICC procedures will govern rate base determination. A return of up to 7% of net pipeline valuation* is allowable in posting ICC tariffs under the terms of the 1941 Consent Decree.

On the basis of the foregoing assumptions, the following table depicts, both for book and tax purposes, pipeline earnings and required tariffs for various throughput levels.

(See table on following page)

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* *Assumed to be $7.72 billion upon initial completion of TAPS.*

### Pipeline Earnings and Tariffs – Ex ITC
(In millions)

| | 1.2 million b/d | | 1.5 million b/d | | 2.0 million b/d (a) | |
|---|---|---|---|---|---|---|
| | Book | Tax | Book | Tax | Book | Tax |
| Revenues | $2,267 | $2,267 | $2,388 | $2,388 | $2,413 | $2,413 |
| Operating costs | 50 | 50 | 60 | 60 | 70 | 70 |
| Ad valorem taxes(b)(c) | 130 | 130 | 137 | 137 | 136 | 136 |
| Amortization of capitalized interest | 59 | 59 | 60 | 60 | 61 | 61 |
| Interest expense | 682 | 682 | 724 | 724 | 748 | 748 |
| Depreciation | 200 | 610 | 216 | 631 | 228 | 611 |
| Total expenses | 1,121 | 1,531 | 1,197 | 1,612 | 1,243 | 1,626 |
| Pretax earnings | 1,146 | 736 | 1,191 | 776 | 1,170 | 787 |
| Income taxes (d): | | | | | | |
| Cash | 389 | 389 | 411 | 411 | 416 | 416 |
| Deferred | 217 | – | 219 | – | 203 | – |
| ICC allowable return | $ 540 | $ 347 | $ 561 | $ 365 | $ 551 | $ 371 |

| | Case A | Case B | Case A | Case B | Case A | Case B |
|---|---|---|---|---|---|---|
| Gross revenues required | $2,050 | $2,267 | $2,169 | $2,388 | $2,210 | $2,413 |
| Oil shipments (million barrels) | 438 | 438 | 548 | 548 | 730 | 730 |
| Required tariff per barrel | $4.68 | $5.18 | $3.96 | $4.36 | $3.03 | $3.31 |

*(a) Capacity of 1.5 million and 2 million b/d is assumed to be reached one and three years, respectively, after completion of the first stage.*

*(b) 2% of the remaining net tangible investment in pipeline facilities after approximately $500 million of properties transferred to the State of Alaska (Yukon River bridge, certain airfields, and the Alaskan highway) are deducted.*

*(c) Not including amortization of capitalized ad valorem taxes of $138.6 million incurred through mid-1977.*

*(d) Includes statutory Alaskan income tax of 9.36%.*

*Case A: With flow-through.*
*Case B: Without flow-through.*

(See table on following page)

### Pipeline Earnings and Tariffs – Including ITC
(In millions)

| | 1.2 million b/d | | 1.5 million b/d(a) | | 2.0 million b/d(a) | |
|---|---|---|---|---|---|---|
| | Book | Tax | Book | Tax | Book | Tax |
| Revenues | $2,267 | $2,267 | $2,388 | $2,388 | $2,413 | $2,413 |
| Operating costs | 30 | 50 | 60 | 60 | 70 | 70 |
| Ad valorem taxes (b)(c) | 130 | 130 | 137 | 137 | 136 | 136 |
| Amortization of capitalized interest | 59 | 59 | 60 | 60 | 61 | 61 |
| Interest expense | 682 | 682 | 724 | 724 | 748 | 748 |
| Depreciation | 200 | 610 | 216 | 631 | 228 | 611 |
| Total expenses | 1,121 | 1,531 | 1,197 | 1,612 | 1,243 | 1,626 |
| Pretax earnings | 1,146 | 736 | 1,191 | 776 | 1,170 | 787 |
| Income taxes: | | | | | | |
| Federal - cash | | | | | | |
| Pre-ITC | 320 | 320 | 338 | 338 | 342 | 342 |
| ITC | (406)(d) | (406)(d) | (25) | (25) | – | – |
| Federal-deferred | 217 | | 219 | | 203 | – |
| State @ 9.36% | 69 | 69 | 73 | 73 | 74 | 74 |
| Total income taxes | 606 | 389 | 630 | 411 | 619 | 416 |
| ICC allowable return | 540 | $ 347 | $ 561 | $ 365 | $ 551 | $ 371 |
| ICC allowable return plus ITC | $ 946 | – | $ 586 | – | – | – |
| | Case A | Case B | Case A | Case B | Case A | Case B |
| Gross revenues required | $2,050 | $2,267 | $2,169 | $2,388 | $2,210 | $2,413 |
| Oil shipments (million barrels) | 438 | 438 | 548 | 548 | 730 | 730 |
| Required tariff per barrel | $4.68 | $5.18 | $3.96 | $4.36 | $3.03 | $3.31 |

*(a) Capacity of 1.5 million and 2 million b/d is assumed to be reached one and three years, respectively, after completion of the first stage.*

*(2) 2% of the remaining net tangible investment in pipeline facilities after approximately $500 million of properties transferred of the State of Alaska (Yukon River bridge, certain airfields, and the Alaskan highway) are deducted.*

*(c) Not including amortization of capitalized ad valorem taxes of $138.6 million incurred through mid-1977.*

*(d) While the indicated level of ITC benefit exceeds the statutory limit ($25,000 plus 50% of taxes payable) on a project stand-alone basis, the assumed availability of sufficient income from other sources should allow each of the TAPS participants, except for BP and Sohio, to fully recognize this benefit on a current basis.*

*Case A: With flow-through.*

*Case B: Without flow-through.*

Given that the State of Alaska will undoubtedly opt to receive a portion of its 12½% royalty oil entitlement in kind, with an attendant need for common carrier transportation services, a strong likelihood exists that the state will elect to file a contested rate application with the ICC opposing the indicated maximum tariffs shown above.* To illustrate the impact of

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*Since Alaska's major sources of revenue are directly tied to the Prudhoe Bay field wellhead price, a strong bias exists in favor of minimizing transportation charges.*

a lower allowed ICC return, pipeline earnings under the 1.2 million b/d throughput level would fall to $386 million and result in a revised flow-through tariff of $3.94 per barrel under the assumption of a 5% allowable return. *For companies whose interests in production roughly approximate their interest in TAPS, the overall impact on earnings is negligible, since lower pipeline earnings are largely offset by the benefits of a higher wellhead price.*

### Allowable Tariff Positions of Individual Companies

In addition to the possibility of a contested rate application, there are other circumstances under which actual pipeline tariffs could vary from the "representative" 7% return case developed above. Under the individual interest form of pipeline ownership, each company with a stake in TAPS will individually arrange and reflect its portion of the pipeline debt financing on its own balance sheet and will file separate tariff schedules with the Interstate Commerce Commission based on a proportionate share of TAPS' overall operations. As mentioned previously, this approach results in differences in the maximum allowable tariffs for individual companies due to variations in (1) the cost of capital, (2) the debt/equity mix, and (3) the rate at which debt is taken down for pipeline financing. To illustrate these differences, the following calculations have been developed for the specific cases of ARCO Pipeline Company and Sohio Pipe Line Company, using the approach already outlined for the "representative" example above, along with the additional working assumptions outlined below:

(1) Operating costs, an valorem taxes, and depreciation are each based on the company's ownership percentage applied to the appropriate totals for these items in the "representative" case.

(2) ARCO Pipeline's TAPS financing is assumed to consist of 90% debt and 10% equity, with all of the remaining requirements for the latter* contributed during 1977. Sohio Pipe Line's capitalization mix will be 85% debt and 15% equity, with the balance of the equity contributed after mid-1976.**

(3) Average pipeline borrowing rates of 9% and 10% are anticipated for ARCO and Sohio, respectively.

(4) Capitalized interest and commitment fees during construction will be $275 million for ARCO Pipeline, of which $268 million is attributable to the 1.2 million b/d configuration. For Sohio Pipeline, the corresponding amounts will be $465 million and $445 million.

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**On March 31, 1975, ARCO Pipeline's long term capitalization totaled $695.4 million, of which $155.4 million was stockholders' equity. Of the latter amount, $75 million is assumed to be creditable as an equity contribution toward TAPS, leaving a 1977 requirement for an additional $105 million.*

***At year-end 1974, Sohio Pipe Line's equity was $42 million. To achieve an 85%/15% debt equity mix in 1977, another $308.7 million will be required during 1976-1977. A portion of this requirement can be met by converting existing parent company advances of $110 million to equity contributions.*

## ARCO Pipeline Earnings and Tariffs – Ex ITC

| | 1.2 million b/d | | 1.5 million b/d | | 2.0 million b/d (a) | |
|---|---|---|---|---|---|---|
| | Book | Tax | Book | Tax | Book | Tax |
| Revenues | $468 | $468 | $492 | $492 | $571 | $571 |
| Operating costs | 11 | 11 | 13 | 13 | 17 | 17 |
| Ad valorem taxes | 27 | 27 | 29 | 29 | 33 | 33 |
| Amortization of capitalized interest | 11 | 11 | 11 | 11 | 12 | 12 |
| Interest expenses | 141 | 141 | 150 | 150 | 178 | 178 |
| Depreciation | 42 | 128 | 45 | 133 | 55 | 146 |
| Total expenses | 232 | 318 | 248 | 336 | 295 | 386 |
| Pretax earnings | 236 | 150 | 244 | 156 | 276 | 185 |
| Income taxes | | | | | | |
| Cash | 79 | 79 | 83 | 83 | 98 | 98 |
| Deferred | 46 | — | 46 | — | 48 | — |
| ICC allowable return | $111 | $ 71 | $115 | $ 73 | $130 | $ 87 |
| | Case A | Case B | Case A | Case B | Case A | Case B |
| Gross revenues required | $422 | $468 | $446 | $492 | $523 | $571 |
| Oil shipments (mil. barrels) | 92 | 92 | 115 | 115 | 175 | 175 |
| Required tariff per barrel | $4.59 | $5.09 | $3.88 | $4.28 | $2.99 | $3.26 |

*Case A: With flow-through.*
*Case B: Without flow-through.*

*(a) Assumes that ARCO Pipeline's interest in TAPS increases to 24% following implementation of a nomination to expand system throughput to 2 million b/d to accommodate incremental North Slope production. The additional cost to ARCO Pipeline involved in the reallocation of ownership interests is estimated by the writer to amount to $236 million exclusive of unamortized capitalized interest.*

(See table on following page)

Sohio Pipe Line Earnings and Tariffs – Ex ITC

| | 1.2 million b/d | | 1.5 million b/d | | 2.0 million b/d | |
|---|---|---|---|---|---|---|
| | Book | Tax | Book | Tax | Book | Tax |
| Revenues | $756.5 | $756.5 | $798.2 | $798.2 | $795.6 | $795.6 |
| Operating costs | 16.7 | 16.7 | 20.0 | 20.0 | 23.3 | 23.3 |
| Ad valorem taxes | 43.3 | 43.3 | 45.7 | 45.7 | 45.3 | 45.3 |
| Amortization of capitalized interest | 17.8 | 17.8 | 18.3 | 18.3 | 18.6 | 18.6 |
| Interest expense | 235.7 | 235.7 | 250.7 | 250.7 | 247.5 | 247.5 |
| Depreciation | 66.7 | 203.4 | 72.0 | 210.4 | 76.0 | 203.4 |
| Total expenses | 380.2 | 516.9 | 406.7 | 545.1 | 410.7 | 538.1 |
| Pretax earnings | 376.3 | 239.6 | 391.5 | 253.1 | 384.9 | 257.5 |
| Income taxes | | | | | | |
| Cash | 126.7 | 126.7 | 133.9 | 133.9 | 136.2 | 136.2 |
| Deferred | 72.4 | – | 73.2 | – | 67.4 | – |
| ICC allowable return | $177.2 | $112.9 | $184.4 | $119.2 | $181.3 | $121.3 |
| | Case A | Case B | Case A | Case B | Case A | Case B |
| Gross revenues rquired | $684.1 | $756.5 | $725.0 | $798.2 | $728.2 | $795.6 |
| Oil shipments (mil. barrels) | 146 | 146 | 182.7 | 182.7 | 243.4 | 243.4 |
| Required tariff per barrel | $4.69 | $5.18 | $3.97 | $4.37 | $2.99 | $3.27 |

*Case A: With flow-through.*
*Case B: Without flow-through.*

From this analysis, it is evident that at intermediate throughput levels, ARCO Pipeline's maximum allowable tariff would be 8¢-9¢ per barrel less than the "representative" case, largely due to the company's advantageous cost of capital. In Sohio's case, the higher relative capital costs obviously result in a greater allowable tariff than for ARCO, but the interesting point is that the company's intended use of proportionally more equity* in the pipeline should partially offset this effect so that Sohio's calculated per barrel transportation postings should closely approximate the "representative" case.

There are circumstances under which the foregoing differences could become significant. In particular, during a period of less than full pipeline utilization,** actual tariffs would be likely to gravitate toward the maximum levels of the lower cost suppliers of transportation services as producers exercise nominating preferences for such capacity. This tendency would thus preclude the full realization of the maximum allowable ICC return on pipeline investments of companies with the highest rate bases.

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**For comparison, it appears that Exxon's and Mobil's TAPS pipeline capitalizations will consist of 10% or less equity.*

***It is possible to see this occuring as capacity is expanded to 2.0 million b/d and depending on the degree of future exploratory success and the timing of the development of the Lisburne and Kuparuk formations.*

To better demonstrate the tariff-setting mechanism here, it should also be noted that the *potential* for variation in per barrel tariff is actually wider than indicated by our calculations for ARCO and Sohio. For example, not long ago one owner of a fairly small interest in TAPS was reportedly contemplating funding its entire share of pipeline costs with equity, thus foregoing any rate base credits for interest expense and capitalized interest during construction. Holding all other assumptions constant, the effect of using this financing mix for TAPS would be to reduce the maximum ICC allowed tariff to $2.75 per barrel for Case A at 1.2 million b/d of throughput, fully $1.94 below that of Sohio. This is clearly an extreme example with at least some chance that this company will ultimately more closely conform its financing strategy to that of other TAPS owners. Since only a few percentage points of transportation capacity are involved, the downward pulling effect from this one participant would still be limited. However, the comparison helps to illustrate the likely mechanism for tariff determination, and is one more factor dictating caution in simply using a tariff based on an ICC allowed 7% return for a given company.

The investment tax credit is another factor that could give rise to differences in individual company tariffs if such benefits are flowed-through in a manner similar to ICC treatment of deferred taxes. As indicated in both the "representative" tariff analysis and the Financial Position Review sections for Arco and Sohio, ITC benefits will be quite significant for leading TAPS participants. However, due to the differing abilities of Sohio and Arco to utilize portions of their TAPS and field development ITC prior to pipeline startup under the "qualified progress payment" option,* it is clear that a company's ITC benefits available at commencement of operations will not simply be a function of TAPS and field ownership percentages. Because of the inherently greater difficulty in predicting what Sohio will be able to realize in ITC benefits at given throughput levels, we have excluded this factor from the analysis in the preceding table.

**Prudhoe Bay Field Profitability**

In estimating unit producing profitability, the following assumptions have been made:

(1) The landed crude oil price on the West Coast will fall within a broad range of $8-$12 per barrel toward the end of the decade.

(2) With additional exploratory activity on the North Slope, delineation of the Lisburne and Kuparuk oil pools and any new pools could contribute sufficient additional reserves to enable pipeline throughput to reach 2 million b/d by mid-1980.

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**Under the Tax Reduction Act of 1975, a participant in a project which has a leadtime of more than two years may elect to recognize its ITC associated with qualified expenditures in a given year on a ratable basis over a period of up to five years from 1975. Both ARCO and Sohio have adopted this treatment of ITC, but it appears that while ARCO should be able to fully realize such benefits currently, Sohio may be unable to fully utilize these credits in 1975 and 1976, resulting in its having proportionally greater ITC carryforwards available in 1977.*

(3) Production operating costs (lifting, depreciation, and amortization) will approximate 44¢ per barrel for the Sadlerochit formation* and 97¢ for possible incremental production from the Lisburne, Kuparuk, and any other as yet undefined pools. The latter figure involves an admittedly arbitrary assumption that the unit profitability of oil pools other than the Sadlerochit will, at a *minimum*, fall 25¢ per barrel below the comparable figure for the Sadlerochit; this reflects significantly lower per well producibility and higher drilling and completion costs on a unit-of-production amortization basis.

(4) Royalty payments (12.5%), severance taxes (8%), and ad valorem taxes will approximate 22% of wellhead value, except that severance taxes, as currently indicated by the Bureau of Labor Statistics' index of wholesale crude prices, would be a minimum of 46¢ per barrel for a 10,000 b/d well (34¢ per barrel for a 1,000 b/d well) before provision for credit against the ad valorem tax on in-place reserves.

(5) Wellhead profits will be taxed at a full 48% Federal rate (before investment tax credits related to field development expenditures) and a 9.36% Alaskan rate. Because of differing individual company treatment of ITC under the terms of the Tax Reduction Act of 1975, the unit profitability figures shown below do not include provision for this credit. (See Financial Position Review section for a discussion of the individual treatment by Arco and Sohio).

Incorporating the foregoing assumptions into projections for unit producing profits, the next table shows their impact under the three throughput configuration cases.

(See table on following page)

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**Field development costs are presently estimated at $2.375 billion to reach producibility of 1.5 million b/d versus $1.9 billion in our earlier assessment. Field development expenditures include $100 million for a power station and $350 million for a gas compression plant. A portion of the cost of these facilities is thus applicable to natural gas production – on a Btu equivalent basis, total field development costs work out to 24¢ per barrel for oil and 1¢ per Mcf for natural gas.*

## Unit Profits

**Pipeline Throughput: 1.2 million b/d**

| West Coast price | | $8.00 | | $10.00 | | $12.00 |
|---|---|---|---|---|---|---|
| Pipeline tariff | $4.68 | | $4.68 | | $4.68 | |
| Tanker costs (a) | 0.55 | | 0.55 | | 0.55 | |
| Total transportation costs | | 5.23 | | 5.23 | | 5.23 |
| Wellhead price | | 2.77 | | 4.77 | | 6.77 |
| Royalty, severance and misc. | 0.85 | | 1.13 | | 1.49 | |
| Lifting, depreciation & amortization | 0.44 | | 0.44 | | 0.44 | |
| Total producing costs | | 1.29 | | 1.57 | | 1.93 |
| Pretax profit | | 1.48 | | 3.20 | | 4.84 |
| Income taxes at 52.9% | | 0.78 | | 1.69 | | 2.56 |
| Net income per barrel | | $0.70 | | $ 1.51 | | $ 2.28 |

**Pipeline Throughput: 1.5 million b/d**

| West Coast price | | $8.00 | | $10.00 | | $12.00 |
|---|---|---|---|---|---|---|
| Pipeline tariff | $3.96 | | $3.96 | | $3.96 | |
| Tanker costs (a) | 0.55 | | 0.55 | | 0.55 | |
| Total transportation costs | | 4.51 | | 4.51 | | 4.51 |
| Wellhead price | | 3.49 | | 5.49 | | 7.49 |
| Royalty, severance and misc. | 0.95 | | $1.23 | | $1.65 | |
| Lifting, depreciation and amortization | 0.44 | | 0.44 | | 0.44 | |
| Total producing costs | | 1.39 | | 1.67 | | 2.09 |
| Pretax profit | | 2.10 | | 3.82 | | 5.40 |
| Income taxes at 52.9% | | 1.11 | | 2.02 | | 2.86 |
| Net income per barrel | | $0.99 | | $ 1.80 | | $ 2.54 |

**Pipeline Throughput: 2.0 million b/d**

| West Coast price | | $8.00 | | $10.00 | | $12.00 |
|---|---|---|---|---|---|---|
| Pipeline tariff | $3.03 | | $3.03 | | $3.03 | |
| Tanker costs (a) | 0.55 | | 0.55 | | 0.55 | |
| Total transportation costs | | 3.58 | | 3.58 | | 3.58 |
| Wellhead price | | 4.42 | | 6.42 | | 8.42 |
| Royalty, severance and misc. (b) | 1.05 | | 1.41 | | 1.85 | |
| Lifting, depreciation & amortization(c) | 0.57 | | 0.57 | | 0.57 | |
| Total producing costs | | 1.62 | | 1.98 | | 2.42 |
| Pretax profit | | 2.80 | | 4.44 | | 6.00 |
| Income taxes at 52.9% | | 1.48 | | 2.35 | | 3.17 |
| Net income per barrel | | $1.32 | | $ 2.09 | | $ 2.83 |

*(a) Includes 5¢ per barrel for the TAPS Liability Fund.*

*(b) For the $8 per barrel case, severance tax is a weighted average of 46¢ per barrel for 1,500,000 b/d and 34¢ per barrel for 500,000 b/d. The cents-per-barrel minimum severance tax is superseded by the 8% of wellhead maximum under the $10 and $12 per barrel cases.*

*(c) 1,500,000 b/d at 44¢ per barrel and 500,000 b/d at 97¢ per barrel.*

## *Financial Position Review*

### Financial Position Review – The Standard Oil Company (Ohio)

In our May, 1975 *Basic Report* on this company, five contingencies were identified, which could result in significant additional financing requirements. These included (1) construction delays, (2) system cost revisions, (3) early commitment to expansion of throughput beyond 1.2 million barrels daily (4) enactment of an Alaskan reserves tax, and (5) a decision to proceed with a trans-U.S. pipeline to move North Slope oil to the Midwest. With three of these factors now realities, a review of Sohio's financing needs for the critical 1975-1977 period is in order.

The next table summarizes Sohio's past and projected North Slope expenditures for each increment of pipeline capacity and for development of the main field based on our revisions of estimates for system costs.

**Estimated North Slope Pipeline & Development Costs**
(In millions)

| | Expended Through Mid-1975 | Approximate Remaining Obligation | Total |
|---|---|---|---|
| TAPS: | | | |
| To 1.2 million b/d | $ 816 | $1,522 | $2,338(a) |
| To 2.0 million b/d | — | 312 | 312(b) |
| Capitalized pipeline interest | 84 | 381 | 465 |
| TAPS total | $ 900 | $2,215 | $3,115 |
| Field development | 517 | 749 | 1,266(c) |
| Tankers | — | 720 | 720(d) |
| Total North Slope (c) | $1,417 | $3,684 | $5,101 |

*(a) 33.34% of Alyeska's latest cost estimate($6,375 million) escalated an additional 10% to $7,012.5 million.*

*(b) Not including additional costs associated with possible realignment of TAPS ownership interests. Thus, 33.34% of Alyeska's latest cost estimate ($850 million) increased by 10% to $935 million.*

*(c) 53.3% of an estimated $2,375 million for field development costs necessary to reach 1.5 million b/d.*

*(d) Covers construction contracts for eight tankers which the company is in the process of assigning to others in return for charter or lease arrangements.*

In all, Sohio's expenditures through mid-1975 amount to just over 32% of the above estimated total expenditures for the North Slope project (excluding chartered tankers). The field development costs shown are directly proportional to our estimate of Sohio's ultimate share of the main unit's reserves. While it is normal that unitized field development costs are equalized, there is no such agreement in this instance. Accordingly, during unitization negotiations, Sohio will be seeking some adjustment against its share of additional costs for development of the eastern half of the field to reflect the company's early development expenditures at lower costs due to lower prices for labor and materials. Since the difference in development costs for the field's two halves could well exceed $200 million, even partial compensation for Sohio's share of this excess may be a meaningful adjustment in the field development funding requirements shown here.

The financial requirements picture has been further complicated by several other contingencies identified in our May *Basic Report.* These include the company's Alaskan reserves tax obligations for 1976 and 1977 and its preliminary planned expenditures toward a trans-U.S. pipeline to move Alaskan crude into Texas. These considerations have been included in the following revised projections which show the timing and magnitude of Sohio's remaining balance sheet financing requirements through 1977.

**Standard Oil (Ohio)**
**Financing 1975-1977**
(In millions)

| | 1975 | | | | |
|---|---|---|---|---|---|
| Sources: | Actual First Half | Estimated Second Half | 1976 | 1977 | Cumulative Tot. mid-1975-1977 |
| Net income plus deferred taxes (a) | $ 85.0 | $ 95.0 | $ 190.0 | $448.6 | $ 733.6 |
| Depreciation, depletion, and amort. | 39.6 | 38.4 | 85.0 | 130.4 | 253.8 |
| Funds from operations | $124.6 | $133.4 | $ 275.0 | $579.0 | $ 987.4 |
| Less: | | | | | |
| Debt maturities | 3.4 | 0.6 | 11.0 | 18.0 | 29.6 |
| Dividends | 24.9 | 25.1 | 51.0 | 51.0 | 127.1 |
| Available from operations | $ 96.3 | $107.7 | $ 213.0 | $510.0 | $ 830.7 |
| Uses: | | | | | |
| TAPS outlays | $364.0 | $465.0 | $ 863.7 | $300.3 | $1,629.0 |
| Capitalized pipeline interest | 28.0 | 54.0 | 196.3 | 120.5 | 370.8 |
| Field development | 145.0 | 190.0 | 367.0(b) | 192.0 | 749.0 |
| Total North Slope expenditures | $537.0 | $709.0 | $1,427.0 | $612.8 | $2,748.8 |
| Other expenditures (c) | | | | | |
| Existing activities | 81.0 | 141.0 | 115.0 | 75.0 | 331.0 |
| Alaskan reserves tax | — | — | 115.0 | 140.0 | 255.0 |
| Trans-U.S. pipeline | — | — | 75.0 | 50.0(d) | 125.0 |
| Total | $618.0 | $850.0 | $1,732.0 | $877.8 | $3,459.8 |
| Indicated financing needs | $521.7 | $742.3 | $1,519.0 | $367.8 | $2,629.1 |

(a) *1977 figure includes $88.9 million of producing profit (58.8 million barrels @ $1.51/bbl), $44.5 million of pipeline profit (36.8 million barrels @ $1.21/bbl) based on pipeline throughput of 600,000 b/d from July 1 through December 31, and 1.2 million b/d thereafter. Also included are estimated TAPS and field development ITC benefits of $117.5 million.*

(b) *Assumes realignment of expenditures with unit interests by year-end 1976.*

(c) *Excludes capital projects to be financed off-balance sheet including $720 million for tankers and $200 million for the estimated capitalized value of lease obligations in connection with El Paso natural gas pipeline facilities to be used for TRUSS.*

(d) *Assumes that 50% of TRUSS pipeline system will be sold to other companies at year-end 1977.*

Clearly, 1975-1976 is the period of peak outside funding needs for the company. In 1977 initial cash flow from startup of the pipeline at 600,000 b/d along with a drop off in TAPS expenditures should result in sharply reduced external financing needs. The importance of the $117.5 million of investment tax credit as a source of earnings in the 1977 projection is particularly noteworthy. Because of these benefits, actual North Slope earnings of 600,000 b/d will be significantly higher than might be suggested by simply applying an estimate for fully taxed margins on the oil at that level of throughput. Non-cash charges including pipeline depreciation ($16.8 million), capitalized interest amortization ($4.5 million), and deferred taxes ($42.6 million) are also quite meaningful factors assisting the 1977 funding picture. Based on all of these considerations, and *assuming that similar ice problems do not develop in 1976,* permitting an on-time startup at the *phase one* volume, it appears that the financial consequences of this year's barge difficulties can be handled within Sohio's current funding plan.

As discussed in some detail in our May report, Sohio's financing of the pipeline should be viewed separately from Prudhoe Bay development and other expenditure needs. To meet its mammoth pipeline requirements of the next few years, Sohio management has already lined up several substantial sources of funds including (1) a $600 million line of bank credit (of which $125 million was drawn down as of September 5, 1975), (2) two public debt issues totaling about $339 million (8 5/8% Notes due 1983 and 9 3/4% Debentures due 1999), and (3) a $1.75 billion private placement of BP/Sohio pipeline debt of which $1,186.5 million is net to Sohio. In all, slightly more than $2.0 billion of pipeline debt has been arranged if it is assumed that bank lines will be completely drawn down and converted to an intermediate term loan, as is Sohio's option. At an assumed 85% debt ratio for total pipeline expenditures, including capitalized interest, additional pipeline debt funding requirements would be on the order of $325 million if the system cost assumption used here (i.e. 10% further cost escalation) remains intact.

Beyond TAPS debt needs, the remaining capital obligations of the parent company consist of (1) the unfunded portion of the 15% equity in the pipeline, (estimated at $280 million through 1977*), (2) the $749 million of field development work, (3) other capital expenditures of $331 million, (4) $255 million of Alaskan reserves tax obligations, and (5) $125 million toward a trans-U.S. pipeline system. Available to partly meet these $1,740 million of other requirements, Sohio has $275 million of unused bank lines (parent's $300 million facility) and an estimated $852 million of available cash flow. This leaves an unfunded balance of approximately $888 million.

Viewed in the foregoing context, management's decision to proceed with an equity offering is hardly surprising, and it seems fair to conclude that the current two million share sale may not be the last. In fact, this analyst's working assumption continues to be the ultimate sale of up to six million new shares prior to commencement of North Slope production . At an average price of $75 per share, this would cover slightly more than 50% of the remaining external funding needs already outlined, with the balance currently expected to be met by (1) additional parent company debt, (2) inter-company adjustments in field development

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**This assumes that the parent company's advances to Sohio Pipe Line which total approximately $110 million, are fully converted to equity.*

costs, (3) advance crude sales, and (4) disposition of other corporate assets. The latter two options were both discussed in our earlier report and are available to management under the soon-to-be finalized covenants of the private placement. The next table recapitulates these details of Sohio's financing needs and arrangements to date.

Standard Oil (Ohio)

**Financing Requirements & Arrangements**
(In millions)

| | | | |
|---|---|---|---|
| TAPS expenditures | $2,428 | Arranged but unused credit (a) | $1,355 |
| Capitalized interest | 455 | | |
| Total TAPS | $2,883 | Remaining TAPS debt to be arranged | |
| Less expenditures through mid-1975 | 900 | ($1,680 less $1,355) | 325 |
| Remaining expenditures | $1,983 | | |
| TAPS debt financing to 6/30/75 | 923 | Total additional debt | $1,680 |
| Remaining expenditures to be financed ($2,883 less $923) | 1,960 | | |
| Equity needed ($2,883 x 15% less $152) (b) | 280 | Remaining parent pipeline equity requirement | 280 |
| Debt capacity ($2,883 x 859, less $771)(c) | 1,680<br>1,680 | | |
| Total to be financed | $1,960 | Total | $1,960 |

**Other Activities**

| | |
|---|---|
| Total uses (ex TAPS) less total sources ($1,460 less $831) | $ 629 |
| Non-debt sources (d) | 170 |
| Debt requirements | 459 |
| **Combined Financing Needs:** | |
| Debt | $2,139 |
| Non debt | 450 |
| Total | $2,598 |

*(a) $1,186.5 million private placement plus $168.5 million of Sohio Pipe Line's bank credit not backing up $431.5 million of commercial paper.*

*(b) Includes $42 million of existing equity and assumed conversion of $110 million of parent company advances.*

*(c) TAPS debt financing through mid-1975 is $771 million.*

*(d) $450 million of assumed proceeds from equity sale less $280 million contributed to pipeline equity.*

Based on the financing expectations just outlined, it appears that Sohio's long-term debt will nearly triple from the mid-1975 level as shown in the following projection of the company's balance sheet position for year-end 1977.

(See table on following page)

**Standard Oil (Ohio)**

Partial Balance Sheet Data
(In millions)

| | June 30, 1975<br>(Unaudited) | December 31, 1977<br>(Estimated) |
|---|---|---|
| Long-term debt | $1,180 | $3,319(a) |
| % of total capitalization | 48.0% | 64.9% |
| Preferred stock | 11 | 11 |
| % of total capitalization | 0.4% | 0.2% |
| Special stock (BP) | 25 | 25 |
| % of total capitalization | 1.0% | 0.5% |
| Common shareholders' equity | 1,247 | 1,758 |
| % of total capitalization | 50.6% | 34.4% |
| Total capitalization | $2,463 | $5,113 |

Totals may not add due to rounding.

*(a) Does not include $720 million of tanker construction/charter obligations and lease commitments of $200 million for the use of the El Paso natural gas facilities.*

If our projections prove reasonably accurate, footnote (a) above could become significant since Sohio management has agreed to a covenant in the TAPS private placement which establishes a $3,750 million limitation on permitted indebtedness for financing its share of TAPS construction costs, production facilities, and tankers. If the company's non-North Slope related debt is backed out of the estimated 1977 figure, it appears that Sohio could be approaching this ceiling by late 1977. However, one must also note that management has considerable flexibility here in that it is possible to reduce its tanker obligations by arranging to sell oil at Valdez, which in effect shifts tanker commitments to other offtakers. The explicit provision allowing for this possibility suggests that it is an option that will receive active management consideration if further cost escalation or an earnings shortfall from these projections causes Sohio to more closely approach the debt ceiling. In all, further cost escalation for TAPS and field development, along with the Alaskan reserves tax, have certainly made Sohio's financing task no less formidable than at the time of our last *Basic Report*; however, Sohio's arrangements to date – including an all but concluded private placement financing – provide good evidence of the continuing manageability of the financial situation.

## Financial Position Review – Atlantic Richfield Company

Based on our revised cost parameters for pipeline construction and Prudhoe Bay field development, the following table summarizes Arco's past and projected cost position.

(See table on following page)

### Atlantic Richfield

### Estimated North Slope Pipeline and Development Costs
(In millions)

| | Expended Through 1974 | Approximate Remaining Obligation | Total |
|---|---|---|---|
| TAPS: | | | |
| To 1.2 million b/d | $285 | $1,188 (a) | $1,473(b) |
| To 2.0 million b/d (c) | – | 196 | 196(d) |
| Capitalized pipeline interest through mid-1977 (c) | 25 | 250 | 275 |
| TAPS total | $310 | $1,634 | $1,944 |
| Field development | 79 | 341 | 420(f) |
| Total North Slope | $389 | $1,975 | $2,364 |

(a) *Includes $215 million spent through May 31, 1975.*

(b) *21% of Alyeska's latest cost estimate ($6,375 million) escalated by 10% to $7,012.5 million.*

(c) *Not including additional costs associated with a future realignment of TAPS ownership interests.*

(d) *21% of Alyeska's latest cost estimate ($850 million) escalated by 10% to $935 million.*

(f) *21% of an estimated $2,375 million of total field development costs necessary to reach producibility of 1.5 million b/d.*

Out of total North Slope expenditures of $2,364 million outlined above, $389 million, or 16%, had been expended through 1974. Based on a number of unspecified assumptions, Arco management's own estimate of the cost to develop its share of the proven oil and gas reserves in the main Prudhoe Bay field through 1990 approximates $2.5 billion. As discussed in the Sohio Financial Position section, field development expenditures do not take into account the possibility that the time value of early expenditures made by Sohio for the western operating area will be recognized under field unitization.

Including an incremental financing requirement necessitated by the passage of the Alaskan reserves tax and other appropriate modifications to the writer's earlier assumptions, the next table updates Arco's sources and uses of funds and indicated financing needs over the 1975-1977 period.

(See table on following page)

## Atlantic Richfield

### Projected Financing Needs 1975-1977
(In millions)

| | 1975 | 1976 | 1977 | Cumulative Total |
|---|---|---|---|---|
| Sources: | | | | |
| Net income (a) | $ 320 | $ 383 | $ 599 | $1,302 |
| DD&A | 375 | 425 | 494 | 1,294 |
| Dry hole drilling costs | 90 | 90 | 90 | 270 |
| Deferred Federal income taxes | 50 | 50 | 80 | 180 |
| Cash flow from operations | $ 835 | $ 948 | $1,263 | $3,046 |
| BP note receivable | 58 | 58 | — | 116 |
| Sale of assets (b) | 16 | — | — | 16 |
| Issues of common stock | — | — | — | — |
| Long-term borrowings (b) | 500 | — | — | 500 |
| Total sources | $1,409 | $1,006 | $1,263 | $3,678 |
| Uses: | | | | |
| TAPS outlays | $ 512 | $ 544 | $ 188 | $1,244 |
| Capitalized interest | 61 | 110 | 79 | 250 |
| North Slope development | 200 | 144 | 76 | 420 |
| Alaskan reserves tax | — | 55 | 65 | 120 |
| Capital expenditures (ex. No.Slope) (c)(d) | 900 | 900 | 1,000 | 2,800 |
| Cash dividends | 157 | 157 | 157 | 471 |
| Debt repayments | 48(b) | 117 | 24 | 189 |
| Total uses | $1,878 | $2,027 | $1,589 | $5,494 |
| Indicated financing needs | $ 469 | $1,021 | $ 326 | $1,816 |

*(a) 1977 figure includes $36 million of producing profit (23.2 million barrels @ $1.54/bbl) and $28 million of pipeline profit (23.2 million barrels @ $1.21/bbl) based on pipeline throughput of 600,000 b/d from July 1 through year-end. Also included are estimated TAPS and field development ITC benefits of $113.8 million.*

*(b) Through June 30, 1975.*

*(c) Excludes capital projects financed off-balance sheet estimated at $300 million, $300 million, and $150 million in 1975, 1976, and 1977, respectively.*

*(d) Includes dry hole drilling costs shown above.*

As a result of an improved level of 1977 cash flow associated with the initial buildup of Prudhoe Bay production and an assumed lower level of non-Alaskan capital spending, Arco's indicated 1975-1977 funds shortfall of $1,816 million compares quite favorably with the figure of $2,140 million contained in our May report, despite an intervening increase in both pipeline system and field development costs and the passage of the Alaskan reserves tax. Even with the assumption of restricted output of 600,000 b/d from July 1, 1977 through year-end, the writer estimates Arco will earn $178 million ($3.08 per share) from the North Slope for 1977. Also, depreciation and amortization charges and deferred Federal income taxes (calculated on the basis of a normalized pipeline throughput rate of 1.2 million b/d) are estimated to contribute $19 million and $21 million, respectively, to internally generated funds during the first six months of project operation.

North Slope derived investment tax credit benefits obviously represent a non-recurring source of earnings; nevertheless, the assumed availability of these credits provide yet another source of funds to meet pre-startup financing needs and a potentially sizable benefit to reported earnings in the 1975-1977 period under progress payment rules newly enacted under the Tax Reduction Act of 1975 (see footnote on page 18 for discussion of this treatment). To illustrate the amounts involved for Arco, the writer estimates ITC benefits will total to $12 million (21¢ per share), $37 million (64¢ per share) and $114 million ($1.98 per share) for 1975, 1976, and 1977, respectively. In succeeding years, as operating earnings begin their impressive rise, the amount of ITC will drop precipitously.

Once again, in attempting to gain additional insight into management's possible financing strategy, it is useful to segregate the TAPS project from the remainder of Arco's corporate activities. Assuming a 90%/10% and 30%/70% debt/equity ratio for TAPS and other corporate projects, respectively, the following breakdown of financing requirements results.

**Financing Requirements & Arrangements**
**(In millions)**

| **TAPS Project** | | | **Other Activities** | |
|---|---|---|---|---|
| TAPS expenditures | $1,529 | | Total uses (ex. TAPS) less total sources (ex. TAPS borrowings) ($4,000 less $3,178) | $822 |
| Capitalized interest | 275 | | | |
| Total TAPS | $1,804 | | | |
| Less expenditures through 1974 | 310 | | | |
| Remaining expenditures | $1,494 | | Non-debt needed ($822 x 70%) | $575 |
| TAPS financing to date(a) | 865 | | | |
| Remaining expenditures to be financed($1,804 less $865) | $ 939 | | Debt capacity ($822 x 30%) | $247 |
| Equity needed ($1,804 x 10% less $75) | $ 105 | | | |
| Debt capacity ($1,804 x 90% less $790) | 834 | | | |
| Total to be financed | $ 939 | | Total to be financed | $822 |
| Combined financing needs | | $1,761 | | |
| Debt | | $1,081 | | |
| Non-debt | | $ 680 | | |

*(a) Financing to date has included $200 million of 8.7% Guaranteed Notes of 1981, $250 million of 8% Guaranteed Notes of 1982; $250 million of 8 3/8% Guaranteed Notes of 1983; and $90 million of other intermediate and long-term debt. To cover short-term borrowing requirements, ARCO Pipeline also has available $250 million of the parent company's unused $532 million credit lines and a $150 million four-year backup credit from a group of European and Canadian banks. Also included in financing to date is $75 million of equity which is arbitrarily assumed to be available from ARCO Pipeline Company's existing shareholders' equity.*

Arco has available a number of options to cover its $680 million of imputed non-debt financing requirements. These include: (1) property sales, (2) a drawdown of working capital (3) sale of common stock, (4) advance payments by natural gas transmission companies, (5) advance sales of crude and/or natural gas, and (6) a further cutback in the level of non-Alaskan capital expenditures. Funds from property sales could be potentially significant if the company can successfully divest itself of the East Chicago refinery and the bulk of its Midcontinent marketing properties. Recent agreements have been concluded with three natural gas transmission companies providing for interest-free advances to Arco totaling $720 million to finance the costs of exploration, development, and production of natural gas from the Prudhoe Bay field. Assuming necessary regulatory approvals are forthcoming, a sizable portion of these monies could be forthcoming by year-end 1977. Even with the likelihood of expenditures associated with the company's participation in the construction and/or lease of a trans-U.S. pipeline to move surplus North Slope crude to midcontinent markets prior to 1978, Arco continues to enjoy a comfortable financing burden.

Based on the financing pattern outlined above, including the sale of one million common shares at $100 per share, the next table shows balance sheet data for 1974 and a projection for year-end 1977.

Atlantic Richfield

Partial Balance Sheet Data
(In millions)

| | As of December 31 | |
|---|---|---|
| | 1974 | 1977 |
| Long-term debt | $1,219 | $2,800 |
| % total capital. | 26%(b) | 39% |
| Minority interest | $ 68 | -- |
| % total capital. | 1% | -- |
| Preferred stock | $ 49 | $ 49 |
| % total capital. | 1% | 1% |
| Shareholders' equity | $3,406 | $4,337 |
| % total capital. | 72% | 60% |
| Total capitalization | $4,742 | $7,186 |
| Common shrs. outstdg.(c) | 56.7 | 57.7 |
| Book value per share | $60.07 | $75.16 |

*(a) Including $500 million of long-term debt issued to date in 1975.*

*(b) Including the present value of noncapitalized financing leases ($343 million), the ratio becomes 31%.*

*(c) Including common share equivalents (representing an additional 10,615,249 shares as of March 31, 1975).*

As indicated in the right-hand column of the table, Arco's December 31, 1977 long-term debt comprises 39% of total capitalization – a position nearly identical to that developed in our May report. Unlike Sohio, where the parent company itself faces a significant financing burden which dictates some reliance on the sale of equity, Arco's assumed use of common stock rests mainly on cost of capital considerations.

## Longer Term Earnings

### Longer Term Earnings – The Standard Oil Company (Ohio)

The foregoing revisions in North Slope pipeline and production economics point to the need to also adjust our earlier projections for Sohio's earnings power by 1981. Additional specific assumptions underlying these revisions include:

(1) Sohio Pipe Line Company's interest in TAPS will remain at 33.34%.

(2) BP-Sohio's estimated 53.3% ownership in the main Prudhoe unit will provide Sohio with a similar percentage of actual production of 1.2 million b/d.

(3) When output from the main unit reaches its estimated 1.5 million b/d potential, BP-Sohio's share will approximate 800,000 b/d (still 53.3% of the total); but under the terms of the merger agreement Sohio's interest before royalty will be 714,000 b/d. (The merger agreement is summarized in Appendix I of our May *Basic Report*.)

(4) BP-Sohio's combined share of an additional 500,000 b/d of production will be 125,000 b/d or one quarter of the increment of which 31,250 b/d or 25% would accrue to Sohio under the BP merger agreement.

(5) In view of the enormous political, procedural and economic difficulties involved in completing the natural gas transmission system to tap Prudhoe Bay gas, this earnings source is likely to start up sometime after 1981.

(See table on following page)

**Standard Oil (Ohio)**

**Potential 1981 Earnings**
(In millions)

| | | | |
|---|---|---|---|
| Crude Price (Signal Hill 27° ) | $8.00 | $10.00 | $12.00 |
| Production profit per barrel | $1.20-$1.39 | $1.92-$2.18 | $2.67-$2.92 |
| North Slope production: | | | |
| Sadlerochit pool | $362.8 | $566.4 | $752.5 |
| Other pools (Lisburne/Kuparuk) | 13.7 | 21.9 | 30.3 |
| Total production profit | $376.5 | $588.3 | $782.8 |
| 33.34% of equity in TAPS | 177.9 | 177.9 | 177.9 |
| Earnings from existing operations | 150.0 | 150.0 | 150.0 |
| Cost of added interest & deferred interest amortization | (33.0) | ( 33.0) | (33.0) |
| Total net earnings | $671.4 | $883.2 | $1,077.7 |
| Earnings per share | $10.31 | $13.56 | $16.55 |

The earnings estimated here for the $10.00 and $12.00 per barrel crude prices correspond quite closely to those we had previously projected for $8.00 and $10.00 prevailing realizations under our earlier assumptions involving lower system costs and about $55 million in 1981 natural gas profits. This illustrates how important the crude price scenario for 1980 and beyond has become for this highly capital intensive project. To date, limited prospects for other U.S. producing provinces and the continued viability of OPEC have provided good support for the view that lower 48 U.S. realizations will be more than sufficient to keep Valdez netbacks attractive. On balance, a sanguine view of crude price prospects is still appropriate, with even a bias toward the upper end of the range used here. However, the dynamics of the situation as outlined in the discussions on the State of Alaska and overall pipeline/wellhead economics dictate ongoing analysis over a range of possible prices and close monitorship of such evolving political elements, especially given the state's role as royalty owner likely to take its crude *in-kind.*

### Longer Term Earnings – Atlantic Richfield Company

The incorporation of the revised pipeline and Prudhoe Bay field profitability parameters developed above, with the following specific set of assumptions for Arco, leads to an outline of possible 1981 earnings power for this large prospective producer of North Slope oil and gas.

Assumptions:

(1) ARCO Pipeline Company's ultimate interest in TAPS will approach 24%.

(2) Atlantic Richfield will have an approximate 21% interest in the main Prudhoe Bay reservoir (Sadlerochit) and as much as 33% of the aditional 500,000 b/d of North Slope-production, provided it comes from currently leased acreage (i.e., not the Beaufort Sea), that may be needed to attain peak pipeline throughput of 2 million b/d in the 1980's.

(3) Existing operations will earn $9 per share in 1981, an 8% growth rate from 1975's base, mainly reflecting improved oil and gas realizations superimposed on a declining rate of output, and initial *modest* returns accompanying the company's aggressive petrochemical expansion program. To the extent that a higher crude price assumption has been used, a corresponding adjustment has been made to the expected earnings contribution from ARCO Chemical Company.

(4) In view of the overwhelming political, procedural, and economic difficulties involved in completing a natural gas transmission system to tap Prudhoe Bay gas supplies, earnings from this source are unlikely in a 1981 time frame and have consequently been excluded from the following analysis.

Atlantic Richfield

Potential 1981 Earnings
(In millions)

| Crude price (Signal Hill 27°) | $8.00 | $10.00 | $12.00 |
|---|---|---|---|
| Production profit per barrel | $1.20-$1.39 | $1.93-$2.18 | $2.66-$2.91 |
| North Slope Production: | | | |
| Sadlerochit pool | $159.2 | $250.6 | $334.6 |
| Other pools (Lisburne / Kuparuk) | 72.3 | 116.2 | 160.2 |
| Total production profit | $231.5 | $366.8 | $494.8 |
| 24% equity in TAPS | 127.5 | 127.5 | 127.5 |
| Earnings from existing operations | 518.8 | 518.8 | 518.8 |
| Total net earnings | $877.8 | $1,013.1 | $1,141.1 |
| Earnings per share | $15.21 | $17.56 | $19.78 |

Earnings figures derived for the $10 and $12 per barrel cases conform quite closely with the results obtained using a price range of $8-$10 per barrel and natural gas earnings of $1.08 per share in our May report. This demonstrates the importance that highly-unpredictable future trends in crude oil prices assume in any overall assessment of the economics of the North Slope project. For example, as is evident in the table above, the difference between the $10 and $12 per barrel price scenarios gives rise to a $128 million ($2.22 per share) variance in total North Slope crude oil production profit. To date, the need for a high price dictated by the marginal economics of new U.S. exploration* and the continued viability of OPEC have provided good support for our view that the likely prevailing level of lower-48 crude oil prices will be more than adequate to keep Valdez netbacks attractive.

H. C. WAINWRIGHT & CO.
Paul R. Leibman
Thomas A. Petrie

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**A recent study by an independent petroleum consultant concluded that for a producer to earn a 15% DCF return on new oil investments after taxes in 1974, a $12.73 per barrel gross oil price at the wellhead would be required.*

Price Waterhouse & Co.

601 WEST FIFTH AVENUE, ANCHORAGE, ALASKA 99501 · 907-279-1424

Council file

January 17, 1975

Mr. John M. Elliott
Executive Director
Legislative Affairs Agency
State of Alaska
Pouch Y - State Capitol
Juneau, Alaska 99801

Dear Mr. Elliott:

Thank you for your letter of January 9, 1975 inviting our firm to propose on the consulting engagement being directed by your Legislative Council to study the Alaska corporate income tax structure. As you correctly noted in your letter, our firm, in particular our Anchorage office, has closely followed the development of this study since its first public announcement. After reviewing your specific outline of matters to be covered in the study, however, we have had to reconsider the desirability of becoming involved with your study at its present stage. Our decision, regretably, is that the immediate study objectives, particularly those outlined as points 1, 2, 3 and 4 in your letter, (copy enclosed) do not require the specific capabilities and expertise that our firm offers. Therefore, for reasons which I will briefly describe, we respectfully decline your invitation to consider our services as consultants for this stage of the Alaska corporate income tax study. I assure you of our continued interest in your Councils efforts and our willingness to assist in any facet of the undertaking where our firm's experience and expertise may be particularly beneficial.

Since we have expressed a continued interest in the development of this study over a period of several months, I would like to briefly describe the considerations that led to the decision that our participation as primary consultants at this stage of the corporate income tax study would not provide the most effective means of accomplishing the Council's outlined study objectives. Objectives 1, 2 and 3 outlined in your letter are in the nature of a statistical abstract of tax information which can only be gleaned from confidential tax returns. This information will almost certainly have to be compiled within and by the Department of Revenue. Even if such information should be made available for review by your consultant, we feel that our firm's continuing association and ethical responsibilities to our Alaska corporate and business clients, and the competitive ethics within our profession, would preclude our involvement with any such confidential records which might pertain to either our clients or our clients' competitors.

Study objective 5 presents practical as well as theoretical tax considerations where the experience and expertise of Price Waterhouse & Co. could prove very beneficial to your study group. Consideration of the questions outlined in objective 5, however, depend entirely on the development of reliable and meaningful statistical information under objectives 1, 2 and 3.

The additional items for consideration which you have listed in your letter seem to address several narrow areas which the Council may feel represent special interest "loopholes" or merely untapped revenue sources within the corporate income tax framework. In either case, we feel that our firm's consideration of such questions would place us in an untenable conflict of interest with clients that might be affected by legislative changes resulting from our recommendations. A conflict of interest situation would not be acceptable, of course, to either the Council, our firm or our clients.

* * * * * * * *

We would like to once again express our thanks for the time you have taken to answer questions regarding your Council's study and your extension of the opportunity to propose. We are vitally interested in Alaska and the Alaskan community and we look for an opportunity to express our interest through service to the community and to the State. As a final item of interest, I am enclosing a copy of the study by the Governor's Commission on Tax Reform for the State of Connecticut. I obtained this copy from Mr. Carl Ward, a partner in our Hartford office and a member of the Commission. Perhaps this example of what another state has done might provide your Council with additional ideas for consideration during the course of your study.

Again, we continue to be interested in the progress of your study and we express our appreciation for your consideration.

Yours very truly,

Craig Duncan

C. P. Duncan

Price Waterhouse & Co.

Enclosures-
As stated

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99801

January 9, 1975

Mr. Craig Duncan
Price Waterhouse & Company
601 West Fifth Avenue
Anchorage, Alaska 99501

Dear Mr. Duncan:

I am writing at this time in regard to the resolution passed during the 1974 legislative session requesting the Legislative Council to conduct a study of corporate income taxes in Alaska. Although the resolution called for the study to be presented to the legislature by the tenth day of the 1975 session, circumstances prevented the study from commencing until this time. Now, however, the Council has made a firm determination to proceed with the study, realizing that the time limits set forth in the resolution cannot be met. The Council is desirous of getting someone on board immediately, however, to commence work and to complete the study at the earliest possible time feasible. Price Waterhouse has expressed an interest in being considered when persons or firms were being considered to conduct the study. This letter is a formal invitation for Price Waterhouse to make a specific proposal to the Council should that be your wish.

Matters which the Council desires to be covered in the study are the following:

1. An analysis of corporate activity in Alaska by industry, size of firm and location;

2. What is the combined tax burden on various industries and firms of various sizes of the income, business license, property, severance and other state taxes;

3. To what extent are multi-state or multi-national corporations involved in Alaska industry - what is the amount of income apportioned to Alaska for multi-state or multinational corporations doing business in Alaska;

4. How good is corporate compliance with the state tax laws, the multi-state compact, and the foreign tax treaty; and

5. What would be the effect on State revenues and corporate tax burdens of deleting or otherwise changing special provisions (such as the depletion allowances, foreign tax credits, etc.) or changing the tax rates or tax structure. Would specific changes cause any significant change in incentives toward corporate activity or affect long range growth in Alaska?

Other items discussed with a view for inclusion, some of which would obviously be inherent in an examination of the matters listed above, would be:

1. Are particular industries or other classes of firms posing particular problems;
2. What specific reporting methods enable the avoidance of Alaska taxes and how much is involved;
3. What enforcement efforts are there and are they adequate. What is the Federal role and the multi-state role;
4. What potential revenues stand to be collected from various industries and various sizes of firms;
5. What special provisions relating to the taxation of corporations in general (ADR, DISC, etc.) and specific industries in particular (depletion allowances, foreign tax credits, etc.) currently give rise to significant "tax expenditures" by the state or will in the future;
6. How does Alaska's situation compare with other states, and
7. What, if any, legislation is needed?

If there are other pertinent areas that Price Waterhouse might feel should be included, you are invited to include same in any proposal forwarded to the Council.

Because of the fact that the present Legislative Council will go out of existence once the 1975 legislative session convenes, time is a critical factor as the Council is desirous of choosing the firm or person to conduct the study before that time. The next (and most likely the last) meeting of the Council will be held in Juneau on Friday, January 17th. If at all possible, a written proposal should be before the Council at that meeting. You are cordially invited also to have a representative make an oral presentation before the Council if you so desire. Estimated costs, approaches to meeting the Council's requirements, and some sort of preliminary timetable for the completion of the study should be included in any proposal you might desire to make.

If you have any questions concerning this matter, please feel free to give me a call at any time.

For your information, the meeting on the 17th will be held in this office (Room 109, State Capitol Building) commencing at 10:00 a.m. It will be possible, however, for me to set this matter for the afternoon if you desire to have someone present. That way, he could come to Juneau on the morning flight rather than having to arrive a day before the meeting.

Finally, a copy of the resolution, as passed by the legislature, is enclosed for your information and perusal.

Sincerely,

John M. Elliott

JOHN M. ELLIOTT
Executive Director

JME:hg
Enclosure: HCR No. 78, 1974

cc: Rep. Richard L. McVeigh
Rep. Tom Fink
Sen. Robert H. Ziegler, Sr.

Research Department

# Wertheim

# Industry Commentary

Joseph S. Clark, Jr.

January 16, 1976

## ALASKAN TAX LEGISLATION

We continue to view the shares of Arco (88) and Sohio (70) as attractive long-term investments, although if Alaskan State Senator Huber's proposed tax legislation passes in its entirety, the stocks could demonstrate further nearer-term weakness as questions of still higher potential taxes would continue. In analyzing the investment issues involved, it seems appropriate to deal first with the financial impact of the proposed taxes on the companies' estimated 1978 earnings, and second, to analyze the possibility of further adverse tax legislation by Alaska at some future date. It is clear, for instance, that investors have not forgotten the recent history of rising oil company taxation worldwide, although investors sporadically seem to forget that Alaska is a state. While, of course, one can only speculate at the present time, we believe that while the Alaskan legislature will probably raise taxes somewhat and may raise taxes again in the future somewhat, tax levels will not be radically changed, and that over the long run, the profitability of Alaskan oil will equal or exceed the $2.00 per barrel which we have assumed as a base level to generate 1978 profits of $11.00 per share for Sohio and $13.15 per share for Arco. Consequently, we believe that once the Alaskan tax issue is thoroughly discussed, it will be put to rest in a rational manner.

Our analysis is based on recent conversations with the oil companies involved, with Senator Huber and his staff, and with officials in the Alaskan Department of Revenue.

At this point in time, it is perhaps unnecessary to note that the Alaskan legislature will convene on January 19th to consider, among other legislation, a proposal by State Senator Huber to increase state taxes on Alaskan oil production. Senator Huber, a ~~liberal~~ Democrat but not an environmentalist, who is Chairman of the State Senate's Special Committee on Taxation ~~Ways & Means Committee and is running for reelection this year~~ Oil Revenue, has for several months been attempting to construct a method of increasing future state revenues via higher taxes on Prudhoe Bay production. Presently, the severance tax is based on a sliding scale relating to the production volume by well and should average 8% for the high output Prudhoe Bay wells. The state income tax, which, like the severance tax, is deductible for Federal income tax purposes, currently is set at 9.36%.

Recognizing that our Alyeska pipeline tariff estimates may be lower than those projected by others (see Sohio Investment Recommendation dated

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New York, New York 10005
Tel (212) 558-3300

March 24, 1975 for a complete discussion of our tariff assumptions), the following table summarizes our estimates of Prudhoe Bay profitability per barrel based on the current Alaskan tax structure. We have used two price assumptions for delivery in California, $9.00 and $12.00 per barrel:

| | Per Barrel | | | |
|---|---|---|---|---|
| California Price | | $9.00 | | $12.00 |
| Tanker Cost | | 0.50 | | 0.50 |
| Valdez Value | | $8.50 | | $11.50 |
| Pipeline Tariff | | 2.60 | | 2.60 |
| P. B. Wellhead Price | | $5.90 | | $ 8.90 |
| Operating Costs | $0.45 | | $0.45 | |
| Severance Tax (8%) | 0.47 | | 0.71 | |
| Royalty (12.5%) | 0.74 | | 1.11 | |
| State Tax (9.36%) | 0.40 | | 0.62 | |
| Federal Tax (48%) | 1.84 | | 2.88 | |
| | | 3.90 | | 5.77 |
| Profit Per Barrel | | $2.00 | | $ 3.13 |

Senator Huber's tax proposals have not yet been reduced to legislative form and therefore there are provisions that must be subject to some conjecture at the present time. Basically, as they relate to Prudhoe Bay production, they consist of three parts, an increase in the average severance tax from 8% to 13.5%, a clearer definition of the present 9.36% state income tax insofar as the oil industry is concerned (Huber feels that for one reason or another the full tax rate has not been paid by the oil companies on Cook Inlet production), and a so-called excess value or "windfall" income tax levied on unit profits above a certain level. Senator Huber's thinking has not yet been precisely defined as to the cut-off point between the 9.36% tax and the higher windfall tax, nor has the proposed windfall rate been defined. However, his current thinking on the latter item ranges from 25%-50%, levels that may well be unacceptable to business interests in the House. The proposed cut-off point seems to be based on profits derived from delivered California prices above $7-$9 per barrel. For example, if the cut-off price in California was $8.00 per barrel and the oil companies' actual realization was $12 per barrel, a state tax of, say, 37 1/2% would be applied to the $4 per barrel difference.

Using the preceding rough assumptions, $12 oil in California might be taxed by Alaska as follows:

| | | Cut-Off Price | | | "Excess" Price | | Total |
|---|---|---|---|---|---|---|---|
| | | | | Per Barrel | | | |
| California Price | | $8.00 | | | $4.00 | | $12.00 |
| Tanker Cost | | 0.50 | | | - | | 0.50 |
| Valdez Value | | $7.50 | | | $4.00 | | $11.50 |
| Pipeline Tariff | | 2.60 | | | - | | 2.60 |
| P. B. Wellhead Price | | $4.90 | | | $4.00 | | $ 8.90 |
| Operating Costs | $0.45 | | | $ - | | $0.45 | |
| Severance Tax (13.5%) | 0.66 | | | 0.54 | | 1.20 | |
| Royalty (12.5%) | 0.61 | | | 0.50 | | 1.11 | |
| State Tax (9.36%) | 0.30 | | (37.5%) | 1.11 | | 1.41 | |
| Federal Tax (48%) | 1.38 | | | 0.89 | | 2.28 | |
| | | 3.40 | | | 3.04 | | 6.44 |
| Profit Per Barrel | | $1.50 | | | $0.96 | | $ 2.46 |

The arithmetic of $9 oil in California would be as follows:

| | | Cut-Off Price | | | "Excess" Price | | Total |
|---|---|---|---|---|---|---|---|
| | | | | Per Barrel | | | |
| California Price | | $8.00 | | | $1.00 | | $9.00 |
| Tanker Cost | | 0.50 | | | - | | 0.50 |
| Valdez Value | | $7.50 | | | $1.00 | | $8.50 |
| Pipeline Tariff | | 2.60 | | | - | | 2.60 |
| P. B. Wellhead Price | | $4.90 | | | $1.00 | | $5.90 |
| Operating Costs | $0.45 | | | $ - | | $0.45 | |
| Severance Tax (13.5%) | 0.66 | | | 0.14 | | 0.80 | |
| Royalty (12.5%) | 0.61 | | | 0.13 | | 0.74 | |
| State Tax (9.36%) | 0.30 | | (37.5%) | 0.27 | | 0.57 | |
| Federal Tax (48%) | 1.38 | | | 0.22 | | 1.60 | |
| | | 3.40 | | | 0.76 | | 4.16 |
| Profit Per Barrel | | $1.50 | | | $0.24 | | $1.74 |

Our present thinking is that the two preceding tables, which obviously are based on only one of many possible versions of Senator Huber's proposals to be modified by the legislature, represent worst case examples in terms of Alaskan taxation. We will outline our thinking on this subject later in this report.

The following table summarizes our per barrel net profit calculations:

| | $9 Cal. Oil | $12 Cal. Oil |
|---|---|---|
| | Per Barrel | |
| Existing State Taxes | $2.00 | $3.13 |
| Possible New State Taxes | 1.74 | 2.46 |

The preceding Prudhoe Bay net profit estimates translate into the following earnings projections for Arco and Sohio[1]:

| | Est. 1978 EPS Present State Taxes | | Est. 1978 EPS Possible New Taxes | | % Decrease | |
|---|---|---|---|---|---|---|
| | $9 Oil | $12 Oil | $9 Oil | $12 Oil | | |
| Arco | $13.15 | $14.90 | $12.75 | $13.85 | (3) | (8) |
| Sohio | 11.00 | 15.20 | 9.80 | 12.60 | (12) | (17) |

As noted earlier, the question of increased Alaskan taxation clearly involves more complex investment issues than those outlined in the preceding mechanical earnings computations. Short term, the investor must weigh the market's reaction to either positive or negative oil industry developments during the soon-to-be-convened Alaskan legislative session. Longer term, if taxes are raised this session, he must consider the logic for and against further increases at some later date. Critical in the investor's appraisal is his judgment as to what level of profitability is being discounted in the marketplace at the present time.

In sifting the available evidence, it is difficult to measure the Alaskan legislature's longer-range appetite for tax revenues from the oil industry. The current mood of the Alaskan legislature is difficult to assess. There are strong currents of environmentalist opinion favoring a slower-paced development of the state's resources. On the other hand, there are elements that believe industry should be given attractive incentives in natural resource development to reduce unemployment and to provide a broad industry base. Several non-oil company government observers in Juneau believe that taxes will go up this session, but that the House (the source of financial legislation) will balk at legislation as radical as Senator Huber seems ready to introduce. The Senator himself acknowledges that since each of his three tax proposals must be introduced as a separate bill to stand on its individual merits, rather than as a single package, his chances of success are diminished.

Unfortunately, the lower-48 oil producing states' oil tax structures, which do not differ materially from Alaska's present tax levels, provide little in the way of historical guidance. In contrast to Alaska, local oil taxation policies in these states have been and continue to be, influenced by strongly-entrenched independent oil and gas political interests. Similarly, it is difficult to find legal precedents other than Federal intervention that would prevent

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[1] For background on these earnings estimates, see Investment Recommendations on Arco and Sohio dated 5/19/75 and 3/24/75, respectively, and subsequent Follow-Up Reports.

the state from raising taxes well above current levels, unless the oil companies could claim that such taxes were confiscatory or discriminatory in nature.

While we do not consider our impression of Senator Huber via long-distance telephone as particularly definitive, we got the impression of a realistic, practical man with Alaska's best interest at heart. He made two observations that seem pertinent. First, when asked whether or not he believed that tax increases in the coming session would be a prelude to further hikes in the future, he replied that his proposals were the basis for a "stable" state taxation plan that would be fair for the petroleum and other extractive industries. Second, he indicated that he was extremely conscious of the Federal government's attitude toward Alaska's taxation policies, since each $1.00 increase in state taxes diminished Federal revenues by $.48. He noted that Federal grants would continue to be a significant although diminishing contributor to the state's budget[2], and that Washington's attitudes toward state land use, Naval Petroleum Reserve 4, etc. were key factors in determining Alaska's long-term taxation policies.

In the above connection, it might be noted that the recently enacted Federal Energy Policy Act represented a compromise between those national legislators who felt that a high price is required ($11.28 or more) in order to stimulate domestic energy production, and those who believed that inflation and other domestic political problems require a lower cost of energy to consumers. Since Alaskan wellhead prices will be substantially below the U.S. lower-48 new oil price of at least $11.28, and since more future oil is expected to be found in Alaska than in other domestic areas (and at higher risk

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[2] It is interesting to analyze Alaska's state budget over the next several years. While the $900 million received in Prudhoe Bay bonuses has been long since spent, the fiscal (June 30) 1976 budget calls for a balance of outlays and receipts (including $212 million from the reserve tax) at $620 million. A similar balance at $700 million is projected for fiscal 1977, including the last reserve tax payment. For fiscal 1976 and 1977, a non-oil industry revenue base of $400 million and $410 million, respectively, is projected. While state outlays are certain to increase rapidly in subsequent years, we estimate that incremental state revenues in 1978 at 1.2 million B/D from Prudhoe Bay will approximate $1.3 billion, based on $12 oil in California and the existing Alaskan tax structure. Assuming all Senator Huber's tax proposals become law, the $1.3 billion production revenue figure would rise to $1.7 billion, thereby implying total state revenues of $1.7 billion and $2.1 billion, respectively, before taking into account repayment of the reserve tax from severance tax revenues.

and cost), it seems reasonable to question whether or not the Federal government will be anxious to see the State of Alaska reduce incentives significantly without, on the other hand, reducing the price to lower-48 consumers. It is this factor, aside from the question of fair play or other potential business interests in Alaska, which will ultimately limit the level of state taxation, and which distinguishes the Alaskan situation from that of a foreign country. It also is interesting to note that if Alaska were to pass a bill comparable to Senator Huber's proposed excess value tax, other states in the lower-48 which have additional revenue requirements or significant oil reserves, such as California, Texas, Oklahoma, Louisiana, etc.,might be expected to develop tax measures constructed in such a way as to place a windfall tax on certain profit levels. Production under certain levels and for independents could receive specific benefits, as is the case with depletion and stripper output today. For example, Marathon's profitable Yates production theoretically could be subject to windfall tax proposals which would not necessarily have the same impact on the smaller producer. Thus, the Federal government ultimately has to protect the basic integrity of its energy policy and its revenue sources, and consequently at some point would limit any extreme Alaskan tax measures.

Accordingly, in the last analysis, we believe that the Federal government will represent the ultimate controlling factor insofar as Alaskan taxation policies are concerned. In this connection, it is interesting to note that based on our unit profitability table on page 3, Alaska's total tax take amounts to $3.72 per barrel, some 63% above our estimated Federal revenue of only $2.28 per barrel. As noted above, it seems illogical to us that Washington will permit Alaska to undermine Federal revenues from a major natural resource, particularly in view of the enormous budget surpluses projected for Alaska by the end of the decade. Thus, the issue, if indeed it must be raised, may involve the historical question of Federal vs. states rights, an area where we believe the Federal government will prevail.

Regarding the current investment merits of Arco and Sohio, we believe that a total investment rate of return analysis, including dividend yield, is a helpful tool in such a determination. In the table that follows, we list for each company a series of terminal (1978) multiple alternatives ranging from 9 to 13 times based on a $2.50 Prudhoe Bay wellhead profit, a level we view as a reasonable expectation at the present time. At this level of profitability, we estimate that Arco will earn $13.90 per share and Sohio $12.75 per share in 1978.

Two-Year Compound Annual Return

| Assumed Multiple | 9x | 10x | 11x | 12x | 13x |
|---|---|---|---|---|---|
| Arco (90--1/15/76 Close) | | | | | |
| 1978 Objective Price | $125 | $139 | $153 | $167 | $181 |
| Annual Return (%) | 19.8 | 26.7 | 32.4 | 38.3 | 44.0 |
| Sohio (72--1/15/76 Close) | | | | | |
| 1978 Objective Price | $115 | $128 | $140 | $153 | $166 |
| Annual Return (%) | 28.4 | 34.5 | 41.1 | 47.9 | 52.0 |

In developing a case for a premium multiple for the shares of both companies -- the S&P 425 currently is priced at 10.9x our $10.00 estimate for 1976 profits and a group of domestic oils[3] at 8.6x projected results for the current year -- we once again stress the proprietary characteristics of both companies. In the case of Sohio, these include a pro-forma 1978 integration ratio of 150%, a reserve life index of over 20 years, cash flow over and above replacement requirements exceeding $400 million in 1978, and above all, a superb management record as corporate fiduciary in implementing the right investment decisions at the right time.

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[3]

| | Current Price | Est. 1976 Earnings P/S | P/E Ratio |
|---|---|---|---|
| Getty | $173 | $14.25 | 12.1x |
| Marathon | 43 | 5.80 | 7.4 |
| Phillips | 55 | 5.80 | 9.5 |
| Shell | 51 | 7.60 | 6.7 |
| Standard-Indiana | 43 | 5.90 | 7.3 |
| Average | | | 8.6x |

Note: Wertheim & Co., Inc. and/or persons associated with it have a position in the common shares and/or options in certain of these companies.

Research Department

**Wertheim**

**Industry Commentary**

Joseph S. Clark, Jr. January 27, 1976

## ALASKAN TAX LEGISLATION (II)

## NOTES ON JANUARY 20TH TRIP TO JUNEAU, ALASKA

At the present time, while uncertainty remains the most pervasive influence, we believe that the odds marginally favor the passage by the Alaskan Legislature in some form of Senator Huber's controversial excess profits tax bill (see Wertheim & Co., Inc. Industry Commentary Alaskan Oil Taxation -- 1/16/76). Two of his remaining bills (the fourth relates to pipeline taxes), dealing with a severance tax increase from 8% to an average 13.5% on high volume production such as Prudhoe Bay and the rationalization of the existing 9.36% state income tax, could eventually pass without strong opposition, although it is always possible that in the two months or so that probably will be required to pass legislation of this importance, compromises will occur in all tax areas. If the excess profits tax bill is passed, it is expected that two key provisions of this particular bill, relating to the windfall tax rate and the so-called cut-off price level (above which the higher state tax is to be applied), will be reduced. In this event, the impact on oil company profits would be less than in the example noted as "worst case" in our earlier memorandum.(1) We expect sentiment to ebb and flow at any given point in time on the issue of what could be the worst case. For instance, last Friday's liberal democratic Anchorage Daily News carried an article regarding possible legislation in the House more radical than Senator Huber's.

Senator Huber's severance tax bill was introduced onto the floor of the Legislature last Friday, January 23, and his remaining bills, unless they have to be redrafted, will be introduced to the State Senate and House late this week. At that point, the first of three readings will begin, comments received from interested parties, and the legislation will begin to be shuttled back and forth between various relevant committees.(2)

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(1) We used a 37.5% excess profits tax and a cut-off price in California of $8.00/bbl. Based on a $12.00/bbl delivered price in California, this resulted in a Prudhoe Bay producing profit of $2.46/bbl. At $9.00/bbl delivered price, profits were reduced to $1.74/bbl.

(2) Appendix 1 lists the key committees and committee members in both the House and Senate. It will be noted that Senator Huber is prominent as Vice Chairman of the State Affairs Committee, is Chairman of the Special Committee on Tax and Revenue~~, and is a member of the important Resources Committee~~.

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Regarding the Anchorage Daily News article and oil legislation emanating directly from the House, Representative Steve Cowper (pronounced Cooper), who is Vice Chairman of a briefly convened House Finance Subcommittee on Tax and Revenue, is working on a bill roughly paralleling Senator Huber's. We have talked to Representative Cowper on the telephone. His legislation is lagging Senator Huber's from a timing (perhaps ten days to two weeks) and procedural standpoint. It also faces potential opposition from House committees before it reaches the floor. The House Finance Committee, chairmanned by Hugh Malone, is expected to recommend floor consideration but the House Resources Committee, whose Chairman is Representative Neis Anderson (a native corporation legislator) will provide a more difficult test. The latter committee, which also is composed of conservative rural and business-oriented members, probably will hold extensive hearings, and an adverse recommendation for floor consideration is possible. We do not know the exact nature of Cowper's developing legislation but his economic research has been prepared by Michael Tanzer Economic Associates of New York City. We have not yet received a copy of the so-called Tanzer Report, which recently has been released in Juneau to all interested parties, but understand that it has a strong anti-oil industry bias in its analysis of oil company profitability in Alaska.

As noted earlier, passage of either Huber's or Cowper's oil legislation (or a combination of both) seems unlikely to occur for at least 60 days. Thus, resolution of the excess profits tax issue may not take place until early April. We will monitor developments between now and then intensively and expect to have an increasingly clear idea of the direction and likelihood of excess profits legislation as time passes.

The following notes are directed toward two general areas, background/ sources and power structure analysis. In this connection and in appraising news from Juneau, it is important to distinguish between the various sources of information in terms of their particular bias. For instance, information emanating from Senator Huber's office may well represent the Senator's objectives rather than an unbiased appraisal of the facts. Similarly, information from local oil industry representatives may contain the reverse bias.

Individuals contacted during our recent trip to Alaska consisted of three basic groups. The first consisted of Senator Huber, his staff, and other members of the House and Senate. Of particular significance in the latter group was Senator Chancy Croft, who is President of the Senate and a key figure in the Legislature's power structure. The second contact area was with oil industry representatives in Juneau. The third was an experienced local businessman who has evaluated the Legislature for many years and is familiar with the state's political power base.

Our assessment of Senator John-Huber is that he is a tireless worker, a shrewd horse trader, and is getting a good deal of pleasure from his key role on this issue. Senator Huber, who is 51 years old and has worked his way up through the House to his present prominent position in the Senate, basically initiated the legislation last year that led to the reserve tax. He is viewed by some in Juneau as the power broker between the oil companies on one hand and Senator Chancy Croft and Representative Mike Bradner (the powerful Chairman of the House Ways and Means Committee) on the other hand. Croft and Bradner are both liberal Democrats and are believed to have higher political aspirations. While discussions were not held with Bradner, he is believed generally to reflect Croft's pro-Alaska, anti-oil industry bias. However, it should be recognized that if Croft or Bradner aspire to, say, the governorship or other higher political office, they should become increasingly sensitive to the political views of the Anchorage establishment -- the influential Republican Anchorage Times and the Anchorage financial community. This realpolitik could move Croft and Bradner into more conservative positions over the coming months.

Our conversation with Senator Croft indicated that he believes both the timber and fishing industries have exploited the State of Alaska in the past and he does not want this repeated by the oil industry. Thus, his public posture is that the oil companies should be taxed on such a basis as to produce a non-cyclical stream of substantial tax revenues, part of which can be set aside for future Alaskan generations when the oil runs out. He does not buy the argument that Alaska needs short-term revenues from lease bonuses, etc. and indicated that he feels positively inclined toward passage of all Huber's legislation. It was indicated that Bradner's public stance is roughly the same.

Our assessment of Huber's working staff on energy issues (consisting of two individuals, Ed Sterner, who does the basic economic research, and Frank Fleeks, a young lawyer who has researched the legal and constitutional background of Huber's proposed bills) is that they are, like Huber, extremely hard working and dedicated. They appear to be in their early or mid-20s. Their posture, generally speaking, is pro-Alaska and anti-oil company. We regard the general level of staff preparation, considering the staff's size and experience, as relatively high. It is our opinion, however, that the rationale for justifying a $7-$8/bbl cut-off price in California contains an important logical inconsistency. This delivered price level is considered to be that economic balancing point above which the oil companies earn an "excess" rate of return and below which the oil companies will be discouraged from investing in Alaska. The inconsistency obviously is that the $7-$8 figure is a delivered price before substantial transportation costs. Thus, to be logical, the bill should construe the $7-$8 cut-off price as representing a wellhead value, or conversely, if the cut-off price is to be a delivered price in California, transportation, etc. costs should be added to this level to establish an $11-$12 cut-off price in California. We assume that the staff is aware of this inconsistency and our discussions with Senator Huber seemed to validate our conclusion. Our appraisal of Senator Huber's reaction was that this is an area, together with the excess profits rate, where significant compromise could occur. Other areas of compromise might involve the inclusion of an inflation factor and possibly a related 3% price incentive along the lines of the recently passed Federal Energy Act.

Our assessment of the oil companies' power base, in terms of voting factors, is that it will depend heavily on the native corporation representatives in the House and the Senate and the degree to which the Anchorage establishment can be mobilized to exercise some degree of restraint over the prevailing liberal sentiment in the Legislature. Regarding the former, the native legislators represent about 20% of the 20-member Senate and 40-member House. These percentages, however, tend to conceal the actual strength of native representatives who control additional votes well above their numerical position. As implied earlier, the native corporations are expected to oppose Senator Huber and Representative Cowper's legislation on the grounds that it will discourage oil company development of their 40 million acres of land and negatively impact their net profit interests outside of Prudhoe Bay negotiated with various oil companies.

In order to get some form of his windfall legislation through the Senate and House, Huber will have to put together a strong liberal coalition to offset the native votes and their influence on other legislators. He also will have to counter what will probably be increasing conservative pressures from Anchorage. On the other side of the ledger, the oil companies will have to implement their point of view with great care so that their efforts do not result in the opposite effect they intend to create. Moreover, they must make the difficult decision by the time the direction of the legislation is established, whether to oppose it on principle as a form of confiscation, or to negotiate out the best deal they can obtain.

As noted in our January 16 Industry Commentary, we believe that the Federal government will evince increasing interest in this legislation, both from the standpoint of potential oil revenue loss from Alaska, and, perhaps more significantly, from the far greater potential loss that would occur if an Alaskan precedent were used by California, Texas and other lower-48 states to place a windfall tax on certain profit levels. Equally important, the Federal government must become increasingly concerned over its potential loss of control over the economic incentives of its energy legislation.

In summary, we expect that the next few weeks will represent a period of legislative uncertainty and flux for the oil industry, during which time the bad news may temporarily outweigh the good. As the legislative process progresses, however, we believe that reason will prevail as more conservative forces come into play, although an excess profits tax principle may well be established. We see no reason to change our conclusion expressed in our January 16 Industry Commentary that Arco and Sohio represent attractive long-term investments at current prices.

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Note: Wertheim & Co., Inc. and/or persons associated with it have a position in the common shares and/or options in Atlantic Richfield.

## APPENDIX 1

## SENATE

### Chancy Croft, President

| | |
|---|---|
| Finance | Ray (Chairman), Poland (Vice Chairman), Rader, Chance, Ferguson, Butrovich, Sackett. |
| Tax & Revenue(3) | Huber (Chairman). |
| Resources | Poland (Chairman), Meland (Vice Chairman), Croft, ~~Huber,~~ Rader, Rodey, Butrovich, Orsini. |
| Rules | Rader (Chairman), Kerttula (Vice Chairman), Ray, Croft, Sackett. |
| Commerce | Kerttula (Chairman), Willis (Vice Chairman), Ziegler, Colletta, Bradley. |
| Judiciary | Ziegler (Chairman), Meland (Vice Chairman), Poland, Miller, Tillion. |
| Community and Regional Affairs | Rodey (Chairman), Willis (Vice Chairman), Hohman, Tillion, Orsini. |
| State Affairs | Meland (Chairman), Huber (Vice Chairman), Ferguson, Colletta, Miller. |

(3) Special Committee, not a standing committee.

## APPENDIX 1

### HOUSE

### Mike Bradner, Chairman, Ways and Means Committee

| | |
|---|---|
| Finance | Malone (Chairman), Buchholdt (Vice Chairman), Itta, Cowper, Guy, Gruening, Duncan, Naughton, Haugen. |
| Tax and Revenue (4) | Cowper (Chairman). |
| Rules | Parker (Chairman), Cotten (Vice Chairman), Miller, Naughton, Specking. |
| Judiciary | Gardiner (Chairman), Bradley (Vice Chairman), Brown, Cotten, Parr, Eliason, Specking. |
| Resources | Anderson (Chairman), Smith (Vice Chairman), Osterback, Brown, Eliason, Hershberger, Rhode, Huntington, Swanson. |
| State Affairs | McKinnon (Chairman), Miller (Vice Chairman), Fischer, Wallis, H. Beirne, M. Beirne, Parker. |
| Commerce | Bradley (Chairman), Wallis (Vice Chairman), Freeman, Kelley, Rhode, Urion, Rudd, McKinnon, Fischer. |
| Community and Regional Affairs | Cotten (Chairman), Ostrosky (Vice Chairman), Freeman, Davis, Hershberger, Hackney, Ose, Rudd, Kelley. |

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(4) Finance Subcommittee.

Research Department

Wertheim

**Industry Commentary**

Joseph S. Clark, Jr.

February 6, 1976

# ALASKAN TAX LEGISLATION (III)

## THE TANZER REPORT

We continue to believe that the three key investment variables of the oil industry at the present time are (1) the world price of crude oil; (2) legislative developments in Washington; and (3) the progress and profitability of North Slope oil. The Alaskan Legislature's tax proposals represent the most important current development affecting the third key variable.

Moreover, as noted in our January 16 and January 27 Industry Commentaries, if the State of Alaska succeeds in establishing the precedent of excess profits taxation, an investor must raise the question as to the possibility of state taxation above certain levels in the lower-48 producing states. The issue, of course, transcends the oil industry and relates to all domestic extractive industries. Particularly vulnerable would be integrated companies in the forest products, non-ferrous metals, and coal industries where fabrication and/or marketing facilities downstream are subsidized by higher rate of return extractive operations upstream. To choose a random example, one wonders what the State of Washington's reaction to Weyerhaeuser's timbering profits (1) would be if Alaska passed an excess profits tax. As noted in our earlier Industry Commentaries, we believe that such an Alaskan precedent, if established, ultimately would result in a constitutional Federal vs. states rights conflict. We continue to believe that in such a confrontation the Federal government would prevail.

In view of the preceding comments, as well as the more direct implications for Arco, Sohio and Exxon, we expect to continue to monitor developments in Juneau closely.

The Tanzer Report is a highly-detailed study of potential oil company profitability from the Prudhoe Bay field, prepared for Representative Steve

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(1) Weyerhaeuser owns most of its timbering land in this area (in contrast to state-owned land in the case of Prudhoe Bay), but the analogy still seems valid since the Alaskan oil rights were "sold" pursuant to leases.

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Cowper,(2) Chairman of the Legislature's House Subcommittee on Revenue Sources,by Michael Tanzer Associates, a petroleum consulting firm in New York City. It seems unnecessary to dwell on the report's strong anti-oil company bias, its outdated investment figures for the Prudhoe Bay field, and its exclusion of the Alyeska Pipeline from the rate of return analysis. The full report, which is 195 pages long, is an extensive, scholarly, and sophisticated document, skillfully written to appeal to the individualistic aspirations of many Alaskan legislators, while at the same time advocating increased state involvement in the oil and gas industry. Its significance lies in its premise that profits above a certain return on investment within a discrete geographical area (i.e., the Prudhoe Bay field) should be subject to a state "windfall" tax. As such, the report parallels Senator Huber's staff work, which leans more heavily on the concept of an "energy equilibrium" excess profits price of $7-$8 per barrel delivered in California. While purportedly not to be used as a model for legislation, the Tanzer Report is bound to have an impact on the thinking of the Alaskan Legislature, but has not, as far as we have been able to determine, received wide publicity in the lower-48 states. The report may be summarized briefly as follows:(3)

Pre-tax wellhead profitability is calculated for Sohio/BP, Arco, and Exxon at three arbitrary delivered prices in California, $10, $13, and $16 per barrel. Total transportation costs from Prudhoe Bay to Los Angeles are estimated at about $4.00 per barrel over the life of the field: $0.50 for tankers and $3.50 for the pipeline tariff. Subtracting these costs from delivered prices, wellhead values of $6.00, $9.00 and $12.00 per barrel, respectively, are derived. Deducting present Alaskan royalty and severance taxes of about 20% of wellhead values and operating costs of $0.50 per barrel, company gross profits, before state and Federal income taxes, are computed to be $4.30 per barrel, $6.70, and $9.70 per barrel, respectively.

Company capital investment in Prudhoe Bay by the end of 1976 is estimated at $1.9 billion. By mid-1978, cumulative investment is projected to rise to $2.5 billion,(4) increasing to $3.1 billion through the year 1982. Post-1977 capital and operating costs are based in part on data provided by

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(2) See Wertheim & Co., Inc. Industry Commentary, <u>Alaskan Tax Legislation (II)</u>, dated 1/27/76, for a detailed outline of key legislators and committees in the State Senate and House.

(3) Appendices A and B provide further summary detail. Appendix A presents Tanzer's own summary and Representative Cowper's 1/20/76 covering letter to Senator Croft and Representative Bradner enclosing the complete report. Appendix B is Senator Huber's staff's appraisal of the report which basically endorses Tanzer's approach.

(4) At the present time, cumulative capital investment for the three companies in Prudhoe Bay seems almost certain to exceed $3.4 billion by the end of 1977.

the engineering firm H. J. Gruy Associates, and all capital costs are converted to a post-tax basis to reflect Federal tax deductions for intangible drilling costs, etc. prior to the discounted cash flow rate of return analysis.

Given the preceding assumptions, the following table summarizes the Tanzer Report's conclusions regarding industry profitability at the three assumed delivered price levels in California, expressed in terms of annual discounted cash flow rate of return. Three arbitrary assumptions with respect to state income taxation are used -- an "existing" effective state tax of 5% (Case A-our own designation), a state income tax of 50% over the life of the field (Case B), and a state income tax of 50% through the year 1985 increasing to 80% over the balance of the field's life (Case C):

Rate Of Return On Field Investment

| State Tax | $10.00/Barrel | $13.00/Barrel | $16.00/Barrel |
|---|---|---|---|
| | (Delivered Price in California) | | |
| Case A | 28% | 35% | 40% |
| Case B | 19 | 25 | 30 |
| Case C | 18 | 24 | 29 |

It can be seen that Tanzer's calculations show that oil company rates of profitability, even under high state income tax assumptions, range from 18% to 29% annually.

Three major additional conclusions are reached in the report:

1. Case B or C levels of taxation will not cause the oil companies to abandon Prudhoe Bay investment. This is not so much because of enormous sunk costs, but rather because alternative high rate of return producing opportunities elsewhere in the world are not available. Another reason is that the preceding rates of return are well above historical earnings on total capital investment for Sohio/BP, Arco, and Exxon -- the "minimal acceptable profit rate" thesis.

2. Major state tax increases are fair because of precedents in Norway, the U. K., and elsewhere. Underlying this argument is the doctrine of changing circumstances, the fact that Prudhoe Bay is on state-owned land, and the concept that "the State and its people are the ultimate owner of the resources in the ground."

3. The State of Alaska should consider investing in Alaskan oil exploration and development, particularly in view of the fact that the "profit rates the oil companies seek are clearly far higher than the State's cost of capital."

A

The preceding summary of the Tanzer Report may well indicate a degree of naivete which is not present in the original document. A careful reading of the report as a whole suggests that just the opposite is the case. Its premise, however, that the State of Alaska has the right to what amounts to an equity interest in Prudhoe Bay, without having advanced risk capital, runs counter to the American tradition of free enterprise.

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APPENDIX A

Alaska State Legislature

REPRESENTATIVE
STEVE COWPER
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FAIRBANKS, ALASKA 99701

WHILE IN JUNEAU
POUCH V
JUNEAU, ALASKA
99811

House of Representatives

January 20, 1976

Senator Chancy Croft
President of the Senate
Alaska State Legislature

Representative Mike Bradner
Speaker of the House
Alaska State Legislature

Gentlemen:

I am enclosing herewith a report entitled Alaska Prudhoe Bay Oil: Profitability and Taxation Potential, prepared by Tanzer Economic Associates, Inc., pursuant to a contract with the Legislative Affairs Agency.

The report is a survey of the profitability of oil production in the Sadlerochit formation by Sohio/BP, ARCO, and Exxon, which together own approximately 96% of the leases which are the subject of the report. The analysis is based in large part upon figures provided by the three companies involved, by the State Division of Oil and Gas, and by Gruy and Associates.

It should be clearly emphasized that the tax rates used in the models for the study are not indicative of legislative direction, but are figures arbitrarily chosen for the purpose of illustrating the effect of state taxation upon profitability. See, i.e., page 66 of the study. The rates will not provide a departure point for proposed legislation; in fact they were not meant to be used for that purpose.

A copy of the report is being sent to the major oil companies, along with a request that each company set forth its objections to the projections contained therein.

Very truly yours,

Steve Cowper
Chairman, Subcommittee on
Revenue Sources
House Finance Committee

SC:jab

## SUMMARY

The purpose of this Study was to analyze potential oil company profitability from Prudhoe Bay crude oil, as a guide to potential taxation of such profitability by the State of Alaska. The general approach was that estimates were made of the aggregate investment costs and potential profits for Sohio/BP, Arco and Exxon, together, who share an estimated 95% of Prudhoe Bay oil. All estimates were put on an annual after-tax basis for the 1964-95 period, in order to allow estimation of the companies' profit rates on a discounted cash flow (DCF) basis; this basis systematically takes into account the time value of money and is the compound interest profit calculation method used by the companies themselves. Calculations were then made of the effects of different State income tax rates on the companies' DCF profit rate and on the division of the Prudhoe Bay "oil pie" among the companies, the State and the Federal Government, respectively. In all cases an attempt was made to be conservative in estimating future company profitability.

Specifically, the Study first estimated per barrel wellhead values of Prudhoe Bay crude oil, by subtracting projected marine and pipeline transport charges from the delivered price in the Los Angeles area; throughout the

Study three possible Los Angeles prices were considered, with a medium price of $13 per barrel and a low of $10 and a high of $16 (each held constant for the 1977-95 period). Total annual wellhead values were then estimated for the companies' 95% of the production from the Sadlerochit formation only , which was assumed to begin in 1977, peak at 1.7 million barrels per day in 1987, and drop at 15% per year thereafter (with the Study cutting off at 1995).

After subtracting from the wellhead values State royalty and severance taxes (estimated together at 20%) and current production costs, there were three gross profit series for the 1977-95 period (varying with price). Each of these series was assumed to be subjected to three possible effective State corporate income tax rates: 5% (as a rough measure of the existing tax structure), 50%, and 50% until 1985 and 80% thereafter. With an assumed Federal tax rate of 48%, calculations were then made of the nine possible after-tax profit series for the companies in the 1977-95 period. Each of these series was combined with the one estimated annual after-tax investment series for Prudhoe Bay. The result was nine possible company net cash flow series, each of which was subjected to DCF profitability analysis.

The Study's quantitative conclusions were as follows. First, under present tax conditions, the companies' DCF profit rates would be between 28% and 40% per year (compounded), with 35% per year being the profit rate under the medium price assumption. Over the whole 1977-95 period, for a total investment of about $3 billion, the companies would net between $ 17 billion and $36 billion, with $26 billion being the medium price figure. Of a total Prudhoe Bay oil pie of between $44 and $93 billion (depending again on prices), the companies would get about 38%, the Federal Government 36%, and the State of Alaska only 26% (including severance and royalty).

Second, increasing the effective State corporate income tax rate from 5% to 50 % would still leave the companies a DCF profit rate of between 19% and 30% per year, with 25% in the medium price case. While the companies' profits would fall by half, they would still net between $9 and $19 billion. The State, however, would increase its total oil revenues sharply; for example, for the medium price case, they would rise from $18 billion to $42 billion. On average the State's share of the oil pie would jump to 61%, while the companies' share fell to 20% and the Federal Government's to 19%.

Third, the Study showed that under DCF methods of profit calculation, at high profit rates for the companies, cash inflows in later years have relatively little present value to them. Thus, an increase in the State corporate income tax rate from 50% in 1977-85 to 80% in 1986-95 would reduce the companies' DCF profit rates by only one percentage point. At the same time, the State's total oil revenues for the whole 1977-95 period would increase by about 25%. Under the sequential 50%:80% tax rate the State's share of the oil pie would increase to 71% while the companies' would fall to 15% and the Federal Government's to 14%. This illustrates the general principle that company profits in later years can be heavily taxed without affecting their present exploration and development incentives.

The Study also analyzed and discussed a number of qualitative questions. As regards possible mechanisms for future State oil profit taxation, it was concluded that an income tax, a severance tax, and a value added tax, would have similar effects in practice, while a reserves tax would be harmful. On the question of the effect of increased State taxes on the companies' exploration and development incentives, it was concluded that the likely profit rates, even after the tax increases, were probably sufficiently high to be adequate. The question as to the "fairness" of increasing company taxes was also considered. While this is largely a "value judgment" question, it was noted that without increased State tax rates the companies will be the prime beneficiaries of the windfall profits which have arisen from the quadrupling of oil prices by OPEC since late 1973, despite the fact that the oil lands belong to the State. It was further shown that even non-OPEC Governments, such as in Norway and Great Britain, have moved to capture a larger part of these windfall profits by increased taxes on the oil companies.

The Study concluded with some general observations about future State oil policy. Two related questions were considered: how should the State use its increased future oil revenues, and should it move beyond being a passive royalty and tax collector and take a more active role in the oil sector. The Study's view was that in order to prevent Alaska's increased State oil revenues from being simply dissipated in inflation and/or a short-lived boom, with most of the money ultimately flowing out of the State, the State would have to play a more active role to help coordinate long run economic development. Moreover, a logical place for the State to utilize its oil revenues would be in the oil sector itself.

Thus, for example, the State should consider possibilities for investing in oil exploration and development in Alaska, either through joint ventures with oil companies or by contracting directly with specialized drilling companies (or the State might invest in refineries, petrochemicals, etc.). This might be particularly appropriate since the profit rates the oil companies seek are clearly far higher than the State's cost of capital. It was maintained that in recent years there has been a wider dispersion of oil knowledge and technological capability, and that it might be useful for the State to examine the recent successful experience of Government oil companies in countries like Mexico and India.

Finally, the Study concluded that in order for the people of Alaska and their representatives to make informed decisions about future State oil policy, a great deal more knowledge was needed by them; even if the ultimate decision is to remain a passive tax collector, such knowledge would help the State to maximize its benefits from this role. Informed policy decisions are particularly crucial in the oil sector because this is a non-renewable resource, the benefits of which belong not only to present but also future generations.

ALASKA
STATE LEGISLATURE

APPENDIX B

# MEMORANDUM

January 26, 1976

TO: Senate President Chancy Croft

FROM: Franklin D. Fleeks
Tax Counsel, Committee on Taxation and Revenue

SUBJECT: Summary of the Tanzer Report and Comparison with Committee's Proposed Legislation

Senator Huber has directed that the attached staff report be prepared to familiarize you and the Committee members with the contents of the Tanzer report. This report was prepared under a contract with the Legislative Council Subcommittee on Taxation and Revenue, chaired by Senator John Huber. The supervision of the Tanzer contract was accomplished by vice chairman Representative Steve Cowper.

In addition, comparison was made with the proposed legislation drafted by this Committee. The report is submitted for information and comment.

# SUMMARY OF THE TANZER REPORT
# AND A COMPARISON OF ITS CONCLUSIONS WITH THE
# INTERIM SUBCOMMITTEE ON TAXATION AND REVENUE PROPOSED LEGISLATION

Prepared by:

Edwin Sterner
Research Analyst

## Summary of the Tanzer Report

The Tanzer Economic Associates report, "Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential," shows what has always been suspected. Prudhoe Bay will be a massively profitable venture which can supply the state with large revenues and still provide a favorable return on investments made. The Report's conclusions are strikingly similar to the conclusions upon which our proposed legislation is based.

Under the current state and federal tax structure, Prudhoe Bay will probably yield discounted cash flow (DCF) profitability rates of 28%, 35%, or 40% if oil sells on the west coast for $10, $13, or $16 respectively (p. 51). (For a discussion of the DCF method of analysis, see III.A., pp. 32-36 of the report.) Such rates of return should be more than adequate incentives for exploration and development and could sustain much higher rates of taxation.

As an example, the profits of the field are taxed at a 50% state income tax rate. Assuming that the tax would actually be effective at that rate, DCF profitability rates for $10, $13, and $16 oil drop to 19%, 25%, and 30% respectively (p. 60).

In a final case, the Report shows that the value of the investment would fall very little if a tax rate even higher than 50% were levied several years after the investment started yielding positive cash flows. In a simple case, one would probably still invest in a bank account that would have a net yield of 20% per year compounded for eight years, even if one knew that after eight years, the earnings would be taxed at 80%.

For the example used, the first eight years of Prudhoe Bay production are subject to the 50% income tax rate, and after eight years to an 80% income tax. This reduces the DCF profitability rates by only one percent to 18%, 24%, and 29% for the three prices.

In all cases, the rates of return should sustain exploration and development. The report concludes that if they are not sufficient, perhaps the state should consider financing at least the exploration phase of petroleum development.

## Comparison of Tanzer Report Conclusions with the Interim Subcommittee's Proposed Legislation

The proposed tax legislation is quite similar to the Report's examples. The proposed legislation suggests a 50% income tax rate on most income from Prudhoe Bay. Due to the fact that the income tax has been ineffective in the past, a tax is proposed which works like a severance tax with deductions for capital and operating expenses incurred only in Alaska. This method was chosen because it "automatically" fine tunes to the costs of each field and avoids the need to adjust rates for each field to treat them basically the same.

There are differences, however. These are more in method than in principle. A flat 50% tax would tax oil profits at 50% even if prices should fall. Although a large fall in prices is unlikely, the law should be prepared to react to it (especially in view of the national temperament and the mood of Congress). The point of the law is to raise revenues, not be vindictive. From the costs of Prudhoe Bay and its transportation, it appears that should prices for Alaskan oil fall, or be forced to

-fall, below seven to eight dollars per barrel on the west coast, returns to investment would be at levels where only the "normal" rates of corporate taxation could be warranted. Thus, there is a "circuit breaker" which in effect causes net income due to a west coast price of seven to eight dollars to be taxed at the regular state corporate rate of 9.4% and net income due to a higher price at 50%.

The report also assumes that severance taxes will not be changed. The legislation proposes that the basic severance tax rates be increased by approximately 60% for Prudhoe Bay oil. This would cause the state's royalty and severance tax portion of the wellhead value to rise from the 20% figure used in the report (p.56) to 23-24%. This tends to offset the fact that the "circuit breaker" keeps the average rate of net tax below 50%.

Finally the report suggests the possibility of using a system of tax rates graduated over a period of time. The problem with this seems to be administrative, and if it can be worked out, might be most valuable to the state. The example used suggests that after a certain number of years, a field would be subject to higher tax rates. Indeed, every few years, or even every year, the rates could be higher. This could raise significant problems, if as the higher tax years approach major investments are required to maintain the field. For instance, in the year before the higher taxes are imposed on Prudhoe Bay in the example, 227 million dollars in new wells are required. Anticipating the next year's higher tax rates, the producer might choose to shift that investment to a "new" field elsewhere, which is not subject to the higher tax for several years. A proliferation of "new" fields and prematurely declining old fields might result. This possibility could be avoided by allowing production in an "old" field which is due to new investment to be taxed at the lower rates. The problems in determining what oil is due to "old" or "new" investment are obvious.

Although it does not allow the wide variation in rates such as the 50/80% report example implies, accelerated depreciation does much the same thing. It lowers the effective tax rates early in the life of the field and raises the rates when the accelerated depreciation is exhausted. Its common use and familiarity lends it to this situation. Since such higher rates would be some years off, implementation would not be needed now. The experiences of Norway and any others who are attempting this type of taxation should be watched closely.

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PETROLEUM INDUSTRY: Thoughts on Alaska and the U.S. Oil Economy J. Fischer

The Alaskan legislature is soon to begin deliberating a package of tax proposals designed to sharply (300%+) increase the state's anticipated tax revenues from the Prudhoe Bay field. These revenues will be apart from the state's royalty interest (12½%) in oil and gas production. The proposals encompass a modification of the corporate income tax structure, an increase in the severance tax, and the introduction of a steep excess-profits tax. The excess-profits tax, apparently to be in the range of 41-50%, would apply to the difference between the market value of North Slope oil delivered to the West Coast and a deemed value beginning at $7 a barrel (the 1974 base level, we infer) and escalating over time. (The 50%, which we have seen in the literature, may include the state income tax of 9.4%.) The impact of these tax changes on the prospective earnings of the North Slope operators is discussed in a separate Note. We are concerned here with the broader implications of the proposed excess-profits tax.

We note that the issue of "Alaskan participation" arose once before, in 1972, when Alaska sought complete control over the pipeline right-of-way and an undivided 20% interest in the pipeline, while proposing a steeply progressive tax on pipeline earnings and a minimum take at the well head from royalty and severance tax payments. Alaska was then concerned that the pipeline would emerge as the principal profit center. It is now clear that unless OPEC prices should crack (which we deem improbable), the wellhead will prove to be the principal profit center. (The increase in the West Coast price of "new crude", even as modified by the new energy legislation, will have more than compensated for the escalation of pipeline construction costs, as reflected in the TAPS tariff.)

The companies are in a poor bargaining position today, as compared with 1972. The pipeline was then a concept. Today, the principal costs for transportation are sunk or firmly committed. Development of production facilities is well underway. The price of North Slope crude, on the West Coast or in the Midwest, will be governed by FEA ceilings (or one determined by Congress) for the initial years of production, and probably longer. The incidence of an excess-profits tax cannot be shifted. Alaska will be taxing an economic rent, and taxing it severely.

Alaska is apparently prepared to prescribe a "just price" for North Slope crude on the West Coast. We presume that the tax committees of the legislature will eventually prescribe a just price for natural gas as well. We note that the concept of the just price is an anathema to economists, except for regulated utilities. We doubt very much that Alaska will be prepared to sell its royalty oil and gas at the just price that will be controlling for tax purposes.

The thrust of the excess-profits tax mechanism appears to be to permit the North Slope companies to recover their capital and operating costs (including severance

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tax) and to make $1 a barrel, pre-tax, before the bite of state income, state excess-profits, and federal income taxes. Prospectively, a critical question will be the rate at which the base price will be permitted to escalate relative to the prescribed market escalation for new crude.

The $7 base price runs counter to the intent of national economic policy. Let us assume that with plausible escalation the base price is now roughly in line with the February 1 national composite of $7.66 a barrel. However, Congress has not prescribed a rollback in the benchmark price for new crude to $7.66 a barrel; the rollback will be to $11.28. In short, Congress would permit producers of new crude at difficult frontiers to earn a superior return. One may call this incentive pricing and/or a reward for risk-taking. Alaska would take a large chunk of this back.

Economic returns that could be applied for exploration and development in Alaska, off the West Coast and off the Atlantic Coast, or applied for investment in enhanced recovery techniques or in "synthetic" energy fuels will, instead, go to fund social services in Alaska. Alaska appears prepared to seek to maximize its take from the presently proved reserves on the North Slope. The state would appear to be disregarding the disincentive it is creating for probing for additional reserves, onshore or offshore, on state leases. It may well be irrational--from the standpoint of return on capital--for the companies to drill in the Beaufort Sea, or for ARCO to continue exploration west of Prudhoe Bay.

We presume to compare Alaska's perceptions to those of many of the OPEC nations. The oil and gas will be leaving Alaska and the economic benefits conferred by these hydrocarbons will be realized by the "importing states." In contrast, Texas, Louisiana, California and other producing states enjoyed a surge of economic development within their own borders on exploiting indigenous resources. Alaska will probably never enjoy the economic and social benefits attending major investments in refineries and petrochemical plants. (It will also be spared the social costs, such as pollution, attending these same investments.)

Alaska may also believe that, like Norway and the United Kingdom, it is entitled to tax away a substantial portion of a windfall gain that has resulted from OPEC's pricing power. However, the analogy cannot be pushed too far. Britain and Norway have both continued to exhibit a decent respect for maintaining investment incentive. Moreover, these are sovereign nations and their oil-taxing policy is integrated with national energy policies. In contrast, Alaska would appear to be flouting the goals of emergent U.S. energy policy.

Under Alaska's proposed tax package, the state's take per barrel would be larger than that of the Federal Government. This prospect is not likely to bring joy to Washington. Moreover, the proposed excess-profits tax would appear to be much more onerous than that proposed in Congress for the U.S. petroleum industry as an entirety. There appears to be no plowback provision--credits for a range of eligible investments. Moreover, the tax-writing authorities in Washington were prepared to accord special treatment for new crude.

The timing of the Alaskan proposals is most unfortunate. It comes when the companies are most concerned with completing financing arrangements for bringing North Slope oil to market and when the FPC has just voided the advance-payments program for much of the North Slope gas. We presume that the state is preoccupied with firming up its revenue expectations in order to facilitate borrowing for its internal needs.

We are especially concerned that other states exporting oil and gas--most notably Texas and Louisiana--may eventually seek to emulate Alaska. In retrospect, they have been very generous to consumers in their revenue claims. Perhaps fortunately, the increasingly important Federal domain is beyond their grasp. The severance tax is a powerful

Continued.............................

weapon. Imaginative tax experts can find any number of techniques for taxing economic rents on both old and new production. All producers except marginal operators may then be in an unfortunate position. The nation would ultimately be the loser, for exploration effort would inevitably slacken.

Initially, then, the North Slope producers and Alaska are once again found in an adversary position. Considerations of national energy policy may before long find the Federal Government and Alaska in an adversary relationship also. Eventually, the conflicting claims can encompass other states as well. These conflicts would be bearish for the industry. One can study the unfortunate position of the Canadian petroleum industry as Canada's Provinces and its Federal Government clash over shares in revenues. Periodically, the principal actors recall that the producers should be assured "adequate" returns.

The North Slope operators may well rue the day that Alaska became a state, but that is a bygone. Because of the companies' weak bargaining position in Alaska, their principal recourse is likely to be found in the Federal courts. We do not pretend to be experts at constitutional law. We anticipate, however, that a constitutional issue may be raised about the taxing of an economic value that arises beyond the state border, in the stream of interstate commerce. The companies may also allege that by creating a disincentive for further exploration effort, the excess-profits tax creates an undue restraint upon normal trade among the states.

Congress and the Administration may choose to exert pressure on behalf of the companies also. As a developing state, Alaska is not immune to the lure of proferred federal largesse or indifferent to its denial (as constrained by law). The pressure is most likely to be exerted if requested by the FEA or other producing states; political realities militate against the operators being helped by Congress in response to their own appeal. Equity for oil companies is not an attractive issue.

POINT OF VIEW

Only two weeks ago investors were concerned over how North Slope oil would fare at the hands of the Congress in 1977 under the pricing constraint imposed by the new energy Act. Today, they are worried about Alaska. Unfortunately, it will take time for the Alaskan legislature to debate, modify and enact the new tax proposals, and it will take time for the operators to prepare their appeal for relief. There is no urgency; production will not begin until the latter part of 1977. Only owners of Atlantic Richfield ($88), Standard of Ohio ($68 1/4), Exxon ($92 1/8) and BP ($11 5/8) may have a sense of urgency--especially owners of ARCO and Sohio.

We profess to optimism about the ultimate outcome, perhaps naively, because we would like to believe that state and national policies will recognize the case for rewarding exploration effort at difficult frontiers. Otherwise, we are all in for trouble. If a giant discovery like the North Slope is not allowed a superior rate of return, there is no reason for private capital to undertake exploration risk or for investors to own oil equities except as engines for cash flow over a finite

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period of resource life. If the earnings prospects of the incremental producers are to be slashed, one might as well restrict one's investments to companies with a strong position in old reserves in the lower 48 states. If one is concerned that other states will emulate Alaska, perhaps the entire group should be avoided--certainly, the domestics. Perhaps only the internationals should be bought and held for superior yields and a total return expectation.

There is no denying that the past investment allure of the North Slope oils has been tarnished, probably irrevocably. We sincerely hope that Alaska will not look to British Columbia as a model for virtue or guidance. In that unhappy circumstance, the North Slope operators may yet ponder whether their shareholders might not be better served if their resource bases were to be nationalized.

MEMORANDUM
FROM THE RESEARCH DEPARTMENT

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November 19, 1975

# THE TRANS-ALASKA PIPELINE AND PRUDHOE BAY CRUDE OIL PRODUCTION ANALYSIS OF UNIT COSTS AND PROFIT POTENTIAL

There is considerable investor interest in the cost of building and operating the Trans-Alaska Pipeline, the profit to be derived from the line, and the potential profitability from crude oil production in the Prudhoe Bay Field on the North Slope. In order to provide some perspective on these questions, we have compiled several tables that summarize the latest data on pipeline costs, as well as our estimates of the unit tariff that might be established for transporting crude oil through the pipeline. When combined with the selling prices in Los Angeles, these pipeline estimates should provide an indication of the wellhead value and profit potential for North Slope crude oil production (on the assumption that all oil is tankered to the Los Angeles market). We still expect the pipeline to be completed by late 1976 or the spring of 1977 and think that testing should be completed by the summer of 1977. Initial production should start in 1977, and we expect throughput to reach 1,200,000 b/d in the winter of 1977 - 1978. Profits to the operating companies could be limited in 1977 but should be substantial in 1978. Thus far, 320 miles of the total 800 mile pipeline has been installed. In some weeks, as much as 35 miles of pipe has been laid. Considering the road construction, ditching, vertical supports, and terminal facilities, about 50% of the total construction had been completed as of October 27, 1975.

## UNIT PIPELINE COSTS AND SELLING PRICES

Unit pipeline costs will be importantly influenced by the level of production. Therefore, we have developed cost estimates based on three different production levels; 1,200,000 b/d, 1,500,000 b/d and 2,000,000 b/d. The cost figures used are the latest available official estimates prepared by Alyeska Pipeline, increased by a 5% contingency factor and the cost of additional pumping stations to expand throughput. The pipeline will be a common carrier and should return a good profit to the owners. The current ownership of the Trans Alaska Pipeline is shown on the following page.

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## OWNERSHIP OF THE TRANS-ALASKA PIPELINE

| Common Share Price 11/14/75 | | % |
|---|---|---|
| 72 | Standard of Ohio | 33.34% |
| 93 | Atlantic Richfield | 21.00 |
| 88 | Exxon | 20.00 |
| 12 | British Petroleum | 15.84 |
| 46 | Mobil | 5.00 |
| 43 | Union | 1.66 |
| 52 | Phillips | 1.66 |
| 16 | Amerada Hess | 1.50 |
| | | 100.00% |

While production volumes and pipeline tariffs lend themselves to reasonably accurate estimates, the question of future crude oil selling prices is more uncertain and, of course, a most important variable. At this time, there is considerable controversy as to where crude oil prices will be in three or four years. Prices on the West Coast will reflect not only the level established by U.S. Government controls but foreign price trends as well. There is a minority viewpoint that foreign oil prices will decline substantially from present levels as a result of sluggish consumer demand and new production coming on from non-OPEC sources. To us, this thesis is hard to accept, and we would be surprised if foreign oil prices dropped sharply from current levels. Landed prices for foreign crude oil on the West Coast are generally in the range of $13.00 - $14.00/barrel exclusive of the present $2.00/barrel supplementary import fee. Domestic crudes have been selling as high as $13.50/barrel but may be rolled back to the area of $11.28/barrel under proposed legislation. In order to cover a broad price range, we are including in our statistical model prices from $8.00 to $13.00/barrel and the estimated profit potential at each level. Our long range thinking is that future price levels in the Los Angeles Basin will be in the general area of $11.00 to $12.00/barrel, and we would key in on the potential profits indicated at these prices.

## PRUDHOE BAY UNIT

It is generally estimated that the Prudhoe Bay Field has recoverable reserves of almost 10.0 billion barrels, which can be produced at a rate of 1,500,000 b/d. Ownership distribution of the Prudhoe Bay Unit (a unitized group of owners of the field) has been under study for almost five years, and a preliminary ownership breakdown should be available in the near future. To arrive at a meaningful judgement of the future earnings potential indicated for each of the major participants in the Unit, we have listed below those companies that have reported North Slope oil reserves and have related these figures to the estimated reserves for the entire field. Thus, we have arrived at the following working estimates of the ownership of production from the Prudhoe Bay Unit. The uncertain nature of the estimates deserves emphasis.

### ESTIMATED OWNERSHIP OF THE PRUDHOE BAY FIELD

|  | Gross Reserves (Billion Barrels) | % |
|---|---|---|
| Standard of Ohio | 5.100 | 51.0 |
| Atlantic Richfield | 1.970 | 19.7 |
| Exxon | 1.970 | 19.7 |
| Mobil | .325 | 3.3 |
| Phillips | .290 | 2.9 |
| Other * | .345 | 3.4 |
| Total | 10.000 | 100.0 |

*Primarily Amerada Hess, Louisiana Land (23) and Getty (169).

## EARNINGS IMPACT FOR EACH PARTICIPANT

Each member of the Prudhoe Bay Unit will be responsible for the marketing of its gross share of the oil produced. We have made a series of per share earnings estimates for both oil production and ownership of the pipeline based on varying levels of production and selling prices. These estimates are reproduced in the final three tables of this report and should be regarded as a final summary of the numerous variables which have to be reconciled in this exercise.

## SUMMARY

Because of the rising costs of building the pipeline and developing the Prudhoe Bay Field and the changing tax structure for the industry, the initial per barrel cost for North Slope oil has risen sharply over the past few years. Since oil was first discovered on the North Slope, the depletion allowance has been stricken from the federal tax law and the State of Alaska has increased its severance tax to 8%. We would not rule out some further changes in the tax laws. To us, the initial profit potential is far from being a "bonanza" and, if some Washington proponents of a crude oil price rollback are successful, the viability of producing and transporting North Slope oil and gas could be threatened. The same could be said if foreign oil prices drop sharply and bring down the domestic price structure. The latter threat may well be present for some time. We are encouraged that recently proposed legislation makes some allowance for high cost domestic oil such as that from the North Slope.

Based on production of 1,500,000 b/d and a selling price of $11.00/barrel, our calculations indicate an annual profit potential of $600 million from the pipeline and $1.2 billion from production, a total return of 18% on the estimated $10 billion initial investment; not a terribly attractive return based on the numerous political and economic risks involved, and well below our earlier estimates. In view of the declining profit return and the potential price threat, one could wonder if the entire North Slope/Trans Alaska pipeline project is attractive in view of the risks involved and available alternative investments.

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The final long-term merits of the entire Alaskan project will be importantly influenced by the future returns to be realized from the sale of known natural gas reserves and, of course, additional oil and gas discoveries which should be made on the North Slope. Prospects for the latter appear to be particularly attractive.

ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST

/bjg

## TRANS-ALASKA PIPELINE - 1,200,000 b/d

### Pipeline Costs:

| | $ Millions |
|---|---|
| Cost of Construction ($6,375 x 105% *) | 6,700 |
| Capitalized Interest (1974 - 1977) | 1,450 |
| Total | 8,150 |

### Annual Operating Costs:

| | |
|---|---|
| Pipeline Amortization - $8,150 x 92.5% ** ÷ 35 yrs. | 215 |
| Interest Costs at 10% x (85% of $8,150 million) *(a)* | 693 |
| Operating Costs (Labor, fuel, maintenance, etc.) | 70 |
| Ad Valorem Tax *(b)* | 160 |
| Income Taxes *(c)* | 431 |
| Net Profit - 7% x $8,150 million | 571 |
| Total Annual Costs | 2,140 |

| | |
|---|---|
| Pipeline Tariff Per Barrel (438,000,000 bbls./yr.)<br>(Includes a pipeline profit of $1.30) | $ 4.89 |

* *Allowance for contingency.*

** *Assumes 7.5% salvage value.*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production assets.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductable for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

### Per Barrel Profit on Gross Production:

| | | | | | | |
|---|---|---|---|---|---|---|
| Selling Price (Los Angeles) | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Pipeline Tariff | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 |
| Tanker to L. A. | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 |
| Indicated Wellhead Value | 2.60 | 3.60 | 4.60 | 5.60 | 6.60 | 7.60 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .33 | .45 | .58 | .70 | .83 | .95 |
| Severance Tax (8% of Wellhead Value) | .21 | .29 | .37 | .45 | .53 | .61 |
| Ad Valorem Tax *(a)* | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs | 1.13 | 1.33 | 1.54 | 1.74 | 1.95 | 2.15 |
| Operating Profit | 1.47 | 2.27 | 3.06 | 3.86 | 4.65 | 5.45 |
| Taxes at 53% *(b)* | .78 | 1.20 | 1.62 | 2.05 | 2.46 | 2.89 |
| Net Profit | $ .69 | $1.07 | $1.44 | $1.81 | $2.19 | $2.56 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plue 9.36% state tax (deductible for computing federal taxes).*

| | $ Millions |
|---|---|
| **Pipeline Costs:** | |
| Cost of Construction ($6,700 + $500) ................ | 7,200 |
| Capitalized Interest (1974 - 1977) ................. | 1,450 |
| Total ............................................ | 8,650 |
| **Annual Operating Costs:** | |
| Pipeline Amortization - $8,650 x 92.5% * ÷ 35 yrs. | 229 |
| Interest Costs @ 10% x (8,650 x 85%) *(a)* ........... | 735 |
| Operating Costs (Labor, fuel, maintenance, etc.) ... | 70 |
| Ad Valorem Tax *(b)* ................................ | 173 |
| Income Taxes *(c)* .................................. | 471 |
| Net Profit (7% x $8,650 million) ................... | 606 |
| Total Annual Costs ................................ | 2,284 |
| Pipeline Tariff Per Barrel (547,500,000 bbls./yr.)..<br>(Includes a pipeline profit of $1.11) | $ 4.17 |

* *Assumes 7.5% salvage value.*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production assets.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductible for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

Per Barrel Profit on Gross Production:

| | | | | | | |
|---|---|---|---|---|---|---|
| Selling Price (Los Angeles) ............. | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Pipeline Tariff .................... | 4.15 | 4.15 | 4.15 | 4.15 | 4.15 | 4.15 |
| Tanker to L. A. .................... | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation .................. | 4.65 | 4.65 | 4.65 | 4.65 | 4.65 | 4.65 |
| Indicated Wellhead Value ............... | 3.35 | 4.35 | 5.35 | 6.35 | 7.35 | 8.35 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .42 | .54 | .67 | .79 | .92 | 1.04 |
| Severance Tax (8% of Wellhead Value) | .26 | .35 | .43 | .51 | .59 | .67 |
| Ad Valorem Tax *(a)* ................ | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs ................. | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization ..................... | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs ................. | 1.27 | 1.48 | 1.69 | 1.89 | 2.10 | 2.30 |
| Operating Profit ...................... | 2.08 | 2.87 | 3.66 | 4.46 | 5.25 | 6.05 |
| Taxes at 53% *(b)* ...................... | 1.10 | 1.52 | 1.94 | 2.36 | 2.78 | 3.21 |
| Net Profit ........................... | $ .98 | $1.35 | $1.72 | $2.10 | $2.47 | $2.84 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plus 9.36% state tax (deductible for computing federal taxes).*

| Pipeline Costs: | $ Millions |
|---|---|
| Cost of Construction ($7,200 + $300) ............... | 7,500 |
| Capitalized Interest (1974 - 1977) .................. | 1,450 |
| Total ........................................ | 8,950 |

| Annual Operating Costs: | |
|---|---|
| Pipeline Amortization - $8,950 x 92.5% * ÷ 35 yrs. | 237 |
| Interest Costs @ 10% ($8,950 x 85%) *(a)*.............. | 761 |
| Operating Costs (Labor, fuel, maintenance, etc.) .... | 70 |
| Ad Valorem Tax *(b)* ................................ | 179 |
| Income Taxes *(c)* ................................. | 494 |
| Net Income (7% x $8,950) ........................... | 627 |
| Total Annual Costs ................................. | 2,368 |

Pipeline Tariff Per Barrel (730,000,000 bbls. per yr.) $ 3.24
(Includes a pipeline profit of $.86)

* *Assumes 7.5% salvage value*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production equipment.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductible for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

Per Barrel Profit on Gross Production:

| Selling Price (Los Angeles) ............. | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
|---|---|---|---|---|---|---|
| Pipeline Tariff ..................... | 3.25 | 3:25 | 3.25 | 3.25 | 3.25 | 3.25 |
| Tanker to L. A. ..................... | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation .................. | 3.75 | 3.75 | 3.75 | 3.75 | 3.75 | 3.75 |
| Indicated Wellhead Value ................ | 4.25 | 5.25 | 6.25 | 7.25 | 8.25 | 9.25 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .53 | .66 | .78 | .91 | 1.03 | 1.16 |
| Severance Tax (8% of Wellhead Value) | .34 | .42 | .50 | .58 | .66 | .74 |
| Ad Valorem Tax *(a)* ................. | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs ................... | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization ....................... | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs .................. | 1.46 | 1.67 | 1.87 | 2.08 | 2.28 | 2.49 |
| Operating Profit ....................... | 2.79 | 3.58 | 4.38 | 5.17 | 5.97 | 6.76 |
| Taxes at 53% *(b)* ...................... | 1.48 | 1.90 | 2.32 | 2.74 | 3.16 | 3.58 |
| Net Profit ............................. | $1.31 | $1.68 | $2.06 | $2.43 | $2.81 | $3.18 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plus 9.36% state tax (deductible for computing federal taxes).*

## GROSS PRODUCTION - 1,200,000 b/d (438,000,000 barrels/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| Selling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.0 |
| Unit Profit | .69 | 1.07 | 1.44 | 1.81 | 2.19 | 2.5 |

* * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio (38,256,000 shares) | 51.0 | 223.4 | $4.03 | $6.25 | $ 8.41 | $10.57 | $12.79 | $14.9 |
| Atlantic Richfield (57,834,000 shares) | 19.7 | 86.3 | 1.03 | 1.60 | 2.15 | 2.70 | 3.27 | 3.8 |
| Exxon (225,324,000 shares) | 19.7 | 86.3 | .26 | .41 | .55 | .69 | .84 | .9 |
| Mobil (102,289,000 shares) | 3.3 | 14.5 | .10 | .15 | .20 | .26 | .31 | .36 |
| Phillips (76,113,000 shares) | 2.9 | 12.7 | .12 | .18 | .24 | .30 | .37 | .43 |
| Total Production | 100.0 | 438.0 | | | | | | |

* * * * *

| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $190.0 | $4.98 | $4.98 | $ 4.98 | $ 4.98 | $ 4.98 | $ 4.98 |
| Atlantic Richfield | 21.00 | 120.0 | 2.07 | 2.07 | 2.07 | 2.07 | 2.07 | 2.07 |
| Exxon | 20.00 | 114.0 | .51 | .51 | .51 | .51 | .51 | .51 |
| Mobil | 5.00 | 29.0 | .28 | .28 | .28 | .28 | .28 | .28 |
| Phillips | 1.66 | 9.5 | .12 | .12 | .12 | .12 | .12 | .12 |
| Total | 100.00 | 571.0 | | | | | | |

* * * * *

| Total Profits | PER SHARE | | | | | |
|---|---|---|---|---|---|---|
| Standard of Ohio | $9.01 | $11.23 | $13.39 | $15.55 | $17.77 | $19.93 |
| Atlantic Richfield | 3:10 | 3.67 | 4.22 | 4.77 | 5.34 | 5.89 |
| Exxon | .77 | .92 | 1.06 | 1.20 | 1.35 | 1.49 |
| Mobil | .38 | .43 | .48 | .54 | .59 | .64 |
| Phillips | .24 | .30 | .36 | .42 | .49 | .55 |

## GROSS PRODUCTION - 1,500,000 b/d (547,500,000 barrels/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| Selling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $[illegible] |
| Unit Profit | .98 | 1.35 | 1.72 | 2.10 | 2.47 | 2.84 |

* * * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio* (38,256,000 shares) | 51.0 | 279.2 | $6.59 | $9.09 | $11.58 | $14.14 | $16.63 | $19.12 |
| Atlantic Richfield (57,834,000 shares) | 19.7 | 107.9 | 1.83 | 2.52 | 3.21 | 3.92 | 4.61 | 5.30 |
| Exxon (225,324,000 shares) | 19.7 | 107.9 | .47 | .65 | .82 | 1.01 | 1.18 | 1.36 |
| Mobil (102,289,000 shares) | 3.3 | 18.1 | .17 | .24 | .30 | .37 | .44 | .50 |
| Phillips (76,113,000 shares) | 2.9 | 15.9 | .20 | .28 | .36 | .44 | .52 | .59 |
| Total Production | 100.0 | 547.5 | | | | | | |

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| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $202.0 | $5.28 | $5.28 | $ 5.28 | $ 5.28 | $ 5.28 | $ 5.28 |
| Atlantic Richfield | 21.00 | 127.3 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 |
| Exxon | 20.00 | 121.2 | .54 | .54 | .54 | .54 | .54 | .54 |
| Mobil | 5.00 | 30.3 | .30 | .30 | .30 | .30 | .30 | .30 |
| Phillips | 1.66 | 10.1 | .13 | .13 | .13 | .13 | .13 | .13 |
| Total | 100.0 | 606.0 | | | | | | |

* * * * * *

| Total Profits | PER SHARE | | | | | |
|---|---|---|---|---|---|---|
| Standard of Ohio* | $11.87 | $14.37 | $16.86 | $19.42 | $21.91 | $24.40 |
| Atlantic Richfield | 4.03 | 4.72 | 5.41 | 6.12 | 6.81 | 7.50 |
| Exxon | 1.01 | 1.19 | 1.36 | 1.55 | 1.72 | 1.90 |
| Mobil | .47 | .54 | .60 | .67 | .74 | .80 |
| Phillips | .33 | .41 | .49 | .57 | .65 | [illegible] |

*Sohio has a 100% net profits interest in the first 600,000 b/d of its net production and a 25% net profits interest in production between 600,000 b/d - 1,050,000 b/d. Assuming Sohio has 51% of the output, 600,000 b/d would be reached at gross production of 1,344,500 b/d. Therefore, Sohio's net per barrel profit will be lower between 1,344,050 and 1,500,000 b/d. The per share earnings figures have been adjusted accordingly.

## GROSS PRODUCTION - 2,000,000 b/d (730,000,000 barrel/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| Selling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Unit Profit | 1.31 | 1.68 | 2.06 | 2.43 | 2.81 | 3.18 |

* * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE |
|---|---|---|---|
| Standard of Ohio<br>(38,256,000 shares) | | | |
| Atlantic Richfield<br>(57,834,000 shares) | | | |
| Exxon<br>(225,324,000 shares) | | | |
| Mobil<br>(102,289,000 shares) | | | |
| Phillips<br>(76,113,000 shares) | | | |
| Total Production | 100.0 | 730.0 | |

Since the Prudhoe Bay Unit is estimated to produce only 1,500,000 b/d this chart cannot be completed.

* * * *

| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $209.0 | $5.46 | $5.46 | $ 5.46 | $ 5.46 | $ 5.46 | $ 5.4 |
| Atlantic Richfield | 21.00 | 131.7 | 2.28 | 2.28 | 2.28 | 2.28 | 2.28 | 2.2 |
| Exxon | 20.00 | 125.4 | .56 | .56 | .56 | .56 | .56 | .5 |
| Mobil | 5.00 | 31.4 | .31 | .31 | .31 | .31 | .31 | .3 |
| Phillips | 1.66 | 10.4 | .14 | .14 | .14 | .14 | .14 | .1 |
| Total | 100,0 | 627.0 | | | | | | |

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| Total Profits | PER SHARE |
|---|---|
| Standard of Ohio | |
| Atlantic Richfield | |
| Exxon | |
| Mobil | [UNCERTAIN] |
| Phillips | |

MEMORANDUM
FROM THE RESEARCH DEPARTMENT

L.F. ROTHSCHILD & CO.
MEMBERS NEW YORK STOCK EXCHANGE, INC

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NEW YORK, NEW YORK 10038
(212) 425-3300
CABLE ADDRESSES: "PROBATICA" OR "ELEFAR"

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December 2, 1975

# THE TRANS-ALASKA PIPELINE AND PRUDHOE BAY CRUDE OIL PRODUCTION ANALYSIS OF UNIT COSTS AND PROFIT POTENTIAL

*(Corrected version - replaces similar memo of November 19, 1975)*

There is considerable investor interest in the cost of building and operating the Trans-Alaska Pipeline, the profit to be derived from the line, and the potential profitability from crude oil production in the Prudhoe Bay Field on the North Slope. In order to provide some perspective on these questions, we have compiled several tables that summarize the latest data on pipeline costs, as well as our estimates of the unit tariff that might be established for transporting crude oil through the pipeline. When combined with the selling prices in Los Angeles, these pipeline estimates should provide an indication of the wellhead value and profit potential for North Slope crude oil production (on the assumption that all oil is tankered to the Los Angeles market). We still expect the pipeline to be completed by late 1976 or the spring of 1977 and think that testing should be completed by the summer of 1977. Initial production should start in 1977, and we expect throughput to reach 1,200,000 b/d in the winter of 1977 - 1978. Profits to the operating companies could be limited in 1977 but should be substantial in 1978. Thus far, 320 miles of the total 800 mile pipeline has been installed. In some weeks, as much as 35 miles of pipe has been laid. Considering the road construction, ditching, vertical supports, and terminal facilities, about 50% of the total construction had been completed as of October 27, 1975.

## UNIT PIPELINE COSTS AND SELLING PRICES

Unit pipeline costs will be importantly influenced by the level of production. Therefore, we have developed cost estimates based on three different production levels; 1,200,000 b/d, 1,500,000 b/d and 2,000,000 b/d. The cost figures used are the latest available official estimates prepared by Alyeska Pipeline, increased by a 5% contingency factor and the cost of additional pumping stations to expand throughput. The pipeline will be a common carrier and should return a good profit to the owners. The current ownership of the Trans Alaska Pipeline is shown on the following page.

IN CONNECTION WITH ARBITRAGE ACTIVITIES L.F. ROTHSCHILD & CO. MAY HAVE EITHER LONG OR SHORT POSITIONS IN SOME OF THE ISSUES MENTIONED IN THIS MEMO AND MAY FROM TIME TO TIME BUY OR SELL SOME OF THE ISSUES MENTIONED.

## OWNERSHIP OF THE TRANS-ALASKA PIPELINE

| Common Share Price 11/26/75 | | % |
|---|---|---|
| 70 | Standard of Ohio | 33.34% |
| 91 | Atlantic Richfield | 21.00 |
| 86 | Exxon | 20.00 |
| 12 | British Petroleum | 15.84 |
| 46 | Mobil | 5.00 |
| 41 | Union | 1.66 |
| 53 | Phillips | 1.66 |
| 15 | Amerada Hess | 1.50 |
| | | 100.00% |

While production volumes and pipeline tariffs lend themselves to reasonably accurate estimates, the question of future crude oil selling prices is more uncertain and, of course, a most important variable. At this time, there is considerable controversy as to where crude oil prices will be in three or four years. Prices on the West Coast will reflect not only the level established by U.S. Government controls but foreign price trends as well. There is a minority viewpoint that foreign oil prices will decline substantially from present levels as a result of sluggish consumer demand and new production coming on from non-OPEC sources. To us, this thesis is hard to accept, and we would be surprised if foreign oil prices dropped sharply from current levels. Landed prices for foreign crude oil on the West Coast are generally in the range of $13.00 - $14.00/barrel exclusive of the present $2.00/barrel supplementary import fee. Domestic crudes have been selling as high as $13.50/barrel but may be rolled back to the area of $11.28/barrel under proposed legislation. In order to cover a broad price range, we are including in our statistical model prices from $8.00 to $13.00/barrel and the estimated profit potential at each level. Our long range thinking is that future price levels in the Los Angeles Basin will be in the general area of $11.00 to $12.00/barrel, and we would key in on the potential profits indicated at these prices.

## PRUDHOE BAY UNIT

It is generally estimated that the Prudhoe Bay Field has recoverable reserves of almost 10.0 billion barrels, which can be produced at a rate of 1,500,000 b/d. Ownership distribution of the Prudhoe Bay Unit (a unitized group of owners of the field) has been under study for almost five years, and a preliminary ownership breakdown should be available in the near future. To arrive at a meaningful judgement of the future earnings potential indicated for each of the major participants in the Unit, we have listed below those companies that have reported North Slope oil reserves and have related these figures to the estimated reserves for the entire field. Thus, we have arrived at the following working estimates of the ownership of production from the Prudhoe Bay Unit. The uncertain nature of the estimates deserves emphasis.

ESTIMATED OWNERSHIP OF THE PRUDHOE BAY FIELD

| | Gross Reserves (Billion Barrels) | % |
|---|---|---|
| Standard of Ohio | 5.100 | 51.0 |
| Atlantic Richfield | 1.970 | 19.7 |
| Exxon | 1.970 | 19.7 |
| Mobil | .325 | 3.3 |
| Phillips | .290 | 2.9 |
| Other * | .345 | 3.4 |
| Total | 10.000 | 100.0 |

*Primarily Amerada Hess, Louisiana Land (23) and Getty (169).

## EARNINGS IMPACT FOR EACH PARTICIPANT

Each member of the Prudhoe Bay Unit will be responsible for the marketing of its gross share of the oil produced. We have made a series of per share earnings estimates for both oil production and ownership of the pipeline based on varying levels of production and selling prices. These estimates are reproduced in the final three tables of this report and should be regarded as a final summary of the numerous variables which have to be reconciled in this exercise.

## SUMMARY

Because of the rising costs of building the pipeline and developing the Prudhoe Bay Field and the changing tax structure for the industry,the initial per barrel cost for North Slope oil has risen sharply over the past few years. Since oil was first discovered on the North Slope, the depletion allowance has been stricken from the federal tax law and the State of Alaska has increased its severance tax to 8%. We would not rule out some further changes in the tax laws. To us,the initial profit potential is far from being a "bonanza" and, if some Washington proponents of a crude oil price rollback are successful, the viability of producing and transporting North Slope oil and gas could be threatened. The same could be said if foreign oil prices drop sharply and bring down the domestic price structure. The latter threat may well be present for some time. We are encouraged that recently proposed legislation makes some allowance for high cost domestic oil such as that from the North Slope. FED Energy Bill

Based on production of 1,500,000 b/d and a selling price of $11.00/barrel, our calculations indicate an annual profit potential of $600 million from the pipeline and $1.2 billion from production, a total return of 18% on the estimated $10 billion initial investment; not a terribly attractive return based on the numerous political and economic risks involved,and well below our earlier estimates.

The final long-term merits of the entire Alaskan project will be importantly influenced by the future returns to be realized from the sale of known natural gas reserves and, of course, additional oil and gas discoveries which should be made on the North Slope. Prospects for the latter appear to be particularly attractive.

ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST

/bjg

| Pipeline Costs: | $ Millions |
|---|---|
| Cost of Construction ($6,375 x 105% *) | 6,700 |
| Capitalized Interest (1974 - 1977) | 1,450 |
| Total | 8,150 |

| Annual Operating Costs: | |
|---|---|
| Pipeline Amortization - $8,150 x 92.5% ** ÷ 35 yrs. | 215 |
| Interest Costs at 10% x (85% of $8,150 million) *(a)* | 693 |
| Operating Costs (Labor, fuel, maintenance, etc.) | 70 |
| Ad Valorem Tax *(b)* | 160 |
| Income Taxes *(c)* | 431 |
| Net Profit - 7% x $8,150 million | 571 |
| Total Annual Costs | 2,140 |

No Separation State w Federal

Pipeline Tariff Per Barrel (438,000,000 bbls./yr.) .. $ 4.89
(Includes a pipeline profit of $1.30)

* *Allowance for contingency.*

** *Assumes 7.5% salvage value.*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production assets.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductable for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

| Per Barrel Profit on Gross Production: | | | | | | |
|---|---|---|---|---|---|---|
| Selling Price (Los Angeles) | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Pipeline Tariff | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 | 4.90 |
| Tanker to L. A. | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 | 5.40 |
| Indicated Wellhead Value | 2.60 | 3.60 | 4.60 | 5.60 | 6.60 | 7.60 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .33 | .45 | .58 | .70 | .83 | .95 |
| Severance Tax (8% of Wellhead Value) | .21 | .29 | .37 | .45 | .53 | .61 |
| Ad Valorem Tax *(a)* | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs | 1.13 | 1.33 | 1.54 | 1.74 | 1.95 | 2.15 |
| Operating Profit | 1.47 | 2.27 | 3.06 | 3.86 | 4.65 | 5.45 |
| Taxes at 53% *(b)* | .78 | 1.20 | 1.62 | 2.05 | 2.46 | 2.89 |
| Net Profit | $ .69 | $1.07 | $1.44 | $1.81 | $2.19 | $2.56 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plus 9.36% state tax (deductible for computing federal taxes).*

| | $ Millions |
|---|---|
| **Pipeline Costs:** | |
| Cost of Construction ($6,700 + $500) | 7,200 |
| Capitalized Interest (1974 - 1977) | 1,450 |
| Total | 8,650 |
| **Annual Operating Costs:** | |
| Pipeline Amortization - $8,650 x 92.5% * ÷ 35 yrs. | 229 |
| Interest Costs @ 10% x (8,650 x 85%) *(a)* | 735 |
| Operating Costs (Labor, fuel, maintenance, etc.) | 70 |
| Ad Valorem Tax *(b)* | 173 |
| Income Taxes *(c)* | 471 |
| Net Profit (7% x $8,650 million) | 606 |
| Total Annual Costs | 2,284 |
| Pipeline Tariff Per Barrel (547,500,000 bbls./yr.)<br>(Includes a pipeline profit of $1.11) | $ 4.17 |

* *Assumes 7.5% salvage value.*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production assets.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductible for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

Per Barrel Profit on Gross Production:

| | | | | | | |
|---|---|---|---|---|---|---|
| Selling Price (Los Angeles) | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Pipeline Tariff | 4.15 | 4.15 | 4.15 | 4.15 | 4.15 | 4.15 |
| Tanker to L. A. | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation | 4.65 | 4.65 | 4.65 | 4.65 | 4.65 | 4.65 |
| Indicated Wellhead Value | 3.35 | 4.35 | 5.35 | 6.35 | 7.35 | 8.35 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .42 | .54 | .67 | .79 | .92 | 1.04 |
| Severance Tax (8% of Wellhead Value) | .26 | .35 | .43 | .51 | .59 | .67 |
| Ad Valorem Tax *(a)* | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs | 1.27 | 1.48 | 1.69 | 1.89 | 2.10 | 2.30 |
| Operating Profit | 2.08 | 2.87 | 3.66 | 4.46 | 5.25 | 6.05 |
| Taxes at 53% *(b)* | 1.10 | 1.52 | 1.94 | 2.36 | 2.78 | 3.21 |
| Net Profit | $ .98 | $1.35 | $1.72 | $2.10 | $2.47 | $2.8 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plus 9.36% state tax (deductible for computing federal taxes).*

# TRANS-ALASKA PIPELINE - 2,000,000 b/d

## Pipeline Costs:

| | $ Millions |
|---|---|
| Cost of Construction ($7,200 + $300) ................ | 7,500 |
| Capitalized Interest (1974 - 1977) .................. | 1,450 |
| Total ............................................... | 8,950 |

## Annual Operating Costs:

| | |
|---|---|
| Pipeline Amortization - $8,950 x 92.5% * ÷ 35 yrs. | 237 |
| Interest Costs @ 10% ($8,950 x 85%) *(a)*.............. | 761 |
| Operating Costs (Labor, fuel, maintenance, etc.) .... | 70 |
| Ad Valorem Tax *(b)* .................................. | 179 |
| Income Taxes *(c)* .................................... | 494 |
| Net Income (7% x $8,950) ............................ | 627 |
| Total Annual Costs .................................. | 2,368 |

Pipeline Tariff Per Barrel (730,000,000 bbls. per yr.) $ 3.24
(Includes a pipeline profit of $.86)

* *Assumes 7.5% salvage value*

(a) *With the commencement of production, substantial sums will be applied to the outstanding loans and interest payments should decline at a significant rate.*

(b) *2% of the assessed value of exploration and production equipment.*

(c) *Effective 53% tax rate is composed of 48% federal tax and 9.36% state tax (deductible for computing federal taxes). We have also allowed for investment tax credits estimated at $500 million and deductible at a rate of $100 million/year for the first five years.*

## Per Barrel Profit on Gross Production:

| | | | | | | |
|---|---|---|---|---|---|---|
| Selling Price (Los Angeles) ............ | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Pipeline Tariff .................... | 3.25 | 3.25 | 3.25 | 3.25 | 3.25 | 3.25 |
| Tanker to L. A. .................... | .50 | .50 | .50 | .50 | .50 | .50 |
| Total Transportation .................. | 3.75 | 3.75 | 3.75 | 3.75 | 3.75 | 3.75 |
| Indicated Wellhead Value ............... | 4.25 | 5.25 | 6.25 | 7.25 | 8.25 | 9.25 |
| Operating Costs | | | | | | |
| Royalty (12.5% of Wellhead Value) | .53 | .66 | .78 | .91 | 1.03 | 1.16 |
| Severance Tax (8% of Wellhead Value) | .34 | .42 | .50 | .58 | .66 | .74 |
| Ad Valorem Tax *(a)* ................. | .09 | .09 | .09 | .09 | .09 | .09 |
| Production Costs ................... | .25 | .25 | .25 | .25 | .25 | .25 |
| Amortization ....................... | .25 | .25 | .25 | .25 | .25 | .25 |
| Total Operating Costs .................. | 1.46 | 1.67 | 1.87 | 2.08 | 2.28 | 2.49 |
| Operating Profit ....................... | 2.79 | 3.58 | 4.38 | 5.17 | 5.97 | 6.76 |
| Taxes at 53% *(b)* ....................... | 1.48 | 1.90 | 2.32 | 2.74 | 3.16 | 3.58 |
| Net Profit ............................. | $1.31 | $1.68 | $2.06 | $2.43 | $2.81 | $3.18 |

(a) *2% of the pipeline's assessed value.*

(b) *Effective 53% rate is composed of 48% federal income tax plus 9.36% state tax (deductible for computing federal taxes).*

## GROSS PRODUCTION - 1,200,000 b/d (438,000,000 barrels/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| Selling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Unit Profit | .69 | 1.07 | 1.44 | 1.81 | 2.19 | 2.56 |

* * * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio (58,502,724 shares) | 51.0 | 223.4 | $2.64 | $4.10 | $ 5.51 | $ 6.93 | $ 8.38 | $ 9.80 |
| Atlantic Richfield (57,834,000 shares) | 19.7 | 86.3 | 1.03 | 1.60 | 2.15 | 2.70 | 3.27 | 3.82 |
| Exxon (225,324,000 shares) | 19.7 | 86.3 | .26 | .41 | .55 | .69 | .84 | .98 |
| Mobil (102,289,000 shares) | 3.3 | 14.5 | .10 | .15 | .20 | .26 | .31 | .36 |
| Phillips (76,113,000 shares) | 2.9 | 12.7 | .12 | .18 | .24 | .30 | .37 | .43 |
| Total Production | 100.0 | 438.0 | | | | | | |

* * * * * *

| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $190.0 | $3.26 | $3.26 | $ 3.26 | $ 3.26 | $ 3.26 | $ 3.26 |
| Atlantic Richfield | 21.00 | 120.0 | 2.07 | 2.07 | 2.07 | 2.07 | 2.07 | 2.07 |
| Exxon | 20.00 | 114.0 | .51 | .51 | .51 | .51 | .51 | .51 |
| Mobil | 5.00 | 29.0 | .28 | .28 | .28 | .28 | .28 | .28 |
| Phillips | 1.66 | 9.5 | .12 | .12 | .12 | .12 | .12 | .12 |
| Total | 100.00 | 571.0 | | | | | | |

* * * * * *

| Total Profits | PER SHARE | | | | | |
|---|---|---|---|---|---|---|
| Standard of Ohio | $5.90 | $ 7.36 | $ 8.77 | $10.19 | $11.64 | $13.06 |
| Atlantic Richfield | 3.10 | 3.67 | 4.22 | 4.77 | 5.34 | 5.89 |
| Exxon | .77 | .92 | 1.06 | 1.20 | 1.35 | 1.49 |
| Mobil | .38 | .43 | .48 | .54 | .59 | .64 |
| Phillips | .24 | .30 | .36 | .42 | .49 | .55 |

## GROSS PRODUCTION - 1,500,000 b/d (547,500,000 barrels/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| elling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Unit Profit | .98 | 1.35 | 1.72 | 2.10 | 2.47 | 2.84 |

* * * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio*<br>(60,928,724 shares) | 51.0 | 279.2<br>(257.5) | $4.15 | $5.72 | $ 7.29 | $ 8.90 | $10.46 | $12.03 |
| Atlantic Richfield<br>(57,834,000 shares) | 19.7 | 107.9 | 1.83 | 2.52 | 3.21 | 3.92 | 4.61 | 5.30 |
| Exxon<br>(225,324,000 shares) | 19.7 | 107.9 | .47 | .65 | .82 | 1.01 | 1.18 | 1.36 |
| Mobil<br>(102,289,000 shares) | 3.3 | 18.1 | .17 | .24 | .30 | .37 | .44 | .50 |
| Phillips<br>(76,113,000 shares) | 2.9 | 15.9 | .20 | .28 | .36 | .44 | .52 | .59 |
| Total Production | 100.0 | 547.5 | | | | | | |

* * * * * *

| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $202.0 | $3.32 | $3.32 | $ 3.32 | $ 3.32 | $ 3.32 | $ 3.32 |
| Atlantic Richfield | 21.00 | 127.3 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 |
| Exxon | 20.00 | 121.2 | .54 | .54 | .54 | .54 | .54 | .54 |
| Mobil | 5.00 | 30.3 | .30 | .30 | .30 | .30 | .30 | .30 |
| Phillips | 1.66 | 10.1 | .13 | .13 | .13 | .13 | .13 | .13 |
| Total | 100.0 | 606.0 | | | | | | |

* * * * *

| Total Profits | PER SHARE | | | | | |
|---|---|---|---|---|---|---|
| Standard of Ohio* | $7.47 | $9.04 | $10.61 | $12.22 | $13.78 | $15.35 |
| Atlantic Richfield | 4.03 | 4.72 | 5.41 | 6.12 | 6.81 | 7.50 |
| Exxon | 1.01 | 1.19 | 1.36 | 1.55 | 1.72 | 1.90 |
| Mobil | .47 | .54 | .60 | .67 | .74 | .80 |
| Phillips | .33 | .41 | .49 | .57 | .65 | .72 |

**Refer to footnote on page 11 for explanation of Sohio's outstanding common shares and per barrel profit potential.*

## GROSS PRODUCTION - 2,000,000 b/d (730,000,000 barrel/year)

| | PER BARREL | | | | | |
|---|---|---|---|---|---|---|
| Selling Price | $8.00 | $9.00 | $10.00 | $11.00 | $12.00 | $13.00 |
| Unit Profit | 1.31 | 1.68 | 2.06 | 2.43 | 2.81 | 3.18 |

* * * * *

| Producing Profits | % | Annual Volume (Mil. Bbls.) | PER SHARE |
|---|---|---|---|
| Standard of Ohio<br>(60,928,724 shares) | | | |
| Atlantic Richfield<br>(57,834,000 shares) | | | |
| Exxon<br>(225,324,000 shares) | | | |
| Mobil<br>(102,289,000 shares) | | | |
| Phillips<br>(76,113,000 shares) | | | |
| Total Production | 100.0 | 730.0 | |

Since the Prudhoe Bay Unit is estimated to produce only 1,500,000 b/d this chart cannot be completed.

* * * * *

| Pipeline Profits | % | Share of Profits (Mil.) | PER SHARE | | | | | |
|---|---|---|---|---|---|---|---|---|
| Standard of Ohio | 33.34 | $209.0 | $5.46 | $5.46 | $ 5.46 | $ 5.46 | $ 5.46 | $ 5.46 |
| Atlantic Richfield | 21.00 | 131.7 | 2.28 | 2.28 | 2.28 | 2.28 | 2.28 | 2.28 |
| Exxon | 20.00 | 125.4 | .56 | .56 | .56 | .56 | .56 | .56 |
| Mobil | 5.00 | 31.4 | .31 | .31 | .31 | .31 | .31 | .31 |
| Phillips | 1.66 | 10.4 | .14 | .14 | .14 | .14 | .14 | .14 |
| Total | 100.0 | 627.0 | | | | | | |

* * * * *

| Total Profits | PER SHARE |
|---|---|
| Standard of Ohio | |
| Atlantic Richfield | |
| Exxon | |
| Mobil | [UNCERTAIN] |
| Phillips | |

## STANDARD OIL OF OHIO

### FULLY DILUTED COMMON SHARES OUTSTANDING BASED ON PRODUCTION LEVELS AT PRUDHOE BAY

| | Prudhoe Bay PRODUCTION | | SOHIO COMMON SHARES | | |
|---|---|---|---|---|---|
| | -- Barrels Per Day -- | | | | |
| | Gross | Sohio Net # | Presently Outstanding | Equivalent Shares Issued to BP | Fully Diluted Total |
| 3/31/75 | -0- | -0- | 27,324,093 | 8,932,000 | 36,551,000** |
| 10/2/75 | -0- | -0- | 29,468,724 | 8,932,000 | 38,613,000** |
| | 448,000 | 200,000 | 29,468,724 | 13,806,000 | 43,274,724 |
| | 560,000 | 250,000 | 29,468,724 | 15,740,000 | 45,208,724 |
| | 672,000 | 300,000 | 29,468,724 | 17,866,000 | 47,334,724 |
| | 784,000 | 350,000 | 29,468,724 | 20,218,000 | 49,686,724 |
| | 896,000 | 400,000 | 29,468,724 | 22,830,000 | 52,298,724 |
| | 1,008,000 | 450,000 | 29,468,724 | 27,894,000 | 57,362,724 |
| | 1,120,000 | 500,000 | 29,468,724 | 29,034,000 | 58,502,724 |
| | 1,232,000 | 550,000 | 29,468,724 | 30,222,000 | 59,690,724 |
| | 1,345,000 | 600,000 | 29,468,724 | 31,460,000 | 60,928,724 |
| | 1,500,000 | 669,375 | 29,468,724 | 31,460,000 | 60,928,724 |

*# 51% of Net Production*
***As reported in October 2, 1975 prospectus.*

**As Sohio's net production rises, the number of shares it will have to issue to BP increases and its net profits interest is adjusted. Sohio has a 100% net profits interest in the first 600,000 b/d of net production and a 25% net profits interest in production between 600,000 b/d and 1,050,000 b/d. After providing for the 12.5% state royalty, we estimate Sohio's 51% share of net production would reach 600,000 b/d at a gross production level of 1,344,500 b/d. Therefore, Sohio's per barrel profit on gross production between 1,344,500 b/d and 1,500,000 b/d would be about 25% of that on gross production at lower levels. The above table lists the additional common shares to be issued to BP as production rises. Also, the per share profit potential for Sohio has been adjusted to reflect both the increased number of shares to be outstanding as well as the reduced per barrel profit figure anticipated after gross production exceeds 1,344,500 b/d.*