

Oil Taxes

General

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AGU 114163

RECOMMENDED CHANGES

IN

ALASKA'S OIL AND GAS PRODUCTION TAX RATES

FOR 1978

A Report to Governor Jay S. Hammond
by the Alaska Department of Revenue

"At the present level of cents-per-barrel rates, the State's production tax income would have to suffer considerable reduction as the result of oil prices artificially lowered below the free-market price before the cents-per-barrel tax would begin working"

--State of Alaska, Department of Revenue,
Alaska's Oil and Gas Tax Structure
(February 1977), p. VI-21

TABLE OF CONTENTS

	PAGE
INTRODUCTION AND BACKGROUND	1
EXPECTATIONS VS FULFILLMENT	6
ELEMENTS AFFECTING VALUE	17
FIELD VALUES	33
INFLATION AND CHANGES IN WORLD OIL PRICES	41
RECOMMENDATIONS	45

INTRODUCTION AND BACKGROUND

Concern over very low wellhead prices for Alaska's nonrenewable oil and gas resources is not a recent development. In 1972, faced with spiralling costs for the Trans Alaska Pipeline and correspondingly, rapidly sinking wellhead values for the oil wealth at Prudhoe Bay, Alaska turned to a cents-per-barrel production tax as a means to protect its revenues from that field, as well as others. By allowing a credit against the cents-per-barrel tax for royalty payments, the net effect of that legislation was to set a floor on the State's combined royalty and tax revenues, regardless how low the wellhead price might have gone. This floor corresponded to the combined revenues that would have been received with a wellhead price of \$2.65 a barrel. The specific cents-per-barrel rates were: 45.8 cents-per-barrel, 51.1 cents-per-barrel, 53.8 cents-per-barrel and 59.1 cents-per-barrel and applied to oil production at specified incremental amounts.

During the First Special Session of 1973, the cents-per-barrel rates were changed, raising the effective floor for production tax income to a level corresponding to a wellhead price of \$3.375 for Prudhoe-type oil (27° API gravity). This floor increased and decreased, depending on whether the API gravity was above or below 27°. In addition the entire cents-per-barrel mechanism was tied to an escalator -- the

Wholesale Price Index for crude oil published by the Bureau of Labor Statistics of the U. S. Department of Labor.

In that 1973 session the cents-per-barrel rates were set at: 16.875 cents-per-barrel for the first 300 barrels of oil production, 20.25 cents-per-barrel for the next 700 barrels, and 27 cents-per-barrel for oil production over 1,000 barrels. These rates corresponded to percentage rates of 5 percent, 6 percent and 8 percent. The continuing concerns over low wellhead prices during 1973 were so strong that the House Finance Committee during the special session went so far as to propose a production tax based solely upon a cents-per-barrel basis with an escalation feature (CS HB4). The major proponent of this approach was the then Speaker of the House of Representatives, Tom Fink. He and others were concerned about the continued reduction of projected Prudhoe Bay wellhead values and the then current price discrepancies in reported royalty and production tax values in Cook Inlet. These price discrepancies were the multiple wellhead values assigned to the oil of the same quality produced in the Cook Inlet area.

After the 1973 change in the production tax statute, several changes occurred in Wholesale Price Index for crude petroleum so that at the beginning of 1977 the basic cents-per-barrel tax rates set out in the statute had escalated to become: 30.51 cents, 36.62 cents and 48.83 cents. At percentage

rates of 5 percent, 6 percent and 8 percent the cents-per-barrel tax set an equivalent cents-per-barrel floor of \$6.10 for 27° crude oil.

In a voluminous review and critique of Alaska's tax laws as applied to the oil and gas industry, the Department of Revenue last year pointed out the following danger in the then-existing production tax:

"... the focus here is on the effectiveness of the tax as a reliable source of revenue for the State and on its safeguards against possible actions that would jeopardize that revenue. The greatest of those dangers is the manipulation of oil price, especially in regard to North Slope oil. There are basically two parties that might want to manipulate the price of Prudhoe oil. One is the oil companies themselves, by inflating transportation costs and similar charges in order to lower the field price of the oil on which the tax is based. The other is the federal government, through price controls.

* * * * *

"The Department of Revenue recommends raising the 'floor' from its present level, which corresponds to \$6.10 a barrel for Prudhoe Bay oil, to a level more

closely reflecting the full market value of that oil. At the present level of cents-per-barrel rates, the State's production tax income would have to suffer considerable reduction as the result of oil prices artificially lowered below the free-market price before cents-per-barrel tax would begin working to prevent any further reduction.

State of Alaska Department of Revenue, Alaska's Oil and Gas Tax Structure (February 1977) pp. V-31 and VI-21 (emphasis added).

Acting on the Department's recommendations, Governor Hammond submitted bills (SB 238 and HB 321) to both Houses that would have raised the cents-per-barrel floor to correspond to a \$7.50 wellhead price, escalating on the basis of the gauge of national inflation (the deflator for the Gross National Product). While many of the production tax proposals in the Governor's bills were eventually enacted, those relating to rates and the cents-per-barrel floor for oil were not. Instead, the version finally passed and presently in effect specifies a 12.25% rate or \$0.80 a barrel for all oil except "old oil", both to be scaled down by the Economic Limit Factor. This sets a cents-per-barrel floor corresponding to a wellhead price of \$6.53 -- higher than the old \$6.10 floor but still almost a dollar below the \$7.50 "full market value" of Prudhoe Bay oil. This floor does not escalate under the new law.

For "old oil" (like the majority of production from Cook Inlet), the cents-per-barrel floor is at a \$5.18 price level (for 34° API gravity).

EXPECTATIONS VS. FULFILLMENT

Federal Pricing Actions.

In its study, Alaska's Oil and Gas Tax Structure (February 1977), the Department of Revenue expressed in some length (at pp. V-37 to V-48) grave concerns about federal intentions and actions and their potential adverse effects on Alaska's price-related revenues from oil and gas, particularly with respect to Prudhoe Bay. By law (15 U.S.C. Sec. 757(g)) North Slope production was (and is) singled out for separate pricing consideration from that of the rest of the country. For reasons set out in that study, the chance that federal price controls could be used to depress the price of Prudhoe Bay crude oil below market levels was a real and ominous possibility.

At hearings before the Federal Energy Administration (FEA) in Washington, D.C. and Anchorage, in March and again in May, the State testified strongly to the need for the marketplace, not price controls, to determine the wellhead price of North Slope oil. In meetings with the Administrator of FEA John O'Leary, and in the White House with James Schlesinger, Governor Hammond brought the State's message home to the federal decision-makers on a personal level.

Fortunately these vigorous efforts were successful.

On August 17, 1977 FEA adopted a rule-making which sets a price ceiling significantly above the anticipated wellhead price level for North Slope oil. At the same time FEA chose to treat North Slope oil the same as high-cost imported oil for purposes of the special "entitlements" program, which is intended to equalize costs between refiners buying less expensive, price-controlled oil and those buying expensive uncontrolled or imported oil. As FEA said at the time,

" . . . by providing [North Slope] crude oil with wellhead prices that are as high as possible (consistent with . . . the cost of the imported oil it is replacing), the maximum monetary and psychological incentives are provided for these and other producers to explore aggressively elsewhere in the Arctic and in other frontier regions."

[Emphasis added]

42 Federal Register 41567 (August 17, 1977).

Actions by the Oil Companies.

Last year the Department of Revenue also expressed concern about actions by the oil companies themselves that would understate the wellhead value of Prudhoe Bay production. As the Department wrote then,

"A [major] vertically integrated company can, in a very real sense, choose which of its integrated operations -- producing, transportation, refining, or marketing -- will be carried on the books as break-even or losing operations and which will be the sources of the profits of the overall enterprise.

". . . Another influence [on where the company books its profits] can be royalty and production tax payments. If the field price of an integrated producer's production can be lowered as the result of shifting booked profits from production to some downstream phase of operations, the overall enterprise would lose nothing by doing so since it is merely moving money from one pocket to another. In fact it would actually have a net gain since the lowered field price means that less royalty and production tax have to be paid

"There seem to be three possible opportunities for some . . . companies owning interests in the Prudhoe Bay field to realize most or all of the benefits from the prevailing prices in the world oil market so dominated by OPEC while holding the line, so to speak, on production tax and royalty for that oil. These are in setting the TAPS tariff (or tariffs), in marine transportation costs and in marketing the oil to refiners outside the West Coast area."

Alaska's Oil and Gas Tax Structure, pp. V-32 and V-33.

The bills submitted by Governor Hammond contained a cents-per-barrel floor corresponding to a wellhead price of \$7.50, which was in accord with the statements of the oil companies themselves and of other experts. The \$6.53 floor in the bill that passed represented an open invitation to the companies to shift profits at least to the extent of the difference between \$7.50 and \$6.53. As we now see from the record, the companies more than accepted that invitation and, in doing so, belied their own statements. It is worth comparing their actions and their words here to reveal the magnitude by which the companies have altered the expectations they led Alaska and others to believe.

In January 1977 -- the month before the Department of Revenue recommended a cents-per-barrel floor of \$7.50 -- Atlantic Richfield Company (ARCO) projected a wellhead price of \$7.58, using a TAPS tariff of \$5.24 and tanker costs from Valdez to the West Coast of \$0.70. ARCO, Crude Oil Postings District V, 1977 Prices, Entitlements Variations (January 3, 1977) cited in University of Alaska Institute of Social and Economic Research, Federal Policies Affecting the Wellhead Value of Prudhoe Bay Crude Oil (March 22, 1977), p. 33.

In a statement presented February 7, 1977 to James R. Schlesinger (then the President's chief energy advisor and now Secretary of Energy), the chairman of the board of The Standard Oil Company (Ohio) Charles E. Spahr said,

"Assuming for a moment that Prudhoe Bay oil sold at the well for the upper tier average price of \$11.63, its delivered price in California would be about \$17.50, including about \$5.00 for the Alaska pipeline tariff and \$.75 for tanker costs from Alaska to California. Obviously, no one would buy Alaskan oil at that price when foreign oil can be purchased at the same place for a little over \$13.00. To be competitive, the wellhead price at Prudhoe Bay would have to go down to something on the order of \$7.25."

On March 9, 1977 FEA issued a "Notice of Inquiry" about the pricing of North Slope oil and announced hearings in Washington, D.C., San Francisco and Anchorage on March 21, 22, and 23, respectively. At those hearings the following testimony was given:

If North Slope crude does not have an entitlement burden and thus is treated . . . like exempt stripper, or Naval Petroleum Reserves oil, we would expect the wellhead price to be about \$7.20 per barrel."

--Herbert H. Zachow, Manager of Crude
and Product Supply, ARCO (March 21, 1977)

"We currently estimate that the TAPS tariff will be approximately \$5.60. This tariff is calculated using traditional ICC methodology."

--Atlantic Richfield Company Responses
To Questions 1 - 14, Alaska North Slope
Crude Oil Pricing and Entitlements
Treatment (March 21, 1977, p.2

"Assuming a \$5.60 tariff and \$.70 vessel cost from Valdez to Los Angeles the following prices would be expected:

TABLE II
ANTICIPATED PRICES

<u>Location</u>	<u>Dec 77</u>	
Wellhead	7.20	. . .
Valdez	12.80	. . .
Puget Sound	13.70	. . .
San Francisco	13.50	. . .
Los Angeles	13.50	. . . "

--Atlantic Richfield Company Responses
to Questions 1 - 14, Alaska North Slope
Crude Oil Pricing and Entitlements
Treatment (March 21, 1977), p. 4

"Until pipelines are in place, the cost to move oil by tanker from Los Angeles to the Gulf Coast through the Panama Canal will be in the range of \$2.00 per barrel."

--Richard M. Donaldson, Vice President
SOHIO (March 23, 1977); also Frank E.
Mosier, Senior Vice President, SOHIO
(March 21, 1977)

"Our expectation is that the TAPS tariff will be in the range of \$5.00 to \$6.00 per barrel from the Prudhoe Bay field to Valdez The costs of tanker movement of the oil from Valdez to Puget Sound, San Francisco, Los Angeles, and the Gulf Coast are expected to average as follows:

Valdez to Puget Sound	\$0.50 per barrel
Valdez to San Francisco	\$0.75 per barrel
Valdez to Long Beach	\$0.75 per barrel
Valdez to Gulf Coast	\$2.75 per barrel"

--SOHIO, Responses to Fourteen Questions
Raised by the Federal Energy Administration
Notice of Inquiry Dated March 7, 1977
 (March 21, 1977), p. 2

"If the present price of oil imported on the West Coast and Gulf Coast is \$13.75 per barrel for quality similar to Alaskan North Slope, then the equivalent prices for North Slope crude are as follows:

	<u>Dollars per Barrel</u>			
	<u>Puget Sound</u>	<u>San Francisco</u>	<u>Los Angeles</u>	<u>Gulf Coast</u>
Delivered	\$13.75	\$13.75	\$13.75	\$13.75
Valdez	\$13.25	\$13.00	\$13.00	\$11.00
Wellhead	\$7.25-\$8.25	\$7.00-\$8.00	\$7.00-\$8.00	\$5.00-\$6.00'

--Sohio, Responses to Fourteen Questions
Raised by the Federal Energy Administration
Notice of Inquiry Dated March 7, 1977
 (March 21, 1977), pp. 6-7

Later, in hearings at Washington, D.C., San Francisco and Anchorage on May 25, 26 and 27, respectively, the oil companies basically repeated these messages to FEA:

"under this rulemaking, a North Slope crude producer will receive about \$7/bbl. at the wellhead for his production."

--Herbert H. Zachow, Vice President, Crude and Product Supply, ARCO (May 25, 1977)

"It is anticipated that when production starts this year, North Slope prices will be entering the market at a wellhead price of around \$7/bbl."

--William E. Wade, Manager of Resources Planning, Corporate Planning Division, ARCO (May 26, 1977)

"With such pricing and entitlement treatment [as ARCO had proposed to FEA in March 1977], we expected North Slope wellhead prices initially to be only about \$7 per barrel. [Actually, ARCO had said \$7.20.] While we continue to favor our recommended pricing and entitlement treatment for North Slope crude, we support the FEA's proposals in the rulemaking under consideration today. These proposals . . . should permit the same initial wellhead price as our earlier recommendations."

--Howard A. Slack, Vice President and Resident Manager, Alaska Division, ARCO (May 27, 1977)

During the question and answer period at the San Francisco hearing, Mr. Wade (quoted above) told Mr. John Muller of FEA that the TAPS tariff was expected to be \$5.50 to \$6.00, and he told Mr. Boldt of FEA that tankers from Valdez to West Coast ports would be \$0.75 to \$0.90. Mr. Steve Donaldson, Manager of Regulatory Reports & Analysis for Powerine Oil Company, disagreed with Mr. Wade's tanker figure, suggesting \$0.45 instead.

This disagreement is nothing compared to the one between the figures quoted above that were given in the first half of last year and the ones the oil companies were reporting for royalty purposes during the second half. The following table summarizes this abrupt change and speaks for itself.

**CONTRADICTIONS
BETWEEN THE OIL COMPANIES' PUBLIC STATEMENTS
AND THE FIGURES THEY REPORTED FOR ROYALTY
PURPOSES TO THE STATE**

(Based on December 1977 reports)

	<u>As Stated</u>	<u>As Reported</u>	<u>Difference</u>
1/3/77, ARCO			
Wellhead Price	\$7.58	\$6.41	(1.71)
TAPS Tariff	5.24	6.15	.91
Tanker to West Coast	.70	.88	.18
2/7/77, SOHIO			
Wellhead Price	7.25	6.14	(1.11)
TAPS Tariff	5.00	6.27	1.27
Tanker to West Coast	.75	.89	.14
3/21/77, ARCO			
Wellhead Price	7.20	6.41	(.79)
TAPS Tariff	5.60	6.15	.55
Tanker to West Coast	.70	.88	.18
3/21 and 23/77, SOHIO			
TAPS Tariff	5.00-6.00	6.25-6.28	0.25-1.28
Tanker to San Francisco or L.A.	.75	.89	.14
Wellhead (net back from San Fran. or L.A.)	7.00-8.00	6.14	(1.86) - (.86)
Tanker to Gulf Coast	2.75	3.61	.86
Wellhead (netback from Gulf Coast)	5.00-6.00	3.53	(2.47) - (1.47)
5/26/77, ARCO			
Wellhead Price	"about 7.00"	6.41	(.59)
TAPS Tariff	5.50-6.00	6.15	.15-.65
Tanker to West Coast	.75-.90	.88	(.02) - .13

For all Prudhoe Bay owners, the weighted average TAPS tariff (based on volume) reported in December was \$6.24 (as opposed to a weighted average tariff based on pipeline ownership percentages, of \$6.20), the weighted average tanker cost reported (based on volume) was \$1.12, and the weighted average wellhead price was only \$5.44. However, the companies did not pay royalties on the basis of that \$5.44; instead, they are claiming further deductions for "field costs," which the State believes are unauthorized. These deductions average 61.4 cents a barrel, reducing the average price actually paid for royalty purposes to \$4.79.

The purpose of mentioning all these prices and deductions is not to set the ground for any possible legislative resolution of these royalty matters, since the royalty questions are already being litigated. Rather, the point to be made is that the industry's interests and those of the State of Alaska do not always coincide; where they do not coincide, the industry has shown that it will readily part company to advance its own purposes. In royalty and in production tax, the industry's interests are served by low wellhead prices and so it has parted company on this matter, not only from the State, but also from its spokesmen who scant months before were unabashedly predicting prices from one to two dollars a barrel higher.

ELEMENTS AFFECTING FIELD VALUE

Earlier in this report it was mentioned generally how the wellhead value of our oil for production tax and royalty is affected by market prices and transportation charges. This section will describe in greater detail how the projected wellhead value of Prudhoe Bay oil has been affected by pricing decisions and transportation charges.

In general, the value of oil for purposes of computing production tax and royalty is determined by taking the market sales price or value for the oil and netting back any transportation charges from the point of sale to the field. Thus the market prices and transportation costs have an important and direct bearing on wellhead values.

Price Ceilings

In the department's oil and gas tax study, possible effects of federal ceilings for North Slope oil were discussed.

Alaska's Oil and Gas Tax Structure (February 1977), pp. V-37 to V-48. At that time the President had not yet recommended to Congress what price ceilings would be applicable to North Slope oil. The danger existed at that time that the federal government could establish a wellhead price ceiling substantially below that of imported crude or even other categories of new oil. That in itself apart from corporate price manipulation

could have substantially reduced severance tax and royalty revenues over time.

Subsequently, however, as stated earlier in this report, the FEA adopted regulations which placed North Slope oil under upper tier price ceilings and gave it exempt entitlement's treatment. 42 Federal Register 41567 (August 17, 1977). This essentially gave favorable pricing and entitlement treatment to North Slope production since the beginning price ceilings would be substantially above what was projected to be a wellhead value for North Slope oil and no entitlement penalties would be assessed against North Slope oil.

Market Prices

The starting point in any determination of wellhead value is market price received for the oil, which is then reduced by the transportation charges between the place of sale and the field where the oil is produced.

In the case of North Slope oil, some oil has been sold right at the mouth of the Trans Alaska Pipeline system (LACT meter) so that no net back of transportation charges is necessary. The market price of that oil in the field, in fact, becomes a value for computation of severance tax purposes assuming that the prices are truly arms-length

sales. Those sales taking place at the wellhead as reported in December Royalty reports are as follows:

<u>Company</u>	<u>Sales Price</u>
Getty	\$6.38
Mobil	6.23

Other companies have made sales at Valdez which include tariff charges on the transportation of the oil from the North Slope to Valdez. These sales are as follows:

<u>Company</u>	<u>Sales Price</u>
Amerada Hess	\$12.60
Exxon	12.30
Hunt Group	12.62
Sohio	12.53

The majority of the oil, however, has been transported by the producing companies and marketed in various locations outside the state. These sales prices and their destinations are:

<u>Company</u>	<u>Sales Price</u>	<u>Destination</u>
ARCO	\$13.44	West Coast
Exxon	13.16	West Coast
Phillips	13.38	West Coast
Sohio	13.30	West Coast
Sohio	13.42	Gulf Coast

Pipeline Tariffs

The largest element of transportation cost, and therefore the one having the biggest effect on wellhead value is the tariff charge of the Trans Alaska Pipeline System (TAPS)

which transports the oil from Prudhoe Bay, where it is produced, to Valdez, where it is loaded onto tankers and transported out of state.

During the months of May and June of 1977 the eight owner companies of the Trans Alaska Pipeline System filed with the Interstate Commerce Commission (ICC) initial tariffs for the transportation of oil from Prudhoe Bay to Valdez. Those initial tariffs ranged from \$6.04 to \$6.44 per barrel and taken together computed a weighted average tariff per barrel of \$6.20 based upon pipeline ownership.

Those initial filed tariffs were:

<u>Pipeline Carrier</u>	<u>Filed Tariff</u>
Amerada Hess	\$6.44
ARCO	6.04
BP	6.35
Exxon	6.27
Mobil	6.31
Phillips	6.22
Sohio	6.16
Union	6.09

Subsequent to the initial filing of pipeline tariffs, the ICC's Bureau of Investigations and Enforcement, the U.S. Department of Justice, the State of Alaska and Arctic Slope Regional Corporation all filed protests against the initial tariffs [Protest and Petitions For Suspension by the United States Department of Justice, June 15, 1977; Protest/Complaint of the State of Alaska Seeking the Suspension and Investigaiton

of Initial Rates and Tariff Provisions, June 15, 1977;
 Protest and Petition of The Bureau of Investigation and
 Enforcement for Suspension and Investigation, June 15, 1977;
 Protest and Petition for Suspension of Initial Rates and
 Tariffs by the Arctic Slope Regional Corporation, June 13, 1977].

The protests sought suspension and institution of a formal
 investigation of the rates published by the TAPS carriers.
 In its protest the State of Alaska set forth what it considered
 reasonable interim tariffs for TAPS as follows:

<u>Pipeline Carrier</u>	<u>Rate</u>
Amerada Hess	(Insufficient information)
ARCO	\$3.74
BP	4.42
Exxon	3.80
Mobil	3.59
Phillips	(Tariff had not been filed)
Sohio	4.04
Union	3.85

Protest/Complaint of the State of Alaska Seeking the Suspension
 and Investigation of Initial Rates and Tariff Provision,
 June 15, 1977 (p. 4).

On June 28, 1977, the Interstate Commerce Commission (ICC)
 suspended the initial filed rates for a seven-month statutory
 period and ordered an immediate investigation of the rates.
 At the same time that the ICC suspended the filed rates it
 stated that it would accept for filing a lower schedule of
 interim rates pending the outcome of the investigation.

That schedule was as follows:

<u>Pipeline Carrier</u>	<u>Interim Rate</u>
Amerada Hess	\$4.85
ARCO	4.91
BP	4.68
Exxon	5.10
Mobil	4.84
Phillips	4.83
Sohio	4.70
Union	4.84

Order of the Interstate Commerce Commission in Investigation and Suspension Docket No. 9164, Trans Alaska Pipeline System (Rate Filings) and No. 36611, Trans Alaska Pipeline System (Rules and Regulations), June 28, 1977.

Thus the initial tariffs, the proposed tariffs by the State of Alaska and the Interim Tariffs allowed by the ICC looked as follows:

<u>Pipeline Carrier</u>	<u>Filed Tariff</u>	<u>Alaska's Proposed Tariff</u>	<u>Interim Tariff</u>
Amerada Hess	\$6.44	--	\$4.85
ARCO	6.04	\$3.74	4.91
BP	6.35	4.42	4.68
Exxon	6.27	3.80	5.10
Mobil	6.31	3.59	4.84
Phillips	6.22	--	4.83
Sohio	6.16	4.04	4.70
Union	6.09	3.83	4.84

Several of the pipeline companies petitioned the Fifth Circuit Court of Appeals contending that the ICC was without authority to suspend the initial tariffs or to suggest maximum interim tariffs. Mobil Alaska Pipeline Company v United States,

No. 77-2392, (July 6, 1977); BP Pipeline Inc. v United States,
No. 77-2412 (July 8, 1977); Exxon Pipeline Co. v United States,
No. 77-2421 (July 11, 1977); ARCO Pipe Line Co. v United States,
No. 77-2437 (July 14, 1977).

The Fifth Circuit Court, however, dismissed the pipeline carriers petitions concluding that the ICC had acted lawfully. Mobil Alaskan Pipeline Company v United States, 557 P2d 775 (1977).

Some of the companies then filed motions in the U.S. Supreme Court for a stay of the Fifth Circuit decision. Four of the carriers also filed petitions for certiorari. The Supreme Court granted a stay of the Fifth Circuit decision and the certiorari petitions, and at the present time a decision on the seven month suspension and interim rates is pending before the Supreme Court. Order of November 28, 1977 Granting Certiorari in Mobil Alaska Pipeline Co. v United States, No. 77-452; Exxon Pipeline Co. v United States, No. 77-457; BP Pipeline, Inc. v United States, No. 77-551; ARCO Pipe Line Co. v United States, No. 602.

Concurrently with the litigation over interim rates the ICC and now its successor the Federal Energy Regulatory Commission (FERC) has been conducting its investigation of TAPS rates in order to set lawful permanent tariffs.

The investigation proceedings have separated into two phases. The first phase of the proceedings deals with such issues as the allowable rate base and the appropriate rate of return while the second phase of the investigation will deal with the amount of costs which may be claimed by the carriers as a part of the rate base.

All of the protestants, including the State of Alaska, argue that the TAPS tariffs filed by the pipeline companies are too high for several reasons. Joint Pre Hearing Brief of the United States Department of Justice, The State of Alaska and The Arctic Slope Regional Corporation, (December 30, 1977).

First, for example, it is being argued that the pipeline companies should earn a rate of return on the actual investment in the pipeline system rather than upon an inflated valuation of replacement cost. This approach would be consistent with rate bases used for most public utilities and would insure that pipeline owners would not receive a return on their investment more than once.

It is also being argued that the rate of return allowed to the pipeline companies on TAPS for the debt and equity portions of the pipeline should be no higher than that needed to reflect the relative risks involved and to compensate for the costs of servicing the debt.

In addition, the protestants have argued that the pipeline owners should be allowed only a return on prudent investments and not be allowed to include any costs due to mismanagement or inefficiency.

All of the arguments are aimed at the extremely excessive nature of the tariffs. One illustration of how the tariffs were "pumped-up" as high as they were is shown by the double counting of a rate of return on the pipeline owners debt. In the initial filing, the pipeline carriers computed their proposed tariffs high enough to cover their operating costs (including interest) plus a rate of return on the total valuation of the pipeline. In essence, the pipeline companies were claiming a double rate of return on that portion of the pipeline financed through debt. They were first recovering their interest expense on their debt in addition to a rate of return on the borrowed money itself. The ICC, however, - in its order suspending the rates, eliminated the double counting for purposes of setting interim rates by specifying that it would accept, on an interim basis, tariffs based upon a 10 percent rate of return on valuation with interest cost to be paid out of company's rate of return.

The effect of the excessive tariffs for the pipeline companies was extremely high rates of return and substantial profits for the pipeline companies. For example the degree of profit that would be yielded by the pipeline companies using

their originally filed tariffs was illustrated by the Commission as follows:

<u>Pipeline Carrier</u>	<u>on Equity</u>	<u>on Total Investment</u>	<u>on Valuation</u>
Amerada Hess	31.5%	13.8%	13.3%
ARCO	86.2%	13.1%	12.4%
BP	42.5%	14.2%	13.5%
Exxon	31.4%	13.2%	12.5%
Mobil	(no equity)	13.8%	13.1%
Phillips	38.2%	14.0%	13.1%
Sohio	40.6%	13.6%	13.1%
Union	71.1%	13.8%	12.7%
Average	46.0%	13.6%	12.9%

These inflated tariffs substantially reduced severance tax and royalty values and resulted in considerably reduced revenues. For example, shortly after the initial tariffs were filed the Department of Revenue estimated the loss of revenues would be as shown in the following table:

<u>Duration of High Tariffs</u>	<u>Reduced Royalty and Prod. Tax Revenue</u>
6 months	15.6
12 months	41.7
18 months	70.5

These initial tariffs were way beyond what others expected the pipeline companies would claim. Those third party estimates are shown on the following table.

<u>Date</u>	<u>Source</u>	<u>Amount</u>
11/76	Mortada International, <u>The Determination of Equitable Pricing Levels for North Slope Alaskan Crude</u> , pp. II-18, III-10, III-12, IV-24, VII-6 VII-7	4.20-4.50
4/76	Drexel Burnham & Co., <u>The North Slope: Paradise Lost?</u> pp. IV-11	4.60
1/7/77	Washington Analysis Corp., <u>Entitlements Program Impact on North Slope Profits</u>	5.00
2/28/77	Merrill, Lynch, Pierce, Fenner & Smith, Inc., <u>Institutional Report "Petroleum Notes, Prudhoe Bay Crude Oil, Entitlements Program</u> , p. 4	5.40
4/1/77	Wainright Securities Inc., <u>Industry Review, "Petroleum Industry, North Slope Oil and Gas,"</u> pp. 25 (Table 7), 43 (Table 10).	4.28*
	*includes 5¢ for TAPS liability fund	
4/15/77	The President of the United States, <u>Report to Congress on the Pricing of Alaska North Slope (ANS) Crude Oil</u> , pp. 63-64 (Table IX-3).	5.10

Even the Department of Revenue's extremely conservative estimate of \$5.54 (worst case scenario) of what the companies might claim fell substantially below what was actually filed. As shown earlier in this report the filed tariffs also exceeded substantially the public pronouncements of the companies themselves.

Tanker Tariffs

Another item having a direct impact on the wellhead value for calculation of the severance tax is the cost of marine transportation from Valdez to various points on the West Coast and Gulf Coast of the United States.

Unlike pipeline tariffs, the oil tanker transportation costs are not regulated by any government regulatory body since the tankers are not operating as common carriers. Instead the transportation charges are set by negotiation between the tanker company and the shipper, which in some cases may be between affiliated companies.

Since production began in June of 1977 tankers have been loading oil at Valdez and transporting it to various locations in the states of California, Washington and on the Gulf of Mexico. The charges claimed for this transportation have varied considerably between shippers and far exceed the expectation of third parties who estimated the amount of the charge.

Those tanker charges that have been claimed during the month of December are as follows:

<u>Company</u>	<u>Charge</u>	<u>Destination</u>
ARCO	\$.88	West Coast
Exxon	1.08	West Coast
Phillips	.81	West Coast
Sohio	.89	West Coast
Sohio	3.61	Gulf Coast

These tanker charges that have ranged from \$.88 to \$3.61 are substantially greater than what other third parties thought the charges would be. These estimates were as follows:

<u>Date</u>	<u>Source</u>	<u>Tanker Cost</u>
11/76	Mortada International, <u>The Determination of Equitable Pricing Levels for North Slope Alaskan Crude</u> , pp. II-13, III-10, III-12, IV-24, VII-6 and VII-7	
	Delivered to Los Angeles	.671*
	Delivered to Puget Sound	.459*
	*Figures in 1976 dollars	
4/76	Drexel Burnham & Co., <u>The North Slope: Paradise Lost?</u> , pp. IV-11	.50
1/7/77	Washington Analysis Corp., <u>Entitlements Program Impact on North Slope Profits</u>	
	Delivered to West Coast	.60
2/28/77	Merrill, Lynch, Pierce, Fenner & Smith, Inc., <u>Institutional Report, "Petroleum Notes, Prudhoe Bay Crude Oil, Entitlements Program,"</u> p. 4.	.55
4/1/77	Wainwright Securities Inc., <u>Industry Review, "Petroleum Industry, North Slope Oil and Gas,"</u> pp. 25 (Table 7), 43 (Table 10)	
	Delivered to Puget Sound	.50
	Delivered to San Francisco	.80
	Delivered to Long Beach	.70
	Delivered to Houston	2.45
4/15/77	The President of the United States, <u>Report to Congress on the Pricing of Alaska North Slope (ANS) Crude Oil</u> pp. 63-64 (Table IX-3)	
	Delivered to Puget Sound (120 MB/D)	.74
	Delivered to San Francisco (250 MB/D)	.96
	Delivered to Los Angeles (340 MB/D)	1.01
	Delivered to Gulf Coast (490 MB/D)	2.98

The Department of Revenue predicted a weighted average tanker charge of \$.59 to the West Coast and it too was much below the tanker charges claimed.

Transportation to more Distant Markets

Another factor complicating the determination of wellhead value is the West Coast surplus. When the new production from Prudhoe Bay combined with imports and California production, the amount of crude oil exceeded the physical capacity of the refineries on the West Coast to process it. As a result the surplus oil had to be, and still must be transported to other areas of the United States in order to be sold.

Currently, the North Slope surplus oil is being transported by Sohio through the Panama Canal by tanker to market destinations on the Gulf Coast. As production from Prudhoe Bay increases to 1.2 million barrels a day in March of this year, the surplus situation will worsen.

Several possible pipelines to transport surplus oil from the West Coast to eastern markets are on the drawing board, including: The Sohio Pipeline, Atlantic Richfield's proposed "Yoyo" of the Trans-Mountain line, the Kitimat line and the Northern Tier Pipeline. For the short term, however, no relief from the problem is in sight except the costly transshipment through the Panama Canal.

The extra transportation charge claimed by Sohio for shipment through the Panama Canal has been \$2.72 per barrel. This in

itself has greatly reduced the wellhead value on a major portion of the North Slope production.

FIELD VALUE

In taking the market prices received for Prudhoe Bay oil and netting back actual claimed transportation charges from the point of sale to the point of production, the producers are reporting wellhead values ranging from \$3.53 to \$7.70.

The lowest value is reported by Sohio for the oil which it is marketing on the Gulf Coast. Sohio begins with a market price on the Gulf Coast of \$13.42. From that amount it is deducting \$3.61 for tanker transportation from Valdez to the Gulf Coast and a \$6.28 TAPS pipeline charge from Prudhoe Bay to Valdez.

A schedule showing the various reported values for each of the producers follows. These reported values are taken from the December royalty reports as filed by the North Slope producers, and as stated earlier these values taken together produce a weighted average wellhead value for severance tax purposes of \$5.44.

Producer	Quantity	Sale	Market Price	Tanker Cost	TAPS Tariff	Reported Value*
Amerada Hess	119,585	Valdez	\$12.60	--	\$6.44	\$6.16
ARCO	4,507,962	West Coast	13.44	.88	6.16	6.40
Chevron	187,488	--	--	--	--	7.70
EXXON	3,913,000	West Coast	13.16	1.08	6.27	5.81
EXXON	514,699	Valdez	12.30	.15	6.27	5.88
EXXON	41,736	Fairbanks	12.30	--	6.274	6.026
Getty	121,920	Prudhoe Bay	6.38	--	--	6.38
Hunt Group	21,191	Valdez	12.62	--	6.14	6.48
Louisiana Land & Expl.	8,839	Valdez	11.89	--	6.04	5.85
Marathon	11,094	--	--	--	--	6.35
Mobil	465,495	Prudhoe Bay	6.23	--	--	6.23
Phillips	454,632	West Coast	13.38	.81	6.22	6.35
Placid	9,415	Valdez	12.62	--	6.14	6.48
Sohio	4,550,000	West Coast	13.30	.89	6.27	6.14
Sohio	6,097,000	Gulf Coast	13.42	3.61	6.28	3.53
Sohio	1,170,000	Valdez	12.53	--	6.25	6.28

*Not including field cost deductions

Although clearly not deductible under AS 43.55.140 for severance tax purposes in determining wellhead value, the producers have deducted so called "field costs" in determining wellhead value for royalty payments. These costs or deductions represent the costs of gathering, cleaning and dehydrating the oil from the point where the oil comes out of the ground to the point where it is metered into the Trans Alaska Pipeline. The state has taken issue with these deductions as well as all other producer calculations of wellhead value for royalty purposes in a lawsuit entitled State v Amerada Hess et. al., Superior Ct., No. 77-847, First Judicial District.

The amount of field costs deducted for royalty purposes have varied in amount among the producers and for December those deductions ranged as follows:

<u>Producer</u>	<u>Field Cost Deductions</u>
Amerada Hess	.68
ARCO	.64
Exxon	.53
Getty	.78
Mobil	1.11
Phillips	1.03
Placid	.77
Sohio	.60

Thus for royalty purposes the producers during the month of December reported values as follows:

<u>Producer</u>	<u>Royalty Value</u>
Amerada Hess	\$5.48
ARCO	5.77
Chevron	7.70
Exxon (West Coast)	5.28
Exxon (Valdez)	5.35
Exxon (Fairbanks)	5.50
Getty	5.60
Hunt Group	6.48
Louisiana Land & Exploration	5.85
Marathon	6.35
Mobil	5.12
Phillips	5.32
Placid	5.71
Sohio (West Coast)	5.48
Sohio (Gulf Coast)	2.87
Sohio (Valdez)	5.62

Thus with claimed field costs, Sohio for example, is claiming a wellhead value of \$2.87 for the oil which it is shipping to the Gulf Coast. The weighted average wellhead value of Prudhoe Bay oil for royalty purposes for all producers during the month of December is \$4.79 per barrel.

In contrast to the values being reported to the State of Alaska for severance tax and royalty purposes, an objective comparison of the value of North Slope oil using comparable market refining prices on the West Coast and reasonable transportation charges from the market to the North Slope oil field yields a value substantially above the reported values.

First of all, in computing a comparative market wellhead value, we begin with a free market price of oil of like quality to that of North Slope oil. That market price of oil, most comparable to North Slope oil is the price of oil imported to the West Coast and is computed as follows.

VALUE OF 27° ALASKA NORTH SLOPE (ANS) OIL
AT REFINERY DESTINATION

	<u>Los Angeles</u>
Saudi sales price FOB Ras Tanura	\$12.32
Class 2 tanker tariff (AFRA)	1.12
Import fee	-0-
Price for Saudi FOB refinery	13.44
Entitlement for Saudi	-2.37
Refiner's acquisition cost for Saudi	11.07
Entitlement given for ANS oil	2.37
VALUE (Max. price refiners would pay for ANS oil)	13.44

Thus the free market value at the refinery of Prudhoe Bay oil is \$13.44.

Secondly, reasonable transportation charges need to be computed and subtracted from the market price at the refinery. Again we have used third party bench marks in computing a comparison of wellhead value.

All the TAPS protestants including the State of Alaska, the U.S. Justice Department, the Arctic Slope Native Corporation, and the ICC staff have recommended TAPS tariffs substantially below what the companies originally filed. All of the TAPS

protestants except the ICC staff recommended TAPS tariffs below even the ICC interim tariffs. For purposes of this report, however, we have chosen the ICC interim rates as a bench mark for reasonable pipeline transportation costs even though these tariffs may in fact still be too high as permanent tariffs.

Those interim tariffs were:

<u>Pipeline Carrier</u>	<u>Interim Rate</u>
Amerada Hess	4.85
ARCO	4.91
BP	4.68
Exxon	5.10
Mobil	4.84
Phillips	4.83
Sohio	4.70
Union	4.84

Using the weighted average of these tariffs results in a pipeline transportation cost of \$4.83 per barrel.

For tanker transportation to the West Coast we have chosen a conservative estimate of .70 based upon third party calculations of average tanker costs to the West Coast.

Using these third party bench mark figures of refinery prices and transportation costs results in a market price net back to the field of \$7.91.

Also in contrast to the reported wellhead values are the projections of values by third parties as shown in the following table. Interestingly enough, however, these third party estimates coincide closely with our construction of an objective determination of a Prudhoe Bay wellhead value.

<u>Date</u>	<u>Source</u>	<u>Delivered Price</u>	<u>Tanker</u>	<u>TAPS Tariff</u>	<u>Wellhead Price</u>
4/76	Drexel Burnham & Co., <u>The North Slope: Paradise Lost?</u> pp. IV-11	13.00	.50	4.60	7.90
11/76	Mortada International, <u>The Determination of Equitable Pricing Levels for North Slope Alaskan Crude</u> , pp. II-18 III-10, III-12, IV-24, VII-6 and VII-7				
	Delivered to Los Angeles	13.05*	0.671*	4.20-4.50	7.88-8.18
	Delivered to Puget Sound		0.459*	4.20-4.50*	
	Average Case				7.90*
	*Figures in 1976 dollars.				
1/7/77	Washington Analysis Corp., <u>Entitlements Program Impact on North Slope Profits</u>				
	Delivered to West Coast	13.52	0.60	5.00	7.92
2/28/77	Merrill, Lynch, Pierce, Fenner & Smith, Inc., <u>Institutional Report, "Petroleum Notes, Prudhoe Bay Crude Oil, Entitlements Program,"</u> p.4				
	Delivered to West Coast	13.40	0.55	5.40	7.45
4/1/77	Wainwright Securities, Inc., <u>Industry Review, "Petroleum Industry, North Slope Oil and Gas,"</u> pp. 25 (Table 7), 43 (Table 10)				-
	Delivered to Puget Sound	13.27	0.50	4.28*	8.49
	Delivered to San Francisco	13.38	0.80	4.28*	8.30
	Delivered to Long Beach	13.32	0.70	4.28*	8.34
	Delivered to Houston	13.57	2.45	4.28*	6.84
	*includes 5¢ for TAPS liability fund				
4/15/77	The President of the United States, <u>Report to Congress on the Pricing of Alaska North Slope (ANS) Crude Oil</u> , pp. 63-64 (Table IX-3)				
	Delivered to Puget Sound (120 MB/D)	14.53	0.74	5.10	8.69
	Delivered to San Francisco (250 MB/D)	14.53	0.96	5.10	8.47
	Delivered to Los Angeles (340 MB/D)	14.53	1.01	5.10	8.42
	Delivered to Gulf Coast (490 MB/D)	14.83	2.98	5.10	6.75
	Weighted Average	---	--	--	7.77

INFLATION AND CHANGES IN WORLD OIL PRICES

In Alaska's Oil and Gas Tax Structure (p. VI-22), the Department of Revenue recommended last year that

"[t]o prevent the 'floor' from losing value through time it should escalate"

Suggested escalators then were the Gross National Product (GNP) deflator, which is the primary index of U.S. inflation, and the world market price of similar foreign oil. The GNP deflator during the last year has changed as follows:

GNP Deflator (1972 = 100)		
<u>Index Period</u>	<u>Index Amount</u>	<u>Change from 3rd Quarter 1976</u>
3rd Quarter 1976	134.56	--
4th Quarter 1976	136.35	+1.3%
1st Quarter 1977	138.13	+2.7%
2nd Quarter 1977	140.52	+4.4%
3rd Quarter 1977	142.25	+5.7%

With respect to world oil market prices, 1977 saw a period of two-tier pricing within OPEC come to an end. The split in OPEC developed when Saudi Arabia and the United Arab Emirates (UAE) refused to go along with the rest of OPEC in December 1976 in raising their State Sales Prices by 10 percent. Instead, Saudi Arabia and the UAE raised prices by only about 5 percent. In midyear this breach was closed, when the two nations raised their prices while the rest of OPEC forewent its previously announced increase scheduled

for that time. Since Saudi Arabian crudes are of all imports, most like Prudhoe Bay crude in refining characteristics, the midyear increase in price for those crudes is relevant to the appropriate cents-per-barrel floor for Alaskan oil production. Accordingly, the exact prices and percentages of change follow:

Changes in State Sales Prices (FOB)
by Saudi Arabia and the U.A.E.
During 1977

<u>Crude Type</u>	<u>1-1-77</u> \$/B	<u>1-9-78</u> \$/B	<u>%</u> <u>Change</u>	
Saudi Arabia				
Berri (39°)	12.48	13.22	+5.9]	+5.5% average
Light (34°)	12.09	12.70	+5.0]	
Medium (31°)	11.69	12.32	+5.4]	
Heavy (27°)	11.37	12.02	+5.7]	
U.A.E. (39°)	12.514	13.26	+6.0	

Source: Platt's OILGRAM Price Service

Besides these indicators, other indices are available and could be used. For example, a Consumer Price Index is calculated for the entire United States, and another one for Anchorage. Their changes are given below.

Changes in Consumer Prices Indices
for the United States and for Anchorage

<u>Index</u> <u>Month</u>	<u>Anchorage Index</u>		<u>United States Index</u>	
	<u>Index Amount</u> <u>(1967 = 100)</u>	<u>% Change</u> <u>from 10/76</u>	<u>Index Amount</u> <u>(1967 = 100)</u>	<u>% Change</u> <u>from 10/76</u>
Oct. '76	167.6	--	173.3	--
Jan. '77	169.4	+1.1	175.3	+1.2
Apr. '77	172.6	+3.0	179.6	+3.6
Jul. '77	177.4	+5.8	182.6	+5.4
Oct. '77	177.3	+5.8	184.5	+6.5

The table on the following page provides a comparison of U.S. price indices for crude petroleum and refined petroleum products, which the Bureau of Labor Statistics of the U.S. Department of Labor prepares and maintains.

**A Comparison of U.S. Price Indices for Crude Petroleum
and Petroleum Refined Products, December 1976 and
December 1977 (1967 = 100 unless otherwise indicated)**

	<u>Index</u> <u>12-76</u>	<u>Index</u> <u>12-77</u>	<u>%</u> <u>Change</u>
Crude Petroleum	264.4	288.1	8.96
Petroleum Products, Refined	287.6	313.7	9.08
Gasoline	263.4	279.5	6.11
REGULAR	242.2	255.8	5.62*
Dealer Tank-wagon to Retail Outlets	225.8	238.6	5.67*
Sales to Jobbers	267.1	283.3	6.07*
Commercial Consumers	256.4	267.9	4.49*
PREMIUM	214.9	229.8	6.98*
Dealer tank-wagon to Retail Outlets	204.9	218.7	6.73*
Sales to Jobbers	237.1	254.9	7.51*
Commercial Consumers	242.3	260.0	7.30*
UNLEADED	100.0	99.7	-.3
Dealer tank-wagon to Retail Outlets	100.0	99.9	-.1*
Sales to Jobbers	100.0	99.6	-.4*
Commercial Consumers	100.0	98.6	-1.4*
Light Distillate	323.2	381.2	17.95
Kerosene to Resellers	266.1	303.7	14.13*
Commercial Jet Fuel, Kerosene base	269.9	320.0	18.96*
Middle Distillate	349.8	394.2	12.69
Fuel Oil No. 2 to Resellers	282.0	319.9	13.44*
Diesel to Commercial Consumers	281.6	314.2	11.58*
Residual Fuels	480.4	510.5	6.27
Cargo shipments to Resellers	305.6	328.3	7.43*
Steam Electric Utilities	100.0	103.4	3.40*
Lubricating Oil Materials	274.3	333.4	21.55
Bright Stock	169.5	203.6	20.11*
Neutral Stock	152.6	192.8	26.34*
Pale Stock	98.0	115.8	18.16*
Finished Lubricants	178.6	197.5	10.58
Automotive Motor Oils	156.5	170.8	9.14
Industrial Oils	167.7	190.9	13.83*
Petroleum Grease	126.5	130.2	2.92*
Petroleum Wax	200.2	247.5	23.63

Source: U.S. Department of Labor
Bureau of Labor Statistics

*base year different than 1967

RECOMMENDATIONS

The present \$6.53 floor for "other oil" is inadequate.

As shown earlier (p. 38) an objective computation of the market value of Prudhoe Bay oil using comparable refinery market prices and reasonable transportation costs (determined from third party sources) yields a wellhead value of \$7.91.

Additionally, at the same time as the Department recommended a \$7.50 floor, the oil companies were speaking publicly of wellhead prices near and above that level. Numerous informed consulting firms were forecasting prices in this range, too (see p. 40). Aside from inflation and the price increases of Saudi Arabia and the UAE, nothing else has changed during 1977 that would alter the appropriateness of that figure. As such, \$7.50 plus 5.7 inflation as measured by the G.N.P. deflator yeilds a value of \$7.93.

Accordingly, the Department of Revenue recommends a floor of \$7.90. The cents-per-barrel amount that corresponds to this floor at a 12.25 percent rate is .96775 which, when rounded, is \$.968. AS 43.55.011(c) should be amended so that \$.968 replaces the \$.80 figure that is there now.

The Department also believes it is appropriate at this time to adjust the cents-per-barrel rate for "old oil" and the cents-per-Mcf rate only to the extent necessary to offset

the 5.7 percent inflation. Thus the \$0.60 figure in AS 43.55.011(c) should be changed to \$0.634, and the \$0.064 figure in AS 43.55.016(c) should be changed to \$0.068.

While AS 43.55.012(a) requires only that Department of Revenue make the recommendations above, the Department will further recommend a change in AS 43.55.012(a) itself so that a greater degree of stability may be incorporated into the production tax. As that statute reads now, the cents-per-barrel tax rates must come under review each and every year. This needlessly creates an uncertainty from one year to the next, which can eventually harm the investment climate for further oil and gas development.. The Department therefore recommends tying the cents-per-barrel and cents-per-Mcf rates to an index to offset the adverse effects of inflation on the meaningfulness of these floors. This would be done by repealing AS 43.55.012(a) in its entirety and enacting the following provision to replace it:

(a) The amounts set out in sec. 11(c) and sec. 16(c) of this chapter shall be increased or decreased by a percentage equal to the percentage of change in the Gross National Product Deflator published by the Bureau of Economic Analysis of the United States Department of Commerce, using 1972 as the base period for the deflator (1972 = 100). Changes in tax rates will be computed based on changes in the Gross National

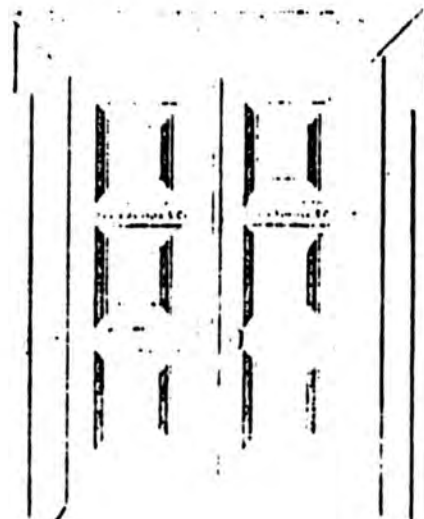
Product Deflator from the First Quarter 1978 Gross National Product Deflator. The department shall post the changes in the tax rates periodically and shall notify every person producing oil within the state of the changes.

FILE COPY

Prudhoe Bay Field
And
Trans-Alaska Pipeline System

COMPARATIVE STATE TAX
BURDEN STUDY

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ARTHUR ANDERSEN & Co.
FEBRUARY, 1979

TABLE OF CONTENTS

	<u>Page</u>
TRANSMITTAL LETTER	
INTRODUCTION AND PURPOSE OF STUDY:	
Period of Study	1
General Approach to Study	2
Sources of Information	3
ASSUMPTIONS EMPLOYED IN STUDY:	
Scope of the Study	5
Discussion with Industry and Others	6
Tariff Rate	6
Wellhead Value	8
Royalty Payments	9
Royalty Report	9
Book/Tax Timing Differences	9
Average Life Method	9
Unit Appraisal Method	10
Depreciation	11
FINDINGS	12
DISCUSSION:	
Ad Valorem Taxes	15
Alaska	15
California	16
Kansas	18
Louisiana	20
New Mexico	20
Oklahoma	22
Texas	22
Wyoming	26
Severance Tax	27
Alaska	27
California	28
Kansas	28
Louisiana	28
New Mexico	28
Oklahoma	29
Texas	29
Wyoming	30
Income Tax	30
General Discussion	30
Alaska	33
California	34
Kansas	34
Louisiana	35
New Mexico	35
Oklahoma	36
Texas and Wyoming	36

	<u>Page</u>
Franchise Tax	
Alaska	37
California	37
Kansas	37
Louisiana	37
New Mexico	37
Oklahoma	38
Texas	38
Wyoming	39
Sales and Use Tax	39
Miscellaneous Taxes	40

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February 23, 1979

To Members of the Alaska Oil and Gas Association:

We are pleased to submit to you the updated Comparative State Tax Burden Study of Prudhoe Bay Field production and the Trans-Alaska Pipeline System (TAPS). Consistent with the 1978 report, the study shows that the tax burden on oil and gas production in Alaska is significantly higher than in other states. The study also shows that the tax burden on TAPS is significantly higher than in other states.

The study was prepared by Arthur Andersen & Co. and is being submitted to you for your information and use.

The study was prepared by Arthur Andersen & Co. and is being submitted to you for your information and use. The study shows that the tax burden on oil and gas production in Alaska is significantly higher than in other states. The study also shows that the tax burden on TAPS is significantly higher than in other states.

The results of the study show that within the constraints of the assumptions in both the inflated and noninflated alternatives, the tax burden on oil and gas production in Alaska is significantly higher than in other states. The margin by which the State of Alaska's tax burden exceeds the other states in the study is substantially greater than in the 1978 report.

We appreciate this opportunity to have been of continuing service to you in this engagement.

Very truly yours,

Arthur Andersen & Co.

COMPARATIVE STATE TAX BURDEN

INTRODUCTION AND PURPOSE OF STUDY

The purpose of this study is to compare the state tax burden on the Prudhoe Bay oil production facilities, Sadlerochit oil pool reserves and the Trans-Alaska Pipeline System (TAPS) under existing Alaska laws compared to what the tax would be if Alaska adopted the laws of California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, or Wyoming.

The [REDACTED]

[REDACTED] To best accomplish the comparison, [REDACTED] the four major owners of TAPS and the three largest percentage owners of Prudhoe Bay Sadlerochit oil pool reserves. These companies are the following: Atlantic Richfield Company [REDACTED] BP Pipelines, Inc. [REDACTED], Exxon Corporation [REDACTED] and The Standard Oil Company, an Ohio corporation [REDACTED] (See Exhibit I for ownership percentages.)

Period of Study-

The study compares the relative tax burdens of the eight states [REDACTED] The study summarizes, in total, the taxes for 25 years of operation of TAPS and of production from Prudhoe Bay Sadlerochit oil pool. Because known recoverable reserves in the Sadlerochit oil pool are expected to be substantially

depleted in terms of economic recovery in 25 years,¹ taxes have not been calculated on production from the 26th through the 32nd year although such period was considered by Pritchard & Abbott.²

General Approach to Study-

The study is performed under the following two alternatives:

In the first alternative, the total taxes are calculated based on noninflated public data. A constant price of \$13.30 per barrel is assumed for crude oil.³ Operating expenses and future capital expenditures of Prudhoe Bay production facilities, obtained from Pritchard & Abbott, are stated in terms of 1977 dollars. Operating expenses of TAPS are obtained from the ICC Order.⁴

The second alternative considers the effect of inflation on the relative positions of the various states in the study. Pritchard & Abbott's valuation of Prudhoe Bay Sadlerochit Pool Unit Area adjusted to reflect inflation is the primary source of data. Pritchard & Abbott inflates the price of oil until 1982 and then holds the price constant over the remaining life of production. Capital and operating expenditures are inflated seven percent and nine percent, respectively, until 1982 only. No inflation has been considered for years after 1982.

¹ Investigation and Suspension Docket No. 9164, (Interstate Commerce Commission, June 22, 1977), p. 5.

² Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area (Pritchard & Abbott, 1977).

³ Royalty Reports to State of Alaska (Major field owners except Exxon, June, 1977; Exxon, July, 1977).

⁴ Supra. Note 1.

Sources of Information-

The study uses data obtained from the Order of the Interstate Commerce Commission (ICC) dated June 28, 1977, authorizing interim rates by the TAPS owners for calculation of expenses attributable to TAPS operations. In addition, the study utilizes this identical order as a means of valuation of the pipeline for calculation of ad valorem taxes in those states practicing a unit appraisal or economic approach to valuing property.

For estimating the future production from Prudhoe Bay oil reserves and estimating the valuation of the Prudhoe Bay production facilities, reliance is placed on data obtained from the Pritchard & Abbott report. Inquiry of interested parties has determined that no more accurate and reliable public information than the Pritchard & Abbott report utilized in the 1978 report has become available for estimation of future revenue and costs of Sadlerochit oil pool. In addition, since testimony on the TAPS tariff rate issue is currently before the Federal Energy Regulatory Commission with final settlement and adjudication requiring some, as of yet unascertainable, additional time, reliance has again been placed on the ICC Order as the best available public source of the estimated future revenue and costs of TAPS.

For purposes of the franchise tax, Form 12-K and Form P are used to determine the total capital and retained earnings of the owners' subsidiary pipeline companies. For calculation of franchise tax for Prudhoe Bay operations, capital and retained earnings of

Exxon parent is obtained from Exxon's Form 10-K. For calculation of franchise tax for Prudhoe Bay operations of ARCO and SOHIO, information of a proprietary nature (nonpublic information) has been obtained from the individual companies.

Nonpublic information has also been furnished by each owner company with respect to its sales, property, and payroll, both within and outside Alaska.

ASSUMPTIONS EMPLOYED IN STUDY

Scope of the Study-

For purposes of the 1978 and 1979 reports, the study is limited to a comparison of only those taxes attributable to the Prudhoe Bay oil production facilities, Sadlerochit oil pool reserves and TAPS. The tax liability arising from gas production from Prudhoe Bay and other producing areas, and oil and/or gas production from Cook Inlet have not been calculated.

Even though gas production from Prudhoe Bay was considered at the time of preparation of the study, the data is regarded as too speculative to yield meaningful tax results. Since the questions of gas pipeline cost and price of gas are still unresolved, the time for making projections with respect to gas production and transportation should be done at some time in the future when more reliable data is available. These observations also hold true for the Kuparuk and Lisburne fields. Moreover, since Alaska's severance tax is its primary source of tax revenue, and since its rate (higher of 10 percent of well-head value or 6.4¢/MCF) times the economic limit factor is the highest (or among the highest) of the states, it does not appear that a significant impact on relative state rankings would occur if and when Prudhoe Bay gas is considered.

Oil and gas production from Cook Inlet is not a significant contributor to taxes under any state's taxing system when compared to Prudhoe Bay and TAPS. The lack of materiality is due to the fact

that the reserves, production, investment, net income, that is, the facts used in measuring tax burden attributable to the Cook Inlet area, even though significant in and of themselves, are not comparatively significant. In addition, the Cook Inlet has been producing for about 18 years and, thus, has neither the remaining life of Prudhoe Bay nor the net-income-producing capacity of Prudhoe Bay and TAPS. .

Discussion with Industry
and Others-

Extensive discussions have been held with experienced employees of both Prudhoe Bay and TAPS and other companies owning oil production and oil pipelines, with various state tax administrative officers and employees, and with personnel within our firm who have expertise with respect to the various state taxes to obtain a better understanding of the administration or practice of the law with respect to the various taxes.

Tariff Rate-

The ICC valuation of \$9,733,600,000 is used as a starting point in both the inflated and noninflated alternatives in determining the valuation of TAPS for each of 25 years.⁵ An annual decline rate approximating three percent is applied to the outstanding valuation in the noninflated alternative to account for depreciation and obsolescence. The decline rate is based on condition percents utilized in ICC valuation methodology. Due to the effect of inflation on

⁵Interstate Commerce Commission, Op. Cit., Appendix 2, p. 2.

valuation in the first five years, the annual decline rate in the inflated alternative is somewhat less, approximating 2.5 percent. A seven-percent rate of return is applied to the ICC valuation to derive a net income after tax for purposes of calculating the TAPS tariff.⁶ (See Exhibits IV and XII.)

In addition to a seven-percent return on investment, all other cash outlays for the 25-year period have been determined. An average TAPS tariff rate is arrived at by dividing the sum of the return on investment and cash outlays by the total estimated 25-year throughput. Franchise taxes, not included in the 1978 report due to their immateriality, have been included for completeness in the updated study as a recoverable cost in arriving at the TAPS tariff.

The derived average tariff rate for the entire life of the pipeline is greater than the initial average ICC approved interim tariff rate of the owner companies because decreasing throughput in later years necessitates a greater recovery of cost per barrel.

The approach taken in the inflated alternative is to inflate the cash outlays for operation, maintenance, and dismantling costs through 1982 at a nine-percent rate. These projected cash outlays for the period 1983-2001 are then expressed in terms of 1982 costs. The return on investment is greater in the inflated alternative due to a lower annual decline rate, i.e., a higher average outstanding valuation. No adjustment for inflation is required for Federal and

⁶United States v. Atlantic Refining Co., C.A. No. 14060, D.D.C., December 23, 1941.

state income taxes since they are a product of a statutory rate and the return on investment. (See Exhibit XII.) The TAPS tariff is adjusted for the variation in ad valorem taxes between states to arrive at an adjusted TAPS tariff for each state in the study.

A TAPS tariff is derived only for purposes of allocating the total market price of Prudhoe Bay crude oil between production operations and pipeline operations in arriving at state taxes. The derived TAPS tariff in no way should be construed as purporting to represent any company's tariff entitlement under accepted ICC methodology.

Wellhead Value-

As in the 1978 report, the updated study assumes that in arriving at average wellhead value, 42-1/2 percent of the crude oil is shipped by tanker to the Gulf Coast for the period 1977 to 1979 and that by 1980 a pipeline will be available to transport the oil to the Midwest at a reduced per barrel cost.⁷ Forty-two and one-half percent of the crude oil is considered excess to the West Coast region throughout the entire 25-year period. The average wellhead value of the oil is therefore decreased to the extent of the incremental cost of transporting 42-1/2 percent of each barrel of crude oil from the West Coast to the Gulf Coast.

The inflated alternative provides for escalation in world oil price consistent with the nine-percent annual increase through

⁷ Alaska North Slope Crude Oil Pricing and Entitlements Treatment, (Federal Energy Administration, 1977), 42 Federal Register 13,119.

1982 in marine and lower-48 pipeline transportation costs used in Pritchard & Abbott. The TAPS tariff also reflects a similar escalation in operating costs. The 1982 transportation costs are considered to remain constant for the period 1983 through 2001.

Royalty Payments-

The study does not consider as a tax the payments made to the State of Alaska for its one-eighth royalty interest; thus, they have not been taken into account in the study.

Royalty Report-

The royalty reports furnished by the companies to the State of Alaska for June, 1977, except that of Exxon for July, 1977, are used as a starting point in the updated study for the world market price of crude oil, transportation charges, and field costs for the 25-year period.

Book/Tax Timing Differences-

Because timing differences reverse over the life of the pipeline, the income tax calculations in the report disregard differences between financial and tax reporting of such items as intangible drilling costs, accelerated depreciation, and accrued dismantling costs.

Average Life Method-

The study uses the average life method for the calculation of ad valorem taxes on TAPS in New Mexico and Texas, and Prudhoe Bay production facilities in Kansas and Texas. Under this method, property

is valued each year of its life at a constant amount, normally 62-1/2 percent of cost. Twelve and one-half percent of the 62-1/2 percent typically represents normal salvage value. The average life value during the first half of the life of the property is theoretically lower than true value, whereas the average life value during the second half of the life of the property is greater than the true value. Because it is difficult to value a pipeline each year, this method has historically been used in Louisiana and Texas. In addition, its use has been of value to local jurisdictions in planning revenue requirements and funding bond issues, since a constant source of tax revenue is determinable and made available. Since the salvage value of TAPS and Prudhoe Bay hardware is negative due to dismantling costs, the study uses 50 percent as the average life method rate.

Unit Appraisal Method-

The ICC valuation of \$9,733,600,000 is used as the best available public data indicator of the value of the pipeline for ad valorem tax valuation purposes in those states mandating a unit appraisal or economic approach to valuation. Deducted from ICC valuation for ad valorem tax purposes in California, Kansas, and Oklahoma is the amount of \$631 million for certain adjustments to value. (See Exhibits VI(a) and XIV(a).) This modification is an estimate and represents capitalization of taxes and certain other negotiated items involving equipment, camps, and roads. In addition, included in the valuation is the amount of \$650 million in 1977 dollars representing an estimate of the assumed Phase III expansion

of the pipeline. This addition is valued at \$700 million in the inflated alternative.

In contrast to the \$9,733,600,000 ICC valuation in the 1973 report, the value of TAPS for the State of Alaska for the year 1978 in the updated study is \$8,100,000,000, since this was the agreed-to amount on which the companies actually paid ad valorem tax in 1978.

Depreciation-

Depreciation (25-year life) of TAPS is obtained from the stated amount of total depreciation in the ICC Order authorizing interim rates. Depreciation on Prudhoe Bay production facilities is determined in the noninflated alternative by recovering total non-inflated capital expenditures for the first 25 years in the Pritchard & Abbott survey and, in the inflated alternative, by recovering total inflated capital expenditures for the first 25 years in the Pritchard & Abbott survey.⁸

⁸Pritchard & Abbott, Op. Cit., Table 6.

FINDINGS

The results of the study establish that in the noninflated

the following is a ranking of the

states under both alternatives. (See Exhibits II and X.)

	Alternative 1 Noninflated Data (In Thousands)	% of Each State to Alaska		Alternative 2 Inflated Data (In Thousands)	% of Each State to Alaska
Alaska	\$12,065,368	100%	Alaska	\$15,612,133	100%
Louisiana	8,762,786	73	Louisiana	11,751,669	75
New Mexico	7,736,278	64	Wyoming	9,653,264	62
Wyoming	7,447,105	62	New Mexico	9,542,374	61
Kansas	7,442,289	62	Oklahoma	9,431,789	60
Oklahoma	7,329,874	61	Kansas	9,396,709	60
Texas	6,485,759	54	Texas	8,485,517	54
California	6,040,652	50	California	6,488,529	42

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Whereas California represents

92 percent and 95 percent of the total tax burden of Alaska in the 1973 report in the noninflated and inflated alternatives, respectively, the percentage of its total tax burden to that of Alaska in the updated study has decreased to 50 percent and 42 percent, respectively.

When reviewing the noninflated studies alone, Alaska's total tax burden increased approximately 14.1 percent in the updated study due to the income tax in Alaska (basically separate accounting) increasing by \$1.8 billion and the ad valorem tax (lower valuation for TAPS) decreasing by approximately \$225 million. California's total tax burden, on the other hand, decreased by approximately 37.6 percent in the updated study due to Proposition 13 both lowering the ad valorem tax rate by more than one half (.05 versus .1119) and limiting the effect of inflation on the valuation of property including oil reserves to two percent per year in California through 1982.

The following tables compare, under both alternatives, the total tax burden computed in the 1978 report to that of the 1979 report. The difference between reports is quantified in the form of a percentage increase or decrease.

ALTERNATIVE I (NONINFLATED DATA)

<u>States as Ranked in 1979 Study</u>	<u>Tax Per 1979 Study</u>	<u>Tax Per 1978 Study</u>	<u>Percentage Increase (Decrease)</u>
1. Alaska	\$12,065,368	\$10,575,289	14.09%
2. Louisiana	8,762,786	8,980,934	(2.43%)
3. New Mexico	7,736,278	7,504,189	3.09%
4. Wyoming	7,447,105	7,387,420	.81%
5. Kansas	7,442,289	7,416,668	.35%
6. Oklahoma	7,329,874	7,375,749	(.62%)
7. Texas	6,435,759	6,375,031	1.74%
8. California	6,040,652	9,677,133	(37.58%)

ALTERNATIVE II (INFLATED DATA)

<u>States as Ranked in 1979 Study</u>	<u>Tax Per 1979 Study</u>	<u>Tax Per 1978 Study</u>	<u>Percentage Increase (Decrease)</u>
1. Alaska	\$15,612,133	\$13,004,851	20.05%
2. Louisiana	11,751,669	11,731,849	.17%
3. Wyoming	9,653,264	9,586,107	.70%
4. New Mexico	9,542,374	8,599,358	10.97%
5. Oklahoma	9,431,789	9,488,207	(.59%)
6. Kansas	9,396,709	9,364,662	.34%
7. Texas	8,485,517	8,390,476	1.13%
8. California	6,488,529	12,419,096	(47.75%)

DISCUSSION

Ad Valorem Taxes-

Alaska--Under Alaska law, when a pipeline begins operating, it is valued for ad valorem tax purposes with due regard to the economic value of the property based on the estimated life of the proven reserves then technically, economically, and legally deliverable to it unless the economic life of those reserves is materially shorter than the estimated physical life of the pipeline. If the economic life of the reserves is materially shorter than the estimated physical life of the pipeline, the full and true value is the actual cost reduced by an annual allowance for depreciation on a straight-line basis over the economic life.⁹

The study utilizes as the best evidence of economic value the agreed to valuation of \$8.1 billion on which ad valorem taxes were actually paid in 1978 (Exhibits VI(a) and XIV(a) reflect this amount plus the Phase III expansion.). This valuation in the noninflated alternative has been reduced by an annual decline rate based on condition percents utilized in ICC rate filings. In the inflated alternative, the annual decline rate is somewhat less due to the effect of inflation through 1982 on the reproduction cost in ICC valuation methodology. For purposes of the study, it is assumed that the taxpayer in 1997 will be able to sustain a finding that the

⁹A.S. Sec. 43.56.060.

economic life of proven reserves is materially shorter than that of the pipeline. Consequently, declines of 57.3 and 64.79 percent in the noninflated and inflated alternatives, respectively, are applied to the 1996 outstanding valuations based on ICC methodology in 1997 to reach depreciated historical cost valuations.

A 25-year average of the hardware tax valuation base from Pritchard & Abbott Table 6, which takes into account a 32-year life, is used to value the Prudhoe Bay Oil production facilities in the inflated alternative. A 25-year average valuation from the same table, adjusted to remove the effects of inflation, has been used to calculate the hardware tax of Prudhoe Bay production facilities in the noninflated alternative.

Since the State of Alaska assesses property at 100 percent of fair market value, the two-percent statutory tax rate is applied to both the valuation for Prudhoe Bay production facilities and TAPS to arrive at total ad valorem taxes in Alaska over a 25-year period.¹⁰

California--For purposes of valuing property in California, the valuation of TAPS is that per ICC with modifications, and for Prudhoe Bay production facilities, data from Pritchard & Abbott Table 6, adjusted to remove the effects of inflation for the noninflated alternative.

The updated study reflects the impact of Proposition 13 added in 1978 to the California constitution.¹¹ However, the study

¹⁰A.S. Sec. 43.56.010(a).

¹¹Constitution of California, Art. XIII A.

does not consider local license taxes. Therefore, total taxes in California may be understated because local jurisdictions in the wake of Proposition 13 have and are contemplating increasing the license tax on the value of oil and gas production. At the time of this writing, the amount of such tax is not subject to quantification.

Since California has a uniform statewide assessment rate of 25 percent, the California tax rate in the updated study is five percent which equals the sum, as provided for in Proposition 13, of one percent of the full cash value plus an estimated .25 percent for retirement of outstanding indebtedness and interest thereon multiplied by four ($5\% \times 25\% = 1.25\%$). In addition, the impact of inflation on valuation is limited as provided for in Proposition 13 to two percent per year applied for years through 1982 consistent with the assumptions in the updated study.

California assesses an ad valorem tax on oil reserves in the ground.¹² An estimate of the discounted future income stream of oil reserves in Prudhoe Bay is obtained from Pritchard & Abbott Table 8. This table is adjusted to take into consideration California taxes. The discount factor of 18 percent is increased to 19.25 percent since California specifically provides that the capitalization rate shall include a property tax component.¹³

Under California assessing practice, the valuation of the production equipment hardware is an offset to the valuation of the oil

¹²Revenue and Taxation Code, Sec. 107.

¹³Rule No. 25 (Cal. Adm. Code).

reserves in the ground since the production equipment is considered an integral cost of severing the minerals. California assesses hardware because it is a requirement under state law that land and improvements thereto be assessed separately.¹⁴ In the noninflated alternative the reserves tax exceeds the hardware tax during the first 14 years of production. Consequently, the ad valorem tax on Prodhoe Bay production facilities is a cumulative total of taxes from the 15th through the 25th year of the life of the field when the hardware tax exceeds that of the tax on the oil reserves. In the inflated alternative, the reserves tax exceeds the hardware tax also for the first 14 years of production, and, thus, from the 15th year through the 25th year, the hardware valuation is used as a basis for calculating ad valorem taxes. (See Exhibits VI(c), VI(b), XIV(b), and XIV(c).)

The one-eighth royalty payment to the state has not been deducted in arriving at the discounted future income stream. Under the Post De Luz Doctrine, a possessory interest on exempt land created after July 26, 1963, is taxed on the full value of the mineral interest.¹⁵

Kansas--The Kansas legislature has provided that all oil leases and oil wells be assessed and taxed as personal property. In addition, it has determined that personal property should be appraised at fair market value in money and assessed at a rate of 30 percent.¹⁶

¹⁴Constitution of California Sec. 13, Art. XIII.

¹⁵De Luz Homes, Inc. v. County of San Diego, 45 Cal. 2d 546 (1955).

¹⁶K.S.A. Secs. 79-329, 79-301, and 79-1439.

Oil production is taxed based on the present worth of recoverable oil over a reasonable length of time after deducting lease operating cost factors and adding to the resultant value the present worth of all lease and well equipment. The prescribed analytical technique in the 1978 Kansas Oil and Gas Appraisal Guide¹⁷ is based on applying a present worth factor, determined from a table, based on a rate of decline factor for the two preceding years' production and applying this present worth factor to total production. Certain prescribed operating cost allowances for production and injection wells are then deducted from this estimated gross income stream to arrive at the valuation of the working interest. Valuation of the oil reserves in Kansas for purposes of the study is based on the same technique as prescribed by the Kansas Department of Revenue.

Kansas utilizes an oil and gas equipment schedule that is based on the cost of the equipment. Through discussions with the Kansas Department of Revenue, it has been determined that the oil and gas equipment schedule has a built-in 60-percent average life method rate. The Prudhoe Bay production equipment for Kansas purposes is valued based on a manner similar to that in Texas in that the average life method rate of 50 percent is applied to the 25-year average of end of the year cost of hardware.

The fair market value of tangible personal property in Kansas means fair market value in money or what a willing buyer will pay a willing seller.¹⁸ By discussion with the Kansas Department of

¹⁷ 1978 Oil and Gas Appraisal Guide, Kansas Department of Revenue, November, 1977.

¹⁸ K.S.A. Sec. 79-501.

Revenue, it has been ascertained that pipelines are valued based on the unit appraisal method of market, income, and cost. Valuation of TAPS for Kansas purposes, like California, is based on ICC valuation with modifications.

Louisiana--The ad valorem tax in Louisiana is calculated under the new Louisiana state constitution which provides that beginning January 1, 1978, interstate pipeline and producing property hardware be valued under a unit appraisal approach. Prior to 1978, the average life method was utilized. Tangible property other than land and residential improvements is to be assessed at a uniform 15-percent rate.¹⁹ The average statewide tax rate of 60 mills is based on information obtained from state administrative officials and confirmed with industry sources.

A 25-year average of inflated hardware tax value from Pritchard & Abbott Table 6 is used as the basis for determining ad valorem taxes in Louisiana under the inflated alternative. In the noninflated alternative, the effect of inflation is removed from these hardware amounts. The ICC valuation with modifications is used as a valuation of TAPS for purposes of the noninflated alternative. The effect of inflation on the addition to the pipeline in 1980 is considered in the inflated alternative.

New Mexico--Pipelines in New Mexico are taxed based on a schedular approach. The pipeline schedule, which is updated every

¹⁹Louisiana Constitution of 1974, Sec. 18, Art. VII.

five years, is based on the average net book value of all pipelines in the state for that five-year period. Consequently, a new pipeline receives a benefit in that its cost is averaged with those of older lines. The use of net book values in arriving at valuations for the schedule is tantamount to the use of an average life method rate of 50 percent. Consequently, the study treats the valuation of TAPS for New Mexico purposes similar to other states which use a pipeline schedule. The average life method rate of 50 percent is applied to the average outstanding cost over 25 years.

The ad valorem tax on production under New Mexico law is included in the severance tax computation-- .015 of the .0424 severance tax rate represents the ad valorem tax on production. (See Exhibits VII and XV.) The taxable value of production is obtained by applying 150 percent to the value of each month's production after deducting royalties paid to the State of New Mexico.²⁰ To this taxable value is then applied the uniform statewide assessment rate of $33\frac{1}{3}$ percent and the average statewide tax rate to arrive at the 1.5-percent effective tax rate on production.

The oil and gas production equipment ad valorem tax in New Mexico is obtained by applying 27 percent to the value of oil production. The statewide uniform assessment rate of $33\frac{1}{3}$ percent and the statewide average tax rate of .03513 are then applied to this amount.²¹

²⁰ N.M.S.A. Sec. 72-22-5.

²¹ N.M.S.A. Sec. 72-24-3(B).

The valuation on Exhibits VI(b) and XIV(b) is the average yearly valuation for 25 years after multiplication by 27 percent.

Oklahoma--TAPS is valued under Oklahoma law based on a unit appraisal approach obtained from the ICC valuation with modifications.²²

Oklahoma imposes no tax on oil reserves, nor does it impose a tax on oil production equipment. A gross production tax is imposed upon oil in lieu of a property tax on oil reserves and oil production equipment.²³ The exemption of oil production equipment from property tax is limited to property used in producing operations, and from discussion with Oklahoma Tax Commission personnel, it has been determined that gathering lines, buildings, and certain other types of facilities extraneous to actual lifting of the crude oil from the ground are taxed under Oklahoma law. Therefore, the study includes a tax on that portion of the Prudhoe Bay production facilities representing items that Oklahoma would tax if the State of Alaska adopted the law of Oklahoma.

Texas--The valuation of TAPS and Prudhoe Bay production facilities under Texas assessment practice is based on historical cost obtained from ICC data and Pritchard & Abbott's Table 6, respectively. Unlike most other states where property is valued for ad valorem tax purposes at the state level, Texas has over 1,500 taxing jurisdictions, each of which values property itself or engages a

²²Oklahoma Constitution, Sec. 8, Art. X.
²³O.S. Tit. 63, Sec. 1001.

valuation firm for this purpose. Consequently, the practice of property valuation in Texas is fractionalized and inconsistent from jurisdiction to jurisdiction. Nonetheless, it has been the practice in Texas for at least 25 years to utilize what is commonly referred to as a Texas Pipeline Schedule having a built-in average life method concept and an assessment rate purported to represent 20 to 25 percent of the property's value.

Even though Texas law defines value to mean fair market value,²⁴ pipeline property is rarely, if ever, assessed at full value. In fact, the use of the pipeline schedule in Texas is not codified in the law.

The Texas Pipeline Schedule was created many years ago by various taxing jurisdictions, valuation firms, and industry representatives. It has been revised at least once and its assumed assessment ratio has been changed to reflect the increased cost of pipeline construction in Texas. Most pipeline companies in Texas are valued based on the Texas Pipeline Schedule or some derivative thereof. Even though the current climate in Texas is somewhat unsettled,²⁵ the vast majority of jurisdictions still use the Texas Pipeline Schedule or its derivative as a basis for valuing pipeline property.

The valuation of the TAPS pipeline under the Texas Pipeline Schedule would not be reasonable since the schedule was created many

²⁴Art. 7149 R.C.S.

²⁵Tenneco, Inc. v. Polk County, 560 S.W.2d 416 (Tex.Civ. App.--
Beaumont, 1977).

years ago based on the then prevailing historical cost of building a pipeline in Texas. Consequently, the calculation of ad valorem taxes for TAPS under Texas law is based on the Texas Pipeline Schedule methodology adjusted for the actual cost of TAPS. The average life method rate of 50 percent is applied to the historical cost of TAPS. The average statewide assessment and tax rates in Texas are then applied to arrive at ad valorem taxes on the pipeline.

The value of an oil and gas lease in Texas is assessable against the lessee.²⁶ Producing property hardware in Texas, in practice, has been valued at nominal amounts. Many jurisdictions place little or no value on the hardware and attribute the value of the entire property, that is, hardware and oil reserves, solely to the oil reserves. As a general "rule of thumb," the value placed on equipment is the present value of any future salvage proceeds from the equipment. In the more sophisticated appraisals of oil reserves in Texas, the value of the producing property hardware is deducted from the discounted future income stream in arriving at the value of the reserves. The validity of this offset is based on the argument that the value of the reserves should take into account the cost of the development of those reserves.

The study shows a separate calculation of the ad valorem tax on Prudhoe Bay production facilities and the oil reserves. (See Exhibits VI(b), VI(c), XIV(b), and XIV(c).) During those years

²⁶Opinion of Attorney General No. 0-6097, July 13, 1944.

of production in which the valuation of the oil reserves exceeds that of the hardware, the value of the hardware is deducted from the value of the oil reserves. In the latter years of the life of the field when the value of the hardware exceeds that of the oil reserves, the value of the hardware only is taxed. Because it is tenuous, at best, to compare the rather complex and costly hardware at Prudhoe Bay to any analogous situation in Texas, the study assumes that the hardware would be placed on an average life method rate of 50 percent of historical cost.

The average statewide assessment rate for Texas is obtained by averaging the assessment rate of all Texas counties, all road districts, a sampling of one school district in each county, and a sampling of cities located in Texas. The county and road district assessment rates are obtained from Texas Municipal Reports, Special Report No. 111, 1976. The average statewide school district assessment rate is obtained by averaging the assessment rates of the first school district listed alphabetically in each county in Texas Assessment Ratios, 2nd Edition, 1977. The average statewide city assessment rate is obtained by sampling the average assessment rate for the first city located in a county of a sampling of every eight counties listed alphabetically in Texas Assessment Ratios, 2nd Edition, 1977. The tax rates for each school district are obtained from the 1976-1977 Texas School Directory. The tax rates for the cities have been obtained from selected industry sources.

The ad valorem tax in Texas on oil reserves is calculated in a manner similar to that in California in that the starting point is Pritchard & Abbott's valuation of reserves in Alaska, Table 8. The figures of Pritchard & Abbott are adjusted to reflect the actual production tax and ad valorem tax under Texas law. A 2.5-percent effective property tax rate and a 4.6-percent effective severance tax rate as percentages of the producers' gross revenues are used to arrive at taxes deductible in obtaining the discounted future income stream of the reserves. As was the case in Pritchard & Abbott's valuation of oil reserves in Alaska, each year's income stream is discounted to the present based on an 18-percent capitalization rate. Since Pritchard & Abbott inflates the price of oil, capital expenditures, and operating expenses, the noninflated alternative is adjusted to remove the inflation effects of these numbers.

Wyoming--Discussion with personnel at the Wyoming Department of Revenue and Taxation and confirmed independently with industry sources indicates that in Wyoming pipeline equipment and producing property equipment is indexed to 1967 cost levels based on a percentage furnished each year by the state which for 1976 was approximately 48 percent. Property is assessed at a uniform 25-percent assessment rate. The average statewide tax rate of .06475 is obtained by averaging the most recent rates experienced by industry sources with that furnished by the Wyoming Department of Revenue. In addition, local jurisdictions impose an ad valorem tax calculated on the previous year's production. This production is assessed at 100 percent.

Severance Tax-

Alaska--Alaska provides for a severance tax of the higher amount obtained from two methods, the percentage of value method or the cents per barrel method.²⁷ The cents per barrel method results in a greater tax in the noninflated alternative. In the inflated alternative, the cents per barrel method results in a greater tax for years 1977 to 1979, whereas the percentage of production method results in a greater tax for years 1980 to 2001. The wellhead value for calculation of the severance tax is the world market price less all applicable transportation costs and tariffs.

Under the percentage of value method, the severance tax rate of 12.25 percent is applied to the total value of production. The tax is further limited by an economic limit factor (ELF) which in the study is calculated to be .826088. The economic limit factor for crude oil production of a lease or property equals one minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is to be paid raised to a power of 460 times the well days in the month divided by the monthly production at the economic limit.²⁸

\$.80 per barrel is the value used for calculation of the tax per barrel under the cents per barrel method. This \$.80 value is subject to change by the Alaska legislature each year.²⁹ The study, however, assumes a constant value of \$.80 per barrel each year over

²⁷A.S. Sec. 43.55.011.
²⁸A.S. Sec. 43.55.013(b).
²⁹A.S. Sec. 43.55.012(a).

the life of production since the change requires legislative action. The tax under the cents per barrel method is also limited by the ELF.

California--The State of California imposes a severance tax based on the annual amount required to support its Division of Oil and Gas.³⁰ The amount of total revenues obtained from this tax in California is insignificant and is not considered in this study.

Kansas--The State of Kansas imposes the following taxes on the production, marketing, or use of oil in Kansas.³¹ The total of these taxes is considered de minimus to the results of the study.

Oil Production Tax - \$.002 per barrel

Oil and Gas Conservation Tax - \$.0025 per barrel

Plugging Abandoned Oil and Gas Wells - \$.0001
per barrel

Louisiana--Louisiana provides for a 12.5-percent severance tax rate and a uniform 25-cent per barrel reduction from wellhead value where the producer transports the oil by his own facilities.³²

New Mexico--New Mexico imposes four taxes on the severance and production of oil. The severance tax is at the rate of 45 cents per barrel for 1977 and 47.9 cents for each year thereafter in the noninflated study; whereas, the severance tax rate has been increased, in the inflated alternative, for each year through 1982 at the same rate as the market price of oil per Pritchard & Abbott.³³ The following

³⁰Public Resources Code, Sec. 3402.

³¹K.S.A. Secs. 65-171d-65-171f and 55-601-55-611.

³²Severance Tax Reg. 633:74-1.

³³N.M.S.A. 72-18-9; Supra, Note 2.

taxes are based on the value of production after deducting royalty payments.

	<u>Percent</u>
Oil and Gas Conservation Tax ³⁴	.19
Oil and Gas Emergency School Tax ³⁵	2.55
Oil and Gas Ad Valorem Production Tax ³⁶	1.50

Total Rate	4.24
	====

The total percent of 4.24 is applied to the taxable value of production. (See Exhibits VII and XV.) The Oil and Gas Ad Valorem Production Tax rate of 1.5 percent is an average statewide rate obtained from discussion with the State of New Mexico Oil and Gas Accounting Commission. For its derivation see the discussion under New Mexico ad valorem tax section.

Oklahoma--Oklahoma imposes a tax equal to seven percent of the gross value of crude oil production.³⁷ Oklahoma also imposes an excise tax equal to .085 percent of the gross value of each barrel of petroleum oil produced in the state. The excise tax is considered immaterial for the study.

Texas--Texas has a uniform production tax rate of 4.6 percent of production.³⁸

³⁴N.M.S.A. 72-20-1.

³⁵N.M.S.A. 72-21-1.

³⁶N.M.S.A. 72-22-1.

³⁷O.S. Tit. 68 Sec. 1001.

³⁸Tx.R.C.S., Tit. 122A, Art. 402.

Wyoming--Wyoming production is taxed at a four-percent rate.³⁹

Income Tax-

General Discussion--The following is a table showing the method of calculating income tax for Prudhoe Bay production activity and TAPS in each of the states tested in the study.

Alaska	
Prudhoe Bay Production Activity	Separate accounting
TAPS	Separate accounting
Other Alaskan Activity	Apportionment of worldwide income
California	Apportionment of worldwide income
Kansas	Consolidated return apportionment
Louisiana	
Prudhoe Bay Production Activity	Separate accounting
TAPS	Separate entity apportionment
New Mexico	Separate entity apportionment
Oklahoma	
Prudhoe Bay Production Activity	Separate accounting
TAPS	Separate entity apportionment
Texas	No income tax
Wyoming	No income tax

Alaska, California, Kansas, New Mexico, and Texas are members of the Multistate Tax Compact. The Compact permits multistate taxpayers to elect to apportion their income in accordance with the Uniform Division of Income for Tax Purposes Act (UDITPA).

The apportionment factor for each of the states using the UDITPA three factor formula is based on information of a proprietary nature furnished by the respective owners and tested for reasonableness. The factors are assumed to remain constant throughout the 25-

³⁹W.S. Sec. 39-227.1:1(a).

year period. The property factor is obtained by determining the ratio of the cost of property in Alaska to the cost of property worldwide. Property is valued at original cost before any depreciation. The payroll factor is arrived at by determining the ratio of total compensation paid to employees within Alaska to the total amount of compensation paid to employees everywhere. The sales factor is determined by the ratio of the percentage of sales of crude oil delivered to a purchaser within the State of Alaska to total sales worldwide. All states in the study utilize a destination sales clause; that is, crude oil delivered to an out-of-state purchaser is deemed an out-of-state sale.

From discussion with the major owners, it has been determined that relatively few sales of crude oil are projected to take place within Alaska. Most states have provisions in their law to allow for the elimination, substitution, or modification of one or more factors when required to properly reflect the taxpayer's activity in the state. Even though the amount of sales in Alaska is relatively minor compared to total sales worldwide, the study does not adjust any of the companies' factors for the effect of these provisions.

Income for both Prudhoe Bay Field operations and TAPS is calculated in total for a 25-year period. The public data for Prudhoe Bay Field operations is obtained, in large part, from Pritchard & Abbott Tables. This evaluation is used to obtain operating expenses, capital additions, and workover related costs.

The operating expenses for TAPS are obtained from the ICC Order. State taxes are those calculated in each respective state. Depreciation for Prudhoe Bay Field and TAPS facilities is obtained by recovering for each of these operations total capital additions over a 25-year period.

For all states except Alaska, an allocable amount of interest expense for ARCO and SOHIO is attributed to Prudhoe Bay operations. The interest expense of ARCO and SOHIO is based on company furnished proprietary information. It is assumed for purposes of the study that Exxon financed its portion of Prudhoe Bay Field development through working capital and, therefore, no allocable interest expense is attributed to its Prudhoe Bay Field operations.

In Alaska the deduction for interest expense for taxable years beginning after 1977 is calculated by applying to interest paid on a worldwide basis the ratio of real and tangible personal property in Alaska to real and tangible property on a worldwide basis. Only interest not capitalized for financial statement purposes is utilized in the computation. In addition, both producing and nonproducing properties are combined for purposes of the property factor.

Pursuant to the new Alaska oil and gas corporation income tax provision, a deduction for general overhead and administrative expense is allowed to explorers and producers of oil and gas. The allocable portion, based on the in-state acreage to out-of-state acreage, is limited to the lesser of worldwide overhead apportioned

to the state, in a manner similar to that afforded noncapitalized interest, or 12 cents for each barrel of the taxpayer's gross oil production. The study utilizes 12 cents per barrel as the basis for the overhead allocation. The cents-per-barrel method should both approximate the actual allocable overhead as well as provide the best information available.

The laws of Oklahoma and Louisiana also allow a deduction for general overhead and administrative expense to producers of oil and gas. For consistency purposes, the study has utilized 12 cents per barrel as a basis for allocating overhead to oil and gas production in those states.

Alaska--In 1978, the Alaska income tax law was amended to provide, beginning in 1978, that income from Alaska oil or gas production and pipeline transportation be determined by separate accounting. Taxable income of such companies from activities other than oil or gas production or pipeline transportation is determined by subtracting taxable income from combined net income and applying the Alaska allocation and apportionment formula, except that both the numerator and denominator of the property, payroll, and sales factors are calculated without reference to oil or gas production or pipeline transportation activity in Alaska.⁴⁰ Combined net income is based on the unitary method of taxation discussed in California below.

No 1977 Alaska income tax has been included in the study because the information with respect to such taxes is regarded as

⁴⁰A.S. 43.21.

proprietary (nonpublic). The omission of such tax does not materially affect the overall results of the study.

California--California utilizes the unitary method of taxation for income tax purposes. Under this method, the total worldwide income of all companies and their owned affiliates (50 percent or more) is apportioned to Alaska based on the UDITPA three factor formula. As in the 1978 study, the companies' worldwide income reported in their 1976 annual reports was used to calculate Alaska and California income tax pursuant to the unitary method of income taxation, i.e., apportionment of worldwide income.

Since British Petroleum Company Limited acquired greater than 50-percent control of SOHIO in 1978, the updated study considers BP-SOHIO as a combined group for the period 1978-2001.

In calculating the income tax of the combined BP-SOHIO group, no consideration is accorded a provision in the proposed U.S.-U.K. Income Tax Treaty, eliminated in 1978 by the U.S. Senate, that would prohibit states from including income of foreign affiliated corporations of a company doing business in a state when that corporation is controlled by a U.K. corporation which is, in turn, controlled by British shareholders.⁴¹

Kansas--Kansas provides that each taxpayer having income from business activity both within and without the state, other than certain excepted activities, allocate and apportion its net income

⁴¹Proposed United States-United Kingdom Tax Treaty, Article 9(4).

as provided under UDITPA.⁴² Kansas also provides for filing under either a separate entity or consolidated return basis. A consolidated return basis is used in the study for each of the owner companies.

Louisiana--Louisiana requires oil production companies not engaged in refinery operations in Louisiana to file based on separate accounting.⁴³ Consequently, a separate calculation of income tax is made for Prudhoe Bay operations assuming each owner company files using separate accounting in Louisiana. No owner company has refinery operations in Alaska that would disqualify this tax accounting method if Alaska adopted the law of Louisiana. Federal income taxes are deductible in arriving at net income in Louisiana.⁴⁴ The deduction for Federal income tax for purposes of the study is based on the statutory 46-percent U.S. tax rate. Louisiana also provides for a 38-percent depletion allowance calculated based on wellhead value,⁴⁵ but the deduction is limited to 50 percent of net income before deducting depletion and Federal income tax.

Separate calculations are also made for the TAPS owner companies using separate entity apportionment for the pipeline entities.

New Mexico--Discussion with the State of New Mexico Bureau of Revenue indicates that New Mexico has no unique filing requirements for pipeline companies and/or oil production companies. A

⁴²K.S.A. 79-3271-79-3284.

⁴³Texas Company v. W.A. Cooper, Collector of Revenue, 107
30.2d 676 (1953).

⁴⁴Art. 47:241.2.

⁴⁵La. R.S. Sec. 47:66.

company can file under either separate accounting, separate entity, or consolidated return basis. For purposes of the study, it is assumed that each of the owner companies elects to file under a separate entity basis in New Mexico. If each company files on a consolidated basis, the results are not materially different than those obtained under separate entity filing. The New Mexico Bureau of Revenue can compel a taxpayer to file under that method which most accurately reflects income for New Mexico tax purposes.

Oklahoma--As in Louisiana, oil production companies in Oklahoma are required to file on a separate accounting basis.⁴⁶ Also, Oklahoma provides for a depletion allowance of 22 percent of gross income from production. Oklahoma provides for a deduction for accrued Oklahoma state income tax which reduces the tax rate from a statutory four percent to an effective tax rate of 3.84 percent.

Oklahoma, in apportioning income from both within and without the state, provides that in the case of a pipeline enterprise a traffic unit factor be used in lieu of the sales factor. The traffic factor is based on the number of miles of transportation of oil value within Oklahoma to the number of miles of transportation of oil value everywhere.⁴⁷

Texas and Wyoming--Neither Texas nor Wyoming has an income tax.

⁴⁶O.S. Sec. 2358(3)(a).

⁴⁷O.S. Tit. 68. Sec. 878(g)(3).

Franchise Tax-

Alaska--Alaska charges a nominal flat fee as an annual franchise tax on domestic and foreign corporations. The rate is \$50 for a domestic corporation and \$100 for a foreign corporation.⁴⁸

California--The franchise tax in California, since it is measured by the net income derived from business in California, is treated as an income tax in the study.

Kansas--In Kansas, each foreign corporation pays an annual franchise tax in an amount equal to \$1 for each \$1,000 of the corporation shareholders' equity attributable to Kansas. The maximum franchise tax is \$2,500 per company.⁴⁹

Louisiana--The annual franchise tax rate of \$1.50 per thousand is applied to the greater of apportioned assessed value of real and personal property or apportioned capital. Capital includes capital stock, surplus, undivided profits, and borrowed capital. Capital totals and apportionment factors are derived from Forms P, 10-K, 12-K, as well as other proprietary information furnished by the owner companies.

The apportionment factor applied to assessed value is the average of a receipts factor (ratio of total receipts in Louisiana to total receipts everywhere) and a property factor (ratio of assets located in the state to assets located everywhere).⁵⁰

⁴⁸A.S. Sec. 10.05.717.

⁴⁹K.S.A. Sec. 17-7505.

⁵⁰La. R.S. Sec. 47:601-615.

The calculations are made on a company-by-company basis for one year and then multiplied by 25 for purposes of a 25-year comparative study. (See Exhibits IX(a) and XVII(a).) In applying the 25-year factor, the following assumptions are utilized.

- (1) Capital stock, surplus, borrowed capital, and apportionment factors remain constant.
- (2) An average outstanding valuation derived from the property tax schedule is utilized for assessed value of the property, and
- (3) An average outstanding undivided profits account balance is determined by adding average book income, that is, book income less applicable Federal and state taxes averaged over 25 years, to the 1976 account balance with no provision for dividends.

New Mexico--Each domestic and foreign corporation engaged in business in this state is subject to an annual franchise tax. The rate of tax is 55 cents for each \$1,000 or fraction thereof of the book value of its outstanding stock for 1977 and net worth for the period 1978-2001. Such capital is apportioned to New Mexico based on property and business within the state.

Oklahoma--The rate of tax is \$1.25 per \$1,000 of capital employed within the state. The maximum franchise tax is \$20,000 per company. For purposes of this study, we have assumed that the maximum franchise tax is applicable.

Texas--The annual franchise tax rate is \$4.25 per thousand. The franchise base is the greater of apportioned (based on gross receipts) capital (capital does not include debt) or county-assessed

value of Texas property.⁵¹ The statute provides for an 80-percent reduction in franchise tax where an intangibles tax liability exists.⁵² All oil pipeline companies whether or not common carriers are subject to the intangibles tax.⁵³ The intangibles tax is computed as follows: net operating income (Federal income tax is generally allowed as a deduction although not specifically allowed by statute) is capitalized at seven percent; the resulting valuation is reduced by book value and then assessed at 25 percent; then the assessed valuation is subject to a 1.25-percent tax rate.⁵⁴

For purposes of the study, average net operating income and outstanding book value are utilized in calculating the intangibles tax for one representative period. The result is then multiplied by 25 for purposes of the 25-year comparative study.

Wyoming--The franchise tax is applied to the assessed valuation of corporate property located and employed within the state. The study assumes that the maximum tax rate applicable is \$50 per every \$1,000,000 of assessed valuation.

Sales and Use Tax-

Sales taxes generally are measured as a percentage of retail sales price or gross receipts from sales of tangible personal property. Sales or receipts qualifying for sales tax vary from state to state due to the many statutory exemptions and peculiarities of

⁵¹Tx. R.C.S. Tit. 122A Arts. 12.01-12.02.

⁵²Tx. R.C.S. Tit. 122A Art. 12.01(2).

⁵³Tx. R.C.S. Tit. 122 Art. 7105.

⁵⁴Tx. R.C.S. Tit. 122 Arts. 7098-7116.

state law. The use tax is a supplement to the sales tax law. Items subject to use tax are items bought out-of-state for in-state use or consumption. The following is a table of state sales and use tax rates. In depicting the sales/use tax liability, the tables assume that 50 percent of materials and services utilized in the expansion of the production and pipeline facilities during the period 1977-2001 will be subject to the use tax.

<u>State</u>	<u>Sales</u>	<u>Use</u>	<u>Use Tax Liability</u> <u>1977-2001</u> (Thousands)
Alaska*	None	None	None
California*	4.75%	4.75%	\$211,858
Kansas*	3.00%	3.00%	133,805
Louisiana*	3.00%	3.00%	133,805
New Mexico*	3.75%	3.75%	167,257
Oklahoma*	2.00%	4.00%	178,407
Texas*	4.00%	4.00%	178,407
Wyoming*	3.00%	3.00%	133,805

*Local tax rates are additional and vary from state to state.

Possible sales or use tax on equipment or services which have already been purchased and put to use are beyond the scope of the study.

Miscellaneous Taxes-

Several states have levied taxes in conjunction with their severance tax for purposes of oil conservation and regulation activities. These taxes are generally levied based on the annual budgetary requirement of the conservation or regulatory department involved and are insignificant in amount. They are ignored for purposes of this study.

The only additional tax noted in the review of the applicable state laws is a New Mexico pipeline tax based on mileage and diameter.

-41-

It is estimated the tax would approximate only about \$250,000 over the life of the project.

EXHIBITS

I. Percentage Ownership Interests	
II. Summary of Total Taxes	(Noninflated)
III. Calculation of Wellhead Value of Prudhoe Bay Oil	(Noninflated)
IV. TAPS Tariff Determination	(Noninflated)
V. Summary of Total Taxes by Major Owners	(Noninflated)
VI. Ad Valorem Tax Summary	(Noninflated)
(a) Calculation of ad valorem tax on pipeline	(Noninflated)
(b) Calculation of ad valorem tax on Prudhoe Bay Field Hardware	(Noninflated)
(c) Calculation of ad valorem tax on oil reserves	(Noninflated)
VII. Calculation of Severance Tax	(Noninflated)
VIII. Income Tax Summary	(Noninflated)
(a) Calculation of Alaska taxable income	(Noninflated)
(b) Calculation of California taxable income	(Noninflated)
(c) Calculation of Kansas taxable income	(Noninflated)
(d) Calculation of Louisiana taxable income	(Noninflated)
(e) Calculation of New Mexico taxable income	(Noninflated)
(f) Calculation of Oklahoma taxable income	(Noninflated)

IX. Franchise Tax Summary	(Noninflated)
(a) Calculation of Louisiana franchise tax	(Noninflated)
(b) Calculation of New Mexico franchise tax	(Noninflated)
(c) Calculation of Texas franchise tax	(Noninflated)
(d) Calculation of Texas intangibles tax on pipeline	(Noninflated)
(e) Calculation of Wyoming franchise tax	(Noninflated)
X. Summary of Total Taxes	(Inflated)
XI. Calculation of Wellhead Value of Prudhoe Bay Oil	(Inflated)
XII. CAPS Tariff Determination	(Inflated)
XIII. Summary of Total Taxes by Major Owners	(Inflated)
XIV. Ad Valorem Tax Summary	(Inflated)
(a) Calculation of ad valorem tax on pipeline	(Inflated)
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(c) Calculation of ad valorem tax on oil reserves	(Inflated)
XV. Calculation of Severance Tax	(Inflated)
XVI. Income Tax Summary	(Inflated)
(a) Calculation of Alaska income tax	(Inflated)
(b) Calculation of California taxable income	(Inflated)
(c) Calculation of Kansas taxable income	(Inflated)
(d) Calculation of Louisiana taxable income	(Inflated)
(e) Calculation of New Mexico taxable income	(Inflated)
(f) Calculation of Oklahoma taxable income	(Inflated)

XVII. Franchise Tax Summary

(Inflated)

(a) Calculation of Louisiana franchise
tax

(Inflated)

(b) Calculation of New Mexico franchise
tax

(Inflated)

(c) Calculation of Texas franchise
tax

(Inflated)

(d) Calculation of Texas intangibles
tax on pipeline

(Inflated)

(e) Calculation of Wyoming franchise
tax

(Inflated)

COMPARATIVE STATE TAX BURDEN STUDYPERCENTAGE OWNERSHIP INTERESTS

	Prudhoe Oil Pool Percent
Atlantic Richfield Company	20.2745
Exxon Corporation	20.2745
SOHIO Petroleum Company	53.1552

Subtotal	93.7042
Other entities	6.2958

Total	100.0000
	=====

	Trans-Alaska Pipeline System (TAPS) Percent
ARCO Pipe Line Company	21.00
BP Pipelines, Inc.	15.84
Exxon Pipe Line Company	20.00
SOHIO Pipe Line Company	33.34

Subtotal	90.18
Other entities	9.82

Total	100.00
	=====

EXHIBIT II
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

SUMMARY OF TOTAL TAXES

(In Thousands)

<u>Rank</u>	<u>State</u>	<u>Exhibit</u>	<u>Ad Valorem Tax</u>	<u>Severance Tax</u>	<u>Income Tax</u>	<u>Franchise Tax</u>	<u>Total Tax</u>	<u>Percentage of Each State to Alaska</u>
1	Alaska	V	\$4,021,389	\$4,707,640	\$3,336,339	\$ N/A	\$12,065,368	100%
2	Louisiana	V	2,006,948	5,378,304	1,098,034	279,500	8,762,786	73
3	New Mexico	V	1,198,132	5,314,289	1,194,336	29,521	7,736,278	64
4	Wyoming	V	5,625,395	1,817,935	N/A	3,775	7,447,105	62
5	Kansas	V	6,583,660	N/A	858,188	441	7,442,289	62
6	Oklahoma	V	3,241,956	3,051,740	1,032,678	3,500	7,329,874	61
7	Texas	V	4,003,438	2,080,796	N/A	401,525*	6,485,759	54
8	California	V	4,247,704	N/A	1,792,948	N/A	6,040,652	50

* Includes intangibles tax on pipeline.

EXHIBIT III
NONINFLATED

COMPARATIVE TAX BURDEN STUDY
CALCULATION OF WELTHEAD VALUE OF PRODUCE MAY OIL

(Per Barrel)

	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Market price at destination (A)	\$13.30	\$13.30	\$13.30	\$13.30	\$13.30	\$13.30	\$13.30	\$13.30
TAPS tariff (B)	\$ 5.54	\$ 5.47	\$ 5.55	\$ 5.35	\$ 5.33	\$ 5.52	\$ 5.29	\$ 5.26
Tanker Valdes to California (C)	\$.97	\$.97	\$.97	\$.97	\$.97	\$.97	\$.97	\$.97
Tanker California to Gulf Coast (E)	\$ 2.50	\$ -	\$ 2.50	\$ -	\$ 2.50	\$ -	\$ 2.50	\$ -
Pipeline California to Mid-Continent (E)	\$ -	\$ 1.50	\$ -	\$ 1.50	\$ -	\$ 1.50	\$ -	\$ 1.50
Oil destination-California (F)	\$7-1/2%	\$7-1/2%	\$7-1/2%	\$7-1/2%	\$7-1/2%	\$7-1/2%	\$7-1/2%	\$7-1/2%
Gulf Coast (F)	\$2-1/2%	\$2-1/2%	\$2-1/2%	\$2-1/2%	\$2-1/2%	\$2-1/2%	\$2-1/2%	\$2-1/2%
Weighted average--wellhead value (Pump Station #1)	\$ 5.73	\$ 6.15	\$ 6.22	\$ 6.14	\$ 6.34	\$ 5.75	\$ 5.98	\$ 6.01
Weighted average--classified field cost (G)	\$.63	\$.63	\$.63	\$.63	\$.63	\$.63	\$.63	\$.63
Royalty value	\$ 1.10	\$ 1.12	\$ 1.17	\$ 1.11	\$ 1.29	\$ 1.12	\$ 1.15	\$ 1.18

1. Average of market price per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon.

(3) See Exhibit IV.

(C) Average of tanker cost to West Coast per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon.

(D) Appropriate incremental cost to GCHIO of transportation cost to Gulf Coast per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon.

(E) Assumes that a pipeline would be available on January 1, 1977, to move oil from California to Mid-Continent. Tariff of \$1.50 per barrel obtained from Federal Energy Administration. Alaska, Texas, Louisiana, and Wyoming are assumed to be connected to the pipeline by 1977. (See Exhibit V).

(F) Average of market price per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon.

(G) Weighted average per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon.

EXHIBIT IV
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

TAPS TARIFF DETERMINATION

1977-2001

(In Thousands)

	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Oil spill funds (A)	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000
Operation and maintenance (B)	5,677,269	5,677,269	5,677,269	5,677,269	5,677,269	5,677,269	5,677,269	5,677,269
Depreciation (C)	9,964,650	9,964,650	9,964,650	9,964,650	9,964,650	9,964,650	9,964,650	9,964,650
Interest (D)	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000
State taxes (E)	3,986,983	3,382,063	4,030,487	2,272,425	2,110,027	3,770,807	1,778,350	1,555,100
Dismantling costs (F)	1,049,000	1,049,000	1,049,000	1,049,000	1,049,000	1,049,000	1,049,000	1,049,000
Federal income tax (G)	8,661,253	8,661,253	8,661,253	8,661,253	8,661,253	8,661,253	8,661,253	8,661,253
Return on investment (H)	10,100,000	10,100,000	10,100,000	10,100,000	10,100,000	10,100,000	10,100,000	10,100,000
Total	\$48,158,155	\$47,553,235	\$48,201,659	\$46,443,597	\$46,281,199	\$47,941,979	\$45,949,522	\$45,726,272
Throughput (25 years) (barrels)	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000
Average tariff rate	\$5.54	\$5.47	\$5.55	\$5.35	\$5.33	\$5.52	\$5.29	\$5.26

(A) Estimate furnished by owner companies.

(B) \$.938 per barrel less ad valorem tax component.

(C) Recover entire cost from Interstate Commerce Commission order plus Phase III expansion.

(D) 8.582 percent interest rate, principal of \$8,034,480 paid on linear basis.

(E) Maximum state rate applied to sum of (G) and (H) plus ad valorem tax and franchise tax.

(F) \$41.96 million per year for 25 years.

(G) 48/52 applied to (H) for 1977 and 1978; 46/54 applied to (H) after 1978.

(H) 7 percent of total outstanding valuation for 25 years (\$144,285,720).

EXHIBIT V
NONINFLATED
(Continued)

-2-

	Exhibit	Atlantic Richfield Company and/or Subsidiaries	British Petroleum Company Limited and/or Subsidiaries	Exxon Corporation and/or Subsidiaries	The Standard Oil Company of Ohio and/or Subsidiaries	Total
Oklahoma tax-						
Ad valorem	VI	\$ 746,813	\$ 482,863	\$ 716,329	\$1,295,951	\$ 3,241,956
Severance	VII	660,296	N/A	660,296	1,731,148	3,051,740
Income	VIII	194,678	117,765	220,453	499,782	1,032,678
Franchise	IX	1,000	500	1,000	1,000	3,500
		-----	-----	-----	-----	-----
Total		\$1,602,787	\$ 601,128	\$1,598,078	\$3,527,881	\$ 7,329,874
		=====	=====	=====	=====	=====
Texas tax-						
Advalorem	VI	\$ 890,467	\$ 258,192	\$ 874,167	\$1,980,612	\$ 4,003,438
Severance	VII	450,216	N/A	450,216	1,180,364	2,080,796
Income		N/A	N/A	N/A	N/A	NONE
Franchise*	IX	88,950	27,200	87,350	198,025	401,525
		-----	-----	-----	-----	-----
Total		\$1,429,633	\$ 285,392	\$1,411,733	\$3,359,001	\$ 6,485,759
		=====	=====	=====	=====	=====
Wyoming tax-						
Ad valorem	VI	\$1,240,274	\$ 246,154	\$1,224,734	\$2,914,233	\$ 5,625,395
Severance	VII	393,341	N/A	393,341	1,031,253	1,817,935
Income		N/A	N/A	N/A	N/A	NONE
Franchise	IX	825	200	825	1,925	3,775
		-----	-----	-----	-----	-----
Total		\$1,634,440	\$ 246,354	\$1,618,900	\$3,947,411	\$ 7,447,105
		=====	=====	=====	=====	=====

* Includes intangibles tax on pipeline.

EXHIBIT VI
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

AD VALOREM TAX SUMMARY

(In Thousands)

	Exhibit	Atlantic Richfield Company/ ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/ SOHIO Pipe Line Company	Total
Alaska-						
Pipeline	VI(a)	\$ 466,919	\$252,191	\$ 444,685	\$ 741,290	\$2,005,085
Prudhoe Bay Field hardware	VI(b)	436,262	N/A	436,262	1,143,780	2,016,304
Prudhoe Bay reserves	VI(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 903,181	\$352,191	\$ 880,947	\$1,885,070	\$4,021,389
California-						
Pipeline	VI(a)	\$ 399,128	\$301,056	\$ 380,122	\$ 633,663	\$1,713,969
Prudhoe Bay Field hardware	VI(b)	105,203	N/A	105,203	275,818	486,224
Prudhoe Bay reserves	VI(c)	443,014	N/A	443,014	1,161,483	2,047,511
Total		\$ 947,345	\$301,056	\$ 928,339	\$2,070,964	\$4,247,704
Kansas-						
Pipeline	VI(a)	\$ 580,409	\$437,794	\$ 552,770	\$ 921,468	\$2,492,441
Prudhoe Bay Field hardware	VI(b)	363,912	N/A	363,912	954,096	1,681,920
Prudhoe Bay reserves	VI(c)	521,293	N/A	521,293	1,366,713	2,409,299
Total		\$1,465,614	\$437,794	\$1,437,975	\$3,242,277	\$6,583,660
Louisiana-						
Pipeline	VI(a)	\$ 256,064	\$193,145	\$ 243,870	\$ 406,531	\$1,099,610
Prudhoe Bay Field hardware	VI(b)	196,318	N/A	196,318	514,702	907,338
Prudhoe Bay reserves	VI(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 452,382	\$193,145	\$ 440,188	\$ 921,233	\$2,006,948
New Mexico-						
Pipeline	VI(a)	\$ 245,910	\$185,436	\$ 234,200	\$ 390,411	\$1,056,007
Prudhoe Bay Field hardware	VI(b)	30,751	N/A	30,751	80,623	142,125
Prudhoe Bay reserves	VI(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 276,661	\$185,486	\$ 264,951	\$ 471,034	\$1,198,132
Oklahoma-						
Pipeline	VI(a)	\$ 640,159	\$482,863	\$ 609,675	\$1,016,326	\$2,749,025
Prudhoe Bay Field hardware	VI(b)	106,654	N/A	106,654	279,623	492,931
Prudhoe Bay reserves	VI(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 746,813	\$482,863	\$ 716,329	\$1,295,951	\$3,241,956
Texas-						
Pipeline	VI(a)	\$ 342,300	\$258,192	\$ 326,000	\$ 543,442	\$1,469,934
Prudhoe Bay Field hardware	VI(b)	290,772	N/A	290,772	762,339	1,343,883
Prudhoe Bay reserves	VI(c)	257,395	N/A	257,395	674,831	1,189,621
Total		\$ 890,467	\$258,192	\$ 874,167	\$1,980,612	\$4,003,438
Wyoming-						
Pipeline	VI(a)	\$ 326,340	\$246,154	\$ 310,800	\$ 518,103	\$1,401,397
Prudhoe Bay Field hardware	VI(b)	277,213	N/A	277,213	726,791	1,281,217
Prudhoe Bay reserves	VI(c)	636,721	N/A	636,721	1,669,339	2,942,781

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF AD VALOREM TAX ON PIPELINE
(In Thousands)

	Percentage Ownership in TAPS	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Average outstanding historical cost		\$ N/A	\$ N/A	\$ N/A	\$ N/A	\$8,000,000	\$ N/A	\$8,000,000	\$8,000,000
Unit appraisal valuation		8,672,000	10,305,600	10,305,600	10,305,600	N/A	10,305,600	N/A	N/A
Modifications to unit appraisal valuation		N/A	(631,000)	(631,000)	(631,000)	N/A	(631,000)	N/A	N/A
100% valuation		\$8,672,000	\$ 9,674,600	\$ 9,674,600	\$ 9,674,600	\$8,000,000	\$ 9,674,600	\$8,000,000	\$8,000,000
Average life rate		N/A	N/A	N/A	N/A	.50***	N/A	.50***	.48***
Average of annual decline rate		x .5127839*	x .5370609**	x .5601607**	x .5601607**	N/A	x .5601607**	N/A	N/A
Average assessment ratio		\$4,446,862 x 1.00	\$ 5,195,849 x .25	\$ 5,419,331 x .30	\$ 5,419,331 x .15	\$4,000,000 x .33-1/3	\$ 5,419,331 x .30	\$4,000,000 x .418	\$3,840,000 x .25
Assessed value of property		\$4,446,862	\$ 1,298,962	\$ 1,625,799	\$ 812,900	\$1,333,333	\$ 1,625,799	\$1,672,000	\$ 960,000
Tax rate		x .02	x .05	x .068	x .06	x .03513	x .075	x .0389951	x .06475
Tax for 100% ownership--one year		\$ 88,937	\$ 64,948	\$ 110,554	\$ 48,774	\$ 46,840	\$ 121,935	\$ 65,200	\$ 62,160
Tax for 100% ownership--25 years		\$2,223,425	\$ 1,900,609****	\$ 2,763,850	\$ 1,219,350	\$1,171,000	\$ 3,048,375	\$1,630,000	\$1,554,000
AHCO Pipe Line Company	21.0	\$ 466,919	\$ 399,128	\$ 580,409	\$ 256,064	\$ 245,910	\$ 640,159	\$ 342,300	\$ 326,340
BP Pipelines, Inc.	15.84	352,191	301,056	437,794	193,145	185,486	482,863	258,192	246,154
Exxon Pipe Line Company	20.0	444,685	380,122	552,770	243,870	234,200	609,675	326,000	310,800
SOHIO Pipe Line Company	33.34	741,290	633,663	921,469	406,531	390,411	1,016,328	543,442	518,103
Total		\$2,005,085	\$ 1,713,969	\$ 2,492,441	\$ 1,099,610	\$1,056,007	\$ 2,749,025	\$1,469,934	\$1,431,397

* Provision for an approximate 3.0 percent annual decline rate through 1996; a decline of 57.3 percent in 1997 is provided for in order to reach a depreciated historical cost valuation. Such a reduction would be reasonable upon a showing by the taxpayer that the economic life of the proven reserves is materially shorter than that of the pipeline.

** Provision for an approximate 3.0 percent annual decline rate.

*** Negative salvage assumed.

**** Index of 1967 costs per Wyoming Department of Revenue.

***** Tax attributable to the period preceding July 1, 1978, is computed utilizing the pre-Proposition 13 tax rate of .1119.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF AD VALOREM TAX ON PRUDHOE BAY FIELD HARDWARE
(In Thousands)

	Percentage Ownership in Prudhoe Field	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
100% valuation		\$4,303,560**	\$3,773,727***	\$7,038,920**	\$4,303,560**	\$518,074****	\$935,200**	\$7,038,920**	\$7,038,920**
Index to 1967 costs--Wyoming		N/A	N/A	N/A	N/A	N/A	N/A	N/A	x .48
Average life rate		N/A	N/A	x .50*	N/A	N/A	N/A	x .50*	N/A
Average assessment ratio		\$4,303,560 x 1.00	\$3,773,727 x .25	\$3,519,460 x .30	\$4,303,560 x .15	\$518,074 x .33-1/3	\$935,200 x .30	\$3,519,460 x .418	\$3,378,682 x .25
Assessed value of property		\$4,303,560	\$ 943,432	\$1,055,838	\$ 645,534	\$172,691	\$280,560	\$1,471,134	\$ 844,670
Tax rate		x .02	x .05	x .068	x .06	x .03513	x .075	x .0389951	x .06475
Tax for 100% ownership--1 year		\$ 86,071	\$ 47,172	\$ 71,797	\$ 38,732	\$ 6,067	\$ 21,042	\$ 57,367	\$ 54,692
Tax for 100% ownership--25 years		\$2,151,775	\$ 518,892***	\$1,794,925	\$ 968,300	\$151,675	\$526,050	\$1,434,175	\$1,367,300
Atlantic Richfield Company	20.2745	\$ 436,262	\$ 105,203	\$ 363,912	\$ 196,318	\$ 30,751	\$106,654	\$ 290,772	\$ 277,213
Exxon Corporation	20.2745	436,262	105,203	363,912	196,318	30,751	106,654	290,772	277,213
CONHO Petroleum Company	53.1552	1,143,780	275,818	954,096	514,702	80,623	279,623	762,339	726,791
		\$2,016,304	\$ 486,224	\$1,681,920	\$ 907,338	\$142,125	\$492,931	\$1,343,883	\$1,281,217

* Negative salvage assumed.

** For Alaska, Louisiana, and Oklahoma, used 25-year average of noninflated hardware tax value computed from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6. However, Oklahoma is exclusive of production equipment. Kansas, Texas, and Wyoming are based on a 25-year average of cumulative noninflated capital expenditures from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6.

*** Valuation is based on an 11-year average of noninflated hardware tax value base from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6 (1991-2001), during which period the ad valorem tax on Prudhoe Bay Field equipment exceeds tax on Prudhoe Bay oil reserves. See Exhibit VI(c).

**** Valuation is based on a 25-year average of gross production net of royalty multiplied by taxable value factor of 27 percent.

EXHIBIT VI(c)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF AD VALOREM TAX ON RESERVES

(In Thousands)

	Percentage Ownership in Reserves	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Valuation modification to Texas valuation for field hardware offset		\$ N/A	\$11,276,240	\$5,041,518	\$ N/A	\$ N/A	\$ N/A	\$ 9,082,786 **	\$1,940,079
		N/A	-	-	N/A	N/A	N/A	(3,519,456)	-
Valuation as modified by average assessment ratio		\$ N/A	\$11,276,240	\$5,041,518	\$ N/A	\$ N/A	\$ N/A	\$ 5,563,330	\$1,940,079
		N/A	x .25	x .30	N/A	N/A	N/A	x .418	x 1.00
Severed value average tax rate		\$ N/A	\$ 2,819,060	\$1,512,455	\$ N/A	\$ N/A	\$ N/A	\$ 2,325,472	\$1,940,079
		N/A	x .05	x .068	N/A	N/A	N/A	x .0389951	x .06475
x on 100% ownership--one year		\$ N/A	\$ 140,953	\$ 102,847	\$ N/A	\$ N/A	\$ N/A	\$ 90,682	\$ 125,620
x on 100% ownership--25 years		\$ N/A	\$ 2,185,079	\$2,571,175	\$ N/A	\$ N/A	\$ N/A	\$ 1,269,549 **	\$3,140,500
Atlantic Richfield Company	20.2745	\$ N/A	\$ 443,014	\$ 521,293	\$ N/A	\$ N/A	\$ N/A	\$ 257,395	\$ 636,721
Conoco Corporation	20.2745	N/A	443,014	521,293	N/A	N/A	N/A	257,395	636,721
HIO Petroleum Company	53.1552	N/A	1,161,483	1,366,713	N/A	N/A	N/A	674,831	1,669,339
	93.7042	\$ N/A	\$ 2,047,511	\$2,409,299	\$ N/A	\$ N/A	\$ N/A	\$ 1,189,621	\$2,942,781

* Tax for the period January 1, 1977, to June 30, 1978, is based on pre-Proposition 13 law. The valuation is based on a 12-1/2-year average (July 1, 1978-1990). During the 14-year period (1977-1990), reserves valuation exceeds that of the hardware; however, beginning in 1991 and thereafter, the reserves tax is inapplicable as the hardware valuation exceeds that of reserves.

** Valuation is based on a 14-year average (1977-1990), during which period reserves valuation exceeds that of the hardware. Unlike California, a modification is provided for in reserves valuation since in Texas the hardware tax is separately stated. Beginning in 1991 and thereafter the reserves tax is inapplicable, as the hardware valuation exceeds that of the reserves.

COMPARATIVE STATE TAX BURDEN STUDY

CALCULATION OF SEVERANCE TAX

(In Thousands)

	Alaska***	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Percentage production-								
Estimated total production (in barrels)	NONE	N/A	N/A	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000
Less- Royalty (in barrels)	NONE	N/A	N/A	1,086,000	1,086,000	1,086,000	1,086,000	1,086,000
Net taxable production (in barrels)	NONE	N/A	N/A	7,602,000	7,602,000	7,602,000	7,602,000	7,602,000
Wellhead price per barrel								
Net taxable production	\$ NONE	\$ N/A	\$ N/A	\$45,917,287	\$47,969,828	\$46,525,448	\$48,273,908	\$48,501,907
Tax rate	x .1225	N/A	N/A	x .125	x .0424	x .07	x .046	x .04
Total percentage production (A)	\$ NONE	\$ N/A	\$ N/A	\$ 5,739,661	\$ 2,033,921	\$ 3,256,781	\$ 2,220,600	\$ 1,940,079
Cents per barrel-								
Estimated total production (in barrels)	8,688,000	N/A	N/A	N/A	8,688,000	N/A	N/A	N/A
Less- Royalty (in barrels)	1,086,000	N/A	N/A	N/A	1,086,000	N/A	N/A	N/A
Net taxable production (in barrels)	7,602,000	N/A	N/A	N/A	7,602,000	N/A	N/A	N/A
Tax rate per barrel	x .80	N/A	N/A	N/A	x ****	N/A	N/A	N/A
Total cents per barrel (B)	\$6,081,600	\$ N/A	\$ N/A	\$ N/A	\$ 3,637,425	\$ N/A	\$ N/A	\$ N/A
Total tax (Total A and B)	\$6,081,600	\$ N/A	\$ N/A	\$ 5,739,661	\$ 5,671,346	\$ 3,256,781	\$ 2,220,600	\$ 1,940,079
Economic limit factor (Alaska)	x .826088	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tax for 100% ownership--25 years	\$5,073,937	\$ N/A	\$ N/A	\$ 5,739,661	\$ 5,671,346	\$ 3,256,781	\$ 2,220,600	\$ 1,940,079
Atlantic Richfield Company--20.2745%	\$1,018,578	\$ N/A	\$ N/A	\$ 1,163,688	\$ 1,149,837	\$ 660,296	\$ 450,216	\$ 393,341
Exxon Corporation--20.2745%	1,018,578	N/A	N/A	1,163,688	1,149,837	660,296	450,216	393,341
Shell Petroleum Company--53.1552%	2,670,484	N/A	N/A	3,050,928	3,014,615	1,731,148	1,190,364	1,031,253
Total	\$4,707,640	\$ N/A	\$ N/A	\$ 5,378,304	\$ 5,314,289	\$ 3,051,740	\$ 2,080,736	\$ 1,817,935

* See Exhibit III.

** The wellhead price as computed on Exhibit III is reduced by a 25 cents per barrel allowance for oil gathering facilities.

*** The wellhead price does not yield an effective percentage production tax rate in excess of \$.80 per barrel, therefore, the percentage of production method is not applicable.

**** The tax rate for 1977 is \$.45 per barrel and for the period 1978 to 2001 is \$.479 per barrel.

EXHIBIT VIII
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

INCOME TAX SUMMARY

(In Thousands)

	<u>Exhibit</u>	<u>Atlantic Richfield Company and/or Subsidiaries</u>	<u>British Petroleum Company Limited and/or Subsidiaries</u>	<u>Exxon Corporation and/or Subsidiaries</u>	<u>The Standard Oil Company of Ohio and/or Subsidiaries</u>	<u>Total</u>
Alaska--separate accounting for Prudhoe Bay Field and TAPS and worldwide basis for other income	VIII(a)	\$776,112	\$309,139	\$781,028	\$1,470,060	\$3,336,339
California--worldwide basis	VIII(b)	204,863	809,088	510,231	268,766	1,792,948
Kansas--consolidated return basis	VIII(c)	143,317	212,798	101,027	401,046	358,183
Louisiana--separate accounting for Prudhoe Bay Field and separate entity for TAPS	VIII(d)	210,534	132,924	226,537	527,739	1,093,034
New Mexico--separate entity	VIII(e)	200,809	154,979	264,936	573,562	1,194,336
Oklahoma--separate accounting for Prudhoe Bay Field and separate entity for TAPS	VIII(f)	194,678	117,765	220,453	499,782	1,032,678

EXHIBIT VIII(a)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF ALASKA TAXABLE INCOME

FOR THE PERIOD 1978-2001

(In Thousands)

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field-					
Gross value at point of production	\$52,110,030				
Operating expenses-					
Royalty	\$ 5,841,780				
Operation--basic facility	3,847,000				
Other operating expenses	4,130,000				
Intangible drilling costs	1,248,000				
Depreciation	8,530,000				
Taxes-					
Ad valorem	2,101,855				
Severance	4,915,437				
General overhead	1,023,960				
Total operating expenses	\$31,638,032				
Net income before interest	\$20,471,998	\$4,150,595*	\$ NONE	\$ 4,150,595*	\$10,881,931*
Less- Interest		512,455	-	212,216	2,165,064
Net income from Prudhoe Bay (A)		\$ 3,638,140	\$ NONE	\$ 3,938,379	\$ 8,716,867
TAPS (pipeline)-					
Tariff revenue	\$47,272,820				
Operating expenses-					
Operation	\$ 5,575,983				
Removal costs	1,007,040				
Depreciation	9,592,064				
Interest	8,274,240				
Ad valorem taxes	2,061,425				
Total operating expenses	\$26,510,752				
Net income from TAPS (B)	\$20,762,068	\$ 4,360,034*	\$ 3,288,712*	\$ 4,152,414*	\$ 6,932,073*
Net income from Prudhoe Bay Field and TAPS (A+B)		\$ 7,998,174	\$ 3,288,712	\$ 8,090,793	\$15,638,940
1976 worldwide net income before taxes x 24 years		\$25,833,576	\$72,768,000	\$187,944,000	\$ 4,625,563
Apportionment factor***					
Apportioned worldwide net income		\$ 596,330	\$ NONE	\$ 218,015	\$ NONE
Alaska taxable income--1978-2001		\$ 8,596,510	\$ 3,288,712	\$ 8,308,808	\$15,638,940
Alaska tax rate		x .094	x .094	x .094	x .094
Alaska income tax		\$ 776,112	\$ 309,137	\$ 731,028	\$ 1,470,000

* Apportioned according to ownership percentage.

** Proprietary information.

*** Apportionment factor for British Petroleum Company Limited

EXHIBIT VIII(b)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF CALIFORNIA TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field- Gross revenues	\$115,550,400				
Less- Royalty	6,016,613				
Net revenue	\$109,533,787				
Operating expenses- Operation--basic facility	\$ 3,967,000				
Other operating expenses***	5,452,000				
Depreciation	8,588,000				
Taxes- Ad valorem	2,501,306				
Severance	-				
Transportation	14,420,700				
TAPS tariff	47,523,360				
Total operating expenses	\$ 82,452,366				
Net income before interest	\$ 27,081,421	\$ 5,490,623*	\$ None *	\$ 5,490,623*	\$14,395,183*
Less- Interest		573,700			978,000
Net income from Prudhoe Bay (A)	\$ 4,911,813		\$ None	\$ 5,490,623	\$13,417,183
TAPS (pipeline)- Tariff revenue	\$ 47,523,360				
Operating expenses- Operation	\$ 1,677,269				
Removal costs	1,649,000				
Depreciation	6,064,650				
Interest	8,019,000				
Ad valorem taxes	1,693,550				
Total operating expenses	\$ 27,081,469				
Net income from TAPS (B)	\$ 20,441,891	\$ 4,309,175*	\$ 3,250,351*	\$ 4,103,974*	\$ 6,841,332*
Net income from Prudhoe Bay Field and TAPS (A + B)	\$ 14,921,649	\$ 8,808,848	\$ 6,740,702	\$ 9,594,597	\$20,258,515
1976 worldwide net income* before taxes x 25 years	20,902,475	75,800,000	195,775,000	4,821,425	
Total	146,130,735	\$79,650,351	\$255,369,601	\$25,079,940	
Apportionment factor****					
California taxable income	\$ 2,276,252	\$ 8,989,863	\$ 5,069,234	\$ 2,980,287	
California tax rate	x .09	x .09	x .09	x .09	
California income tax	\$ 204,863	\$ 809,088	\$ 510,231	\$ 268,706	

* Apportioned according to ownership percentage.

** Proprietary information.

*** Includes intangible drilling costs.

**** Apportionment factors for British Petroleum Company Limited and The Standard Oil Company are based on separate entity information for 1977 and combined group information for 1978 to 2001.

EXHIBIT VIII(c)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF KANSAS TAXABLE INCOME
FOR THE PERIOD 1977-2001
(In Thousands)

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field- Gross revenues	\$115,550,400				
Less- Royalty	5,929,733				
Net revenue	\$109,620,667				
Operating expenses- Operation--basic facility	\$ 3,967,000				
Other operating expenses***	5,452,000				
Depreciation	8,588,000				
Taxes- Ad valorem	4,366,100				
Severance	-				
Transportation	14,420,700				
TAPS tariff	48,218,400				
Total operating expenses	\$ 85,012,200				
Net income before interest and franchise tax	\$ 24,608,467	\$ 4,989,244*	\$ N/A	\$ 4,989,244*	\$13,090,650*
Less- Interest		578,790	N/A	-	978,000
Franchise tax		63	N/A	63	63
Net income from Prudhoe Bay (A)		\$ 4,410,391	\$ N/A	\$ 4,989,181	\$12,102,617
TAPS (pipeline)- Tariff revenue	\$ 48,218,400				
Operating expenses- Operation	\$ 5,677,267				
Removal costs	1,049,000				
Depreciation	9,964,650				
Interest	8,619,000				
Ad valorem taxes	2,763,850				
Total operating expenses	\$ 28,073,769				
Net income before franchise tax	\$ 30,144,631	\$ 4,230,173*	\$3,190,916*	\$ 4,028,926*	\$ 6,716,220*
Less- Franchise tax		63	63	63	63
Net income from TAPS (B)		\$ 4,230,110	\$3,190,847	\$ 4,028,863	\$ 6,716,157
Net income from Prudhoe Bay Field and TAPS (A + B)		\$ 8,640,501	\$3,190,847	\$ 9,018,044	\$18,818,774
1976 U.S. consolidated net income x 25 years		25,061,056	-	45,200,000	2,800,000
Total		\$33,701,557	\$3,190,847	\$54,218,044	\$21,618,774
Apportionment factor		**	**	**	**
Total Kansas taxable income		\$ 2,127,210	\$3,190,847	\$ 1,496,689	\$ 5,041,423
Kansas tax rate		x .0675	x .0675	x .0675	x .0675
Kansas income tax		\$ 141,317	\$ 212,704	\$ 101,027	\$ 339,046

* Apportioned according to ownership percentage.

** Proprietary information.

*** Includes intangible drilling costs.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF LOUISIANA TAXABLE INCOME

FOR THE PERIOD 1977-2001

(In Thousands)

	Total	Atlantic Richfield Company/ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/SOHIO Pipe Line Company
Prudhoe Bay Field- Gross revenues	\$115,550,400				
Less- Royalty	6,146,933				
Net revenue	\$109,403,467				
Operating expenses- Operation--basic facility	\$ 3,967,000				
Other operating expenses***	5,452,000				
Depreciation	8,588,000				
Taxes- Ad valorem	968,300				
Severance	5,739,661				
Transportation	14,420,700				
TAPS tariff	46,480,800				
General overhead	1,042,500				
Total operating expenses	\$ 86,659,021				
Net income before interest and franchise tax	\$ 22,744,446	\$4,611,323*	\$ N/A	\$4,611,323*	\$12,089,856*
Less- Interest		518,790	N/A		978,000
Franchise tax		8,400	N/A	9,850	20,800
Federal taxable income		\$4,024,133	\$ N/A	\$4,601,473	\$11,091,056
Less- Federal income tax		955,522	N/A	1,087,978	2,629,804
Depreciation		1,940,910	N/A	2,236,305	5,374,090
Louisiana taxable income--Prudhoe Bay (A)		\$1,127,701	\$ None	\$1,277,190	\$ 3,087,162
TAPS (pipeline)- Tariff revenue	\$ 46,480,800				
Operating expenses- Operation	\$ 5,677,269				
Accessorial costs	1,049,000				
Depreciation	9,964,650				
Interest	8,619,000				
Ad valorem taxes	1,210,350				
Total operating expenses	\$ 26,529,269				
Net income before franchise tax	\$ 19,951,531	\$4,183,822*	\$3,160,323*	\$3,990,306*	\$ 6,651,810*
Less- Franchise tax		49,775	46,000	49,850	94,825
Net income from TAPS		\$4,140,047	\$3,114,323	\$3,940,456	\$ 6,557,015
10% pipeline (separate entity) net income before taxes x 25 years		656,283		1,359,132	74,847
Total		\$4,796,330	\$3,114,323	\$5,339,588	\$ 6,631,862
Apportionment factor					
Income subject to Federal income tax		\$2,790,260	\$3,076,951	\$2,885,695	\$ 6,499,225
Less- Federal income tax		1,280,290	1,415,397	1,325,420	2,929,644
Louisiana taxable income--TAPS (B)		\$1,509,980	\$1,661,554	\$1,558,275	\$ 3,569,581
Louisiana taxable income (A + B)		\$2,637,681	\$1,661,554	\$2,835,465	\$ 6,650,643
Louisiana tax rate		.08	.08	.08	.08
Total income tax		\$ 210,914	\$ 132,924	\$ 226,837	\$ 529,739

* Apportioned according to ownership percentage.

** Proprietary Information.

*** Includes intangible drilling costs.

**COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF NEW MEXICO TAXABLE INCOME**

EXHIBIT VIII(-)
UNADJUSTED

FOR THE PERIOD 1977-2001

(In Thousands)

	Total	Atlantic Richfield Company/ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/SOHIO Pipe Line Company
Prudhoe Bay Field-					
Gross revenues	\$115,550,400				
Less- Royalty	6,168,602				
Net revenue	\$109,381,798				
Operating expenses-					
Operation--basic facility	\$ 3,967,000				
Other operating expenses***	5,452,000				
Depreciation	8,588,000				
Taxes-					
Ad valorem	151,675				
Severance	5,671,346				
Transportation	14,420,700				
TAPS tariff	46,307,040				
Total operating expenses	\$ 84,557,761				
Net income before interest and franchise tax	\$ 24,823,987	\$ 5,032,939*	? N/A	\$ 5,032,939*	\$13,192,240*
Less-					
Interest		578,790	N/A	-	976,000
Franchise tax		5,939	N/A	7,813	4,714
Net income from Prudhoe Bay		\$ 4,448,210	\$ N/A	\$ 5,025,126	\$12,211,526
1976 net income of separate entity holding title to Prudhoe Bay Field x 25 years		14,724,550	N/A	73,364,000	1,500,425
Total		\$19,172,760	\$ N/A	\$78,389,126	\$13,711,951
Apportionment factor		**	**	**	**
New Mexico taxable income--Prudhoe Bay (A)		\$ 1,307,884	\$ NONE	\$ 2,402,117	\$ 4,922,287
TAPS (pipeline)-					
Tariff revenue	\$ 46,307,040				
Operating expenses-					
Operation	\$ 5,677,269				
Removal costs	1,049,600				
Depreciation	9,904,650				
Interest	2,619,000				
Ad valorem taxes	1,171,000				
Total operating expenses	\$ 20,420,919				
Net income before franchise tax	\$ 19,826,121	\$ 4,163,485*	\$3,140,453*	\$ 3,965,224*	\$ 6,610,029*
Less- Franchise tax		2,790	3,240	2,745	2,280
Net income from TAPS		\$ 4,160,695	\$3,137,213	\$ 3,962,479	\$ 6,607,749
1976 pipeline (separate entity) net income before taxes x 25 years		690,283	-	1,399,112	74,247
Total		\$ 4,850,978	\$3,137,213	\$ 5,361,611	\$ 6,681,996
Apportionment factor		**	**	**	**
New Mexico taxable income--TAPS (B)		\$ 2,808,298	\$3,099,571	\$ 3,897,597	\$ 6,443,344
Total New Mexico taxable income (A + B)		\$ 4,016,182	\$3,099,571	\$ 6,299,714	\$11,451,331
New Mexico tax rate		x .01	x .01	x .01	x .01
New Mexico income tax		\$ 200,809	\$ 124,977	\$ 264,980	\$ 773,100

* Apportioned according to ownership percentage.

** Proprietary information.

*** Includes intangible drilling costs.

EXHIBIT

A-64

**COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF OKLAHOMA TAXABLE INCOME**

**EXHIBIT VIII(2)
NONINFLATED**

FOR THE PERIOD 1977-2001

(In Thousands)

	Total	Atlantic Richfield Company/ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/SOHIO Pipe Line Company
Prudhoe Bay Field-					
Gross revenues	\$115,550,400				
Less- Royalty	5,962,313				
Net revenue	\$109,588,087				
Operating expenses-					
Operation--basic facility	\$ 3,967,000				
Other operating expenses***	5,452,000				
Depreciation	8,588,000				
Taxes-					
Ad valorem	526,050				
Severance	3,256,781				
Transportation	14,420,700				
TAPS tariff	47,957,760				
General overhead	1,042,560				
Total operating expenses	\$ 85,210,851				
Net income before interest, franchise tax, and depletion	\$ 24,377,236	\$4,942,363*	\$ N/A	\$ 4,942,363*	\$12,957,769*
Less-					
Interest		578,790	N/A	-	978,000
Franchise tax		500	N/A	500	500
Depletion		2,075,216	N/A	2,075,216	5,440,753
Oklahoma taxable income--Prudhoe Bay (A)	\$2,287,817	\$2,287,817	\$ NONE	\$ 2,866,647	\$ 6,533,516
TAPS (pipeline)-					
Tariff revenue	\$ 47,957,760				
Operating expenses-					
Operation	\$ 5,677,269				
Removal costs	1,049,000				
Depreciation	9,904,650				
Interests	8,619,000				
Ad valorem taxes	3,048,375				
Total operating expenses	\$ 28,308,294				
Net income before franchise taxes-	\$ 19,599,466	\$4,115,688*	\$3,104,515*	\$ 3,919,893*	\$ 6,534,462*
Less- Franchise tax		500	500	500	500
Net income from TAPS	\$4,115,388	\$4,115,388	\$3,104,015	\$ 3,919,393	\$ 6,533,962
1976 pipeline (separate entity) net income before taxes x 25 years		656,283	-	1,399,132	74,847
Total	\$4,771,671	\$4,771,671	\$3,104,015	\$ 5,318,525	\$ 6,608,809
Apportionment factor		**	**	**	**
Oklahoma taxable income--TAPS (B)	\$2,781,884	\$2,781,884	\$3,066,806	\$ 2,874,312	\$ 6,426,633
Total Oklahoma taxable income (A + B)	\$5,069,741	\$5,069,741	\$6,170,821	\$ 5,740,959	\$13,160,149
Oklahoma tax rate	x .0384	x .0384	x .0384	x .0384	x .0384
Oklahoma income tax	\$ 194,678	\$ 194,678	\$ 237,267	\$ 220,262	\$ 505,387

* Apportioned according to ownership percentage.

** Proprietary information.

*** Includes intangible drilling costs.

EXHIBIT

A-65

EXHIBIT IX
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

FRANCHISE TAX SUMMARY

(In Thousands)

		Atlantic Richfield Company/ ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/SOHIO Pipe Line Company	Total
Kansas*- Prudhoe Bay Pipeline		\$ 63 63	\$ N/A 63	\$ 63 63	\$ 63 63	\$ 189 252
Total		\$ 126 =====	\$ 63 =====	\$ 126 =====	\$ 126 =====	\$ 441 =====
Louisiana- Prudhoe Bay Pipeline	IX(a)	\$ 8,400	\$ N/A	\$ 9,850	\$ 20,800	\$ 39,050
	IX(a)	49,775	46,000	49,850	94,825	240,450
Total		\$58,175 =====	\$46,000 =====	\$59,700 =====	\$115,625 =====	\$279,500 =====
New Mexico- Prudhoe Bay Pipeline	IX(b)	\$ 5,939	\$ N/A	\$ 7,813	\$ 4,714	\$ 18,466
	IX(b)	2,790	3,240	2,745	2,280	11,055
Total		\$ 8,729 =====	\$ 3,240 =====	\$10,558 =====	\$ 6,994 =====	\$ 29,521 =====
Oklahoma***- Prudhoe Bay Pipeline		\$ 500 500	\$ N/A 500	\$ 500 500	\$ 500 500	\$ 1,500 2,000
Total		\$ 1,000 =====	\$ 500 =====	\$ 1,000 =====	\$ 1,000 =====	\$ 3,500 =====
Texas- Prudhoe Bay Pipeline***	IX(c)	\$54,950	\$ N/A	\$54,950	\$144,025	\$253,925
	IX(c)	34,000	27,200	32,400	54,000	147,600
Total		\$88,950 =====	\$27,200 =====	\$87,350 =====	\$198,025 =====	\$401,525 =====
Wyoming- Prudhoe Bay Pipeline	IX(e)	\$ 575	\$ N/A	\$ 575	\$ 1,525	\$ 2,675
	IX(e)	250	200	250	400	1,100
Total		\$ 825 =====	\$ 200 =====	\$ 825 =====	\$ 1,925 =====	\$ 3,775 =====

* Assumed maximum franchise tax of \$2,500 per year for each company.

** Assumed maximum franchise tax of \$20,000 per year for each company.

*** Includes intangible tax on pipeline.

EXHIBIT

A-66

EXHIBIT IX(a)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF LOUISIANA FRANCHISE TAX
(In Thousands)

	Prudhoe Bay				TAPS			
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Apportioned equity and borrowed capital-								
Equity	\$	* \$ N/A	\$13,788,472	\$	* \$ 236,832	\$ 245,667	\$ 258,922	\$ 171,220
Borrowed capital		* N/A	3,214,078		* 1,287,766	986,576	1,356,374	2,468,112
Total	\$	\$ NONE	\$17,002,550	\$	\$1,524,598	\$1,232,243	\$1,615,296	\$2,639,332
Apportionment factor		* N/A			*	*	*	*
Apportioned capital (A)	\$223,998	\$ NONE	\$ 262,587	\$554,472	\$1,327,239	\$1,226,513	\$1,329,597	\$2,528,865
Assessed valuation--total assessed property located in state (B)	\$130,879	\$ N/A	\$ 130,879	\$343,135	\$ 170,709	\$ 128,763	\$ 162,580	\$ 271,021
Greater of (A) or (B)	\$223,998	\$ NONE	\$ 262,587	\$554,472	\$1,327,239	\$1,226,513	\$1,329,597	\$2,528,865
Tax rate	x .0015	N/A	x .0015	x .0015	x .0015	x .0015	x .0015	x .0015
Franchise tax--1 year	\$ 336	\$ NONE	\$ 394	\$ 832	\$ 1,991	\$ 1,840	\$ 1,994	\$ 3,793
Franchise tax--25 years	\$ 8,400	\$ NONE	\$ 9,850	\$ 20,800	\$ 49,775	\$ 46,000	\$ 49,850	\$ 94,825

* Proprietary information.

EXHIBIT IX(b)
NON INFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF NEW MEXICO FRANCHISE TAX

(In Thousands)

	Prudhoe Bay				TAPS			
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Equity**	\$ *	\$ N/A	\$ *	\$ *	\$ *	\$ *	\$ *	\$ *
Apportionment factor	*	N/A	*	*	*	*	*	*
Apportioned equity	\$447,476	\$ NONE	\$586,876	\$352,491	\$209,455	\$244,616	\$207,315	\$172,515
Tax rate	x.00055	N/A	x.00055	x.00055	x.00055	x.00055	x.00055	x.00055
Franchise tax--Each year after 1977	\$ 246	\$ NONE	\$ 323	\$ 194	\$ 115	\$ 135	\$ 114	\$ 95
Franchise tax--1978-2001	\$ 5,904	\$ NONE	\$ 7,752	\$ 4,656	\$ 2,760	\$ 3,240	\$ 2,736	\$ 2,280
Franchise tax--1977	\$ 35	\$ NONE	\$ 61	\$ 58	\$ 30	\$ -	\$ 9	\$ -
Franchise tax--25 years	\$ 5,939	\$ NONE	\$ 7,813	\$ 4,714	\$ 2,790	\$ 3,240	\$ 2,745	\$ 2,280

* Proprietary information.

** Franchise tax base is capital stock for 1977 and equity for 1978 to 2001.

EXHIBIT 1X(e)
NOT INFLATED

COMPARATIVE STATE TAX BURDEN STUDY

CALCULATION OF TEXAS FRANCHISE TAX

(In Thousands)

	Prudhoe Bay				TAPS			
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Apportioned equity and borrowed capital- Equity	\$ N/A *	\$ N/A	\$ N/A *	\$ N/A *	\$ N/A *	\$ N/A *	\$ N/A *	\$ N/A *
Borrowed capital	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Apportionment factor	\$ *	\$ NONE N/A *	\$ *	\$ *	\$ *	\$ *	\$ *	\$ *
Apportioned capital (A)	\$ NONE	\$ NONE	\$ 20,889	\$ 83,216	\$ 207,076	\$ 250,787	\$ 207,569	\$ 178,519
Assessed valuation--total county assessed property located in state (B)	\$517,072	\$ N/A	\$517,072	\$1,355,647	\$235,864	\$177,909	\$224,632	\$374,462
Greater of (A) or (B)	\$517,072	\$ NONE	\$517,072	\$1,355,647	\$235,864	\$250,787	\$224,632	\$374,462
Tax rate	x .00425	N/A	x .00425	x .00425	x .00425	x .00425	x .00425	x .00425
Franchise tax before reductions	\$ 2,198	\$ NONE	\$ 2,198	\$ 5,761	\$ 1,002	\$ 1,066	\$ 955	\$ 1,591
80% reduction of franchise tax due to taxation of intangibles	N/A	N/A	N/A	N/A	(802)	(853)	(764)	(1,273)
Total franchise tax liability	\$ 2,198	\$ NONE	\$ 2,198	\$ 5,761	\$ 200	\$ 213	\$ 191	\$ 318
Intangibles tax on pipeline (Exhibit 1X(d))	N/A	N/A	N/A	N/A	1,160	875	1,105	1,842
Total franchise and intangibles tax- 1 year	\$ 2,198	\$ NONE	\$ 2,198	\$ 5,761	\$ 1,360	\$ 1,088	\$ 1,296	\$ 2,160
Total franchise and intangibles tax--25 years	\$ 54,950	\$ NONE	\$ 54,950	\$ 144,025	\$ 34,000	\$ 27,200	\$ 32,400	\$ 54,000

* Proprietary information.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF TEXAS INTANGIBLES TAX ON PIPELINE
(In Thousands)

	ARCO	BP Pipelines, Inc.	Exxon	SOHIO
Net operating income*	\$ 84,840	\$ 63,994	\$ 80,800	\$ 134,694
Capitalization rate	+ .07	+ .07	+ .07	+ .07
Valuation	\$1,212,000	\$ 914,200	\$1,154,286	\$ 1,924,200
Less- Average depreciated book value	840,673	634,107	800,641	1,334,668
Total value subject to assessment	\$ 371,327	\$ 280,093	\$ 353,645	\$ 589,532
Average assessment rate	x .25	x .25	x .25	x .25
Taxable value	\$ 92,832	\$ 70,023	\$ 88,411	\$ 147,383
Tax rate	x .0125	x .0125	x .0125	x .0125
Intangibles tax--1 year	\$ 1,160	\$ 875	\$ 1,105	\$ 1,842
Intangibles tax--25 years	\$ 29,000	\$ 21,875	\$ 27,625	\$ 46,050

* Twenty-five year average return on investment
from TAPS tariff computation apportioned
according to ownership percentages.

EXHIBIT IX(c)
NONINFLATED

COMPARATIVE STATE TAX BURDEN STUDY

CALCULATION OF WYOMING FRANCHISE TAX

(In Thousands)

Prudhoe Bay

TAPS

Assessed valuation-
Total assessed property
located in state
Tax rate

Franchise tax--1 year

Franchise tax--25 years

Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
\$462,248 x .00005 -----	\$ N/A N/A -----	\$462,248 x .00005 -----	\$1,211,912 x .00005 -----	\$201,600 x .00005 -----	\$152,064 x .00005 -----	\$192,000 x .00005 -----	\$320,064 x .00005 -----
\$ 23 =====	\$ NONE =====	\$ 23 =====	\$ 61 =====	\$ 10 =====	\$ 8 =====	\$ 10 =====	\$ 16 =====
\$ 575 =====	\$ NONE =====	\$ 575 =====	\$ 1,525 =====	\$ 250 =====	\$ 200 =====	\$ 250 =====	\$ 400 =====

EXHIBIT X
INFLATED

COMPARATIVE STATE TAX BURDEN STUDY

SUMMARY OF TOTAL TAXES

(In Thousands)

<u>Rank</u>	<u>State</u>	<u>Exhibit</u>	<u>Ad Valorem Tax</u>	<u>Severance Tax</u>	<u>Income Tax</u>	<u>Franchise Tax</u>	<u>Total Tax</u>	<u>Percentage of Each State To Alaska</u>
1	Alaska	XIII	\$4,755,822	\$6,267,351	\$4,589,010	\$ N/A	\$15,612,183	100%
2	Louisiana	XIII	2,390,333	7,652,750	1,425,861	282,725	11,751,669	75
3	Wyoming	XIII	7,093,157	2,554,307	N/A	5,800	9,653,264	62
4	New Mexico	XIII	1,261,930	6,808,260	1,441,079	31,105	9,542,374	61
5	Oklahoma	XIII	3,728,358	4,305,485	1,394,446	3,500	9,431,789	60
6	Kansas	XIII	8,346,451	N/A	1,049,817	441	9,396,709	60
7	Texas	XIII	4,983,170	2,927,622	N/A	574,725*	8,485,517	54
8	California	XIII	4,574,999	N/A	1,913,530	N/A	6,488,529	42

* Includes intangibles tax on pipeline.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF WELLHEAD VALUE OF PRODUCED OIL
 (Per barrel)

EXHIBIT #1
 16-1111

	Alaska		California		Kansas		Louisiana		New Mexico		Oklahoma		Texas		Wyoming	
	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001	1977-1979	1980-2001
Market price at destination (A)	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65	\$14.57	\$17.65
TARS tariff (B)	6.45	6.45	6.35	6.35	6.46	6.46	6.22	6.22	6.18	6.18	6.43	6.43	6.13	6.13	6.10	6.10
Tanker Vailed to California (C)	1.06	1.47	1.06	1.47	1.06	1.47	1.06	1.47	1.06	1.47	1.06	1.47	1.06	1.47	1.06	1.47
Tanker California to Gulf Coast (D)	2.74	-	2.74	-	2.74	-	2.74	-	2.74	-	2.74	-	2.74	-	2.74	-
Pipeline California to Midcontinent (E)	-	1.77	-	1.77	-	1.77	-	1.77	-	1.77	-	1.77	-	1.77	-	1.77
Oil destination: California (F)	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%	57-1/2%
Gulf Coast (F)	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%	42-1/2%
Weighted average--without value (ump Station #1)	5.90	8.98	6.00	9.08	5.89	8.97	6.13	9.21	6.17	9.25	5.92	9.00	6.22	9.30	6.21	9.33
Weighted average--clean field cost (G)	.63	.96	.69	.96	.69	.96	.69	.96	.69	.96	.69	.96	.69	.96	.69	.96
Royalty value	5.21	8.02	5.31	8.12	5.20	8.01	5.44	8.25	5.48	8.29	5.23	8.04	5.53	8.34	5.56	8.37

(A) \$13.10 per barrel inflated to 1982 at a rate consistent with that utilized in Fritchard & Abbott's Engineering Survey of Sadlerochit Oil Pool Unit Area, Table #7 and weighted according to annual volume of production.

(B) See Exhibit XII.

(C) Average of tanker cost to West Coast per June, 1977, royalty reports submitted to State of Alaska except July, 1977, royalty report by Exxon inflated by nine percent annually through 1982.

(D) Approximate incremental cost to SOHIO of transportation costs to the Gulf Coast per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon, inflated by nine percent through 1982.

(E) Assumes that a pipeline would be available on January 1, 1980, to move oil from California to Mid-continent. Tariff of \$1.50 per barrel obtained from Federal Energy Administration's Alaska North Slope Crude Oil Pricing on Estimation, Treatment, 42 Fed. Reg. 13,199 (1977), inflated by nine percent annually through 1982.

(F) Allocation based on Federal Energy Administration estimate that approximately 35-50 percent of production will be supplied to Gulf Coast, 42 Fed. Reg. 13,199 (1977).

(G) Weighted average per June, 1977, royalty reports submitted to State of Alaska, except July, 1977, royalty report by Exxon inflated by nine percent annually through 1982.

EXHIBIT XII
INFLATED

COMPARATIVE STATE TAX BURDEN STUDY

TAPS TARIFF DETERMINATION

1977 - 2001

(In Thousands)

		Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Oil spill funds	(A)	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000	\$ 100,000
Operation and maintenance	(B)	9,088,828	9,088,828	9,088,828	9,088,828	9,088,828	9,088,828	9,088,828	9,088,828
Depreciation	(C)	10,014,650	10,014,650	10,014,650	10,014,650	10,014,650	10,014,650	10,014,650	10,014,650
Interest	(D)	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000	8,619,000
State taxes	(E)	4,626,204	3,786,866	4,722,352	2,618,689	2,280,451	4,415,664	1,865,300	1,563,650
Dismantling costs	(F)	1,542,337	1,542,337	1,542,337	1,542,337	1,542,337	1,542,337	1,542,337	1,542,337
Federal income tax	(G)	10,175,248	10,175,248	10,175,248	10,175,248	10,175,248	10,175,248	10,175,248	10,175,248
Return on investment	(H)	11,865,490	11,865,490	11,865,490	11,865,490	11,865,490	11,865,490	11,865,490	11,865,490
Total		\$56,031,757	\$55,192,419	\$56,127,902	\$54,024,242	\$53,686,004	\$55,821,217	\$53,270,853	\$52,969,203
Throughput (25 years) (barrels)		8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000
Average tariff rate		\$6.45	\$6.35	\$6.46	\$6.22	\$6.18	\$6.43	\$6.13	\$6.10

(A) Estimate furnished by owner companies.

(B) \$.938 per barrel less ad valorem tax component inflated by nine percent annually through 1982.

(C) Recover entire cost from Interstate Commerce Commission order plus inflated Phase III expansion.

(D) 8.582 percent interest rate, principal of \$8,034,480 paid on linear basis.

(E) Maximum state rate applied to sum of (G) and (H) plus ad valorem tax and franchise tax.

(F) \$41.96 million per year for 25 years inflated by nine percent annually through 1982.

(G) 49/52 applied to (H) for 1977 and 1978; 46/54 applied to (H) after 1978.

(H) 7.0 percent of total outstanding valuation for 25 years (\$169,507,000).

COMPARATIVE STATE TAX BURDEN STUDY

EXHIBIT XIII
INFLATED

SUMMARY OF TOTAL TAXES BY MAJOR OWNERS

(In Thousands)

	Exhibit Subsidiaries					Total				
	Atlantic Richfield Company and/or	British Petroleum Company Limited and/or	Exxon Corporation and/or	The Standard Oil Company of Ohio and/or						
Alaska tax-										
Ad valorem	XIV \$1,067,013	\$ 404,613	\$1,041,469	\$2,242,727	\$ 4,755,822					
Severance	XV 1,356,048	N/A	1,356,048	3,555,255	6,267,351					
Income	XVI 1,052,081	361,643	1,053,682	2,121,604	4,589,010					
Franchise	N/A	N/A	N/A	N/A	NONE					
Total	\$3,475,142	\$766,256	\$3,451,199	\$7,919,586	\$15,612,183					
California tax-										
Ad valorem	XIV \$1,019,826	\$ 318,785	\$ 999,700	\$2,236,688	\$ 4,574,999					
Severance	XV N/A	N/A	N/A	N/A	NONE					
Income	XVI 224,257	814,972	518,638	355,663	1,913,530					
Franchise	N/A	N/A	N/A	N/A	NONE					
Total	\$1,244,083	\$1,133,757	\$1,519,338	\$2,592,351	\$6,488,529					
Kansas tax-										
Ad valorem	XIV \$1,854,025	\$ 512,321	\$1,821,681	\$4,158,424	\$ 8,346,451					
Severance	XV N/A	N/A	N/A	N/A	NONE					
Income	XVI 156,415	250,063	106,700	536,639	1,049,817					
Franchise	XVII 126	63	126	126	421					
Total	\$2,010,566	\$762,447	\$1,928,507	\$4,695,189	\$9,396,709					
Louisiana tax-										
Ad valorem	XIV \$ 538,422	\$ 226,025	\$ 524,153	\$1,101,733	\$ 2,390,333					
Severance	XV 1,655,803	N/A	1,655,803	4,341,144	7,652,750					
Income	XVI 276,718	156,186	290,891	702,066	1,425,861					
Franchise	XVII 59,675	46,375	60,125	117,550	283,725					
Total	\$2,529,618	\$ 428,586	\$2,530,972	\$6,262,493	\$11,751,669					
New Mexico tax-										
Ad valorem	XIV \$ 290,561	\$ 186,508	\$ 278,786	\$ 506,075	\$ 1,261,930					
Severance	XV 1,473,083	N/A	1,473,083	3,862,034	6,808,240					
Income	XVI 229,563	182,179	287,393	741,924	1,441,079					
Franchise	XVII 8,969	3,360	10,726	8,050	31,105					
Total	\$3,002,176	\$ 371,997	\$2,049,939	\$5,118,213	\$9,542,374					

EXHIBIT

A-75

EXHIBIT XIII
INFLATED
(Continued)

-2-

		Atlantic Richfield Company and/or Subsidiaries	British Petroleum Company Limited and/or Subsidiaries	Exxon Corporation and/or Subsidiaries	The Standard Oil Company of Ohio and/or Subsidiaries	Total
Oklahoma tax- Ad valorem Severance Income Franchise	XIV XV XVI XVII	\$ 859,776 931,565 268,677 1,000	\$ 565,060 N/A 133,674 500	\$ 824,103 931,565 292,536 1,000	\$1,479,419 2,442,355 694,559 1,000	\$ 3,728,358 4,305,485 1,394,446 3,500
Total		\$2,061,018	\$ 704,234	\$2,049,204	\$4,617,333	\$ 9,431,789
Texas tax- Ad valorem Severance Income Franchise*	XIV XV XVII	\$1,102,282 633,441 N/A 128,075	\$ 259,610 N/A N/A 39,750	\$1,086,192 633,441 N/A 125,575	\$2,534,786 1,660,740 N/A 281,325	\$ 4,983,170 2,927,622 NONE 574,725
Total		\$1,864,098	\$ 299,360	\$1,845,208	\$4,476,851	\$ 8,485,517
Wyoming tax- Ad valorem Severance Income Franchise	XIV XV XVII	\$1,557,977 552,668 N/A 1,275	\$ 247,508 N/A N/A 200	\$1,542,351 552,668 N/A 1,275	\$3,745,321 1,448,971 N/A 3,050	\$ 7,093,157 2,554,307 NONE 5,800
Total		\$2,111,920	\$ 247,708	\$2,096,294	\$5,197,342	\$ 9,653,264

* Includes intangibles tax on pipeline.

EXHIBIT XIV
INFLATED

COMPARATIVE STATE TAX BURDEN STUDY

AD VALOREM TAX SUMMARY

(In Thousands)

	Exhibit	Atlantic Richfield Company/ ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/ SOHIO Pipe Line Company	Total
Alaska-						
Pipeline	XIV(a)	\$ 536,419	\$404,613	\$ 510,875	\$ 851,629	\$2,303,536
Prudhoe Bay Field hardware	XIV(b)	530,594	N/A	530,594	1,391,098	2,452,286
Prudhoe Bay reserves	XIV(c)	N/A	N/A	N/A	N/A	N/A
Total		\$1,067,013	\$404,613	\$1,041,469	\$2,242,727	\$4,755,822
California-						
Pipeline	XIV(a)	\$ 422,632	\$318,785	\$ 402,506	\$ 670,978	\$1,814,901
Prudhoe Bay Field hardware	XIV(b)	112,366	N/A	112,366	294,599	519,331
Prudhoe Bay reserves	XIV(c)	484,828	N/A	484,828	1,271,111	2,240,767
Total		\$1,019,826	\$318,785	\$ 999,700	\$2,236,688	\$4,574,999
Kansas-						
Pipeline	XIV(a)	\$ 679,214	\$512,321	\$ 646,870	\$1,078,332	\$2,916,737
Prudhoe Bay Field hardware	XIV(b)	440,043	N/A	440,043	1,153,694	2,033,780
Prudhoe Bay reserves	XIV(c)	734,768	N/A	734,768	1,926,398	3,375,934
Total		\$1,854,025	\$512,321	\$1,821,681	\$4,158,424	\$8,346,451
Louisiana-						
Pipeline	XIV(a)	\$ 299,654	\$226,025	\$ 285,385	\$ 475,737	\$1,286,801
Prudhoe Bay Field hardware	XIV(b)	238,768	N/A	238,768	625,996	1,103,532
Prudhoe Bay reserves	XIV(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 538,422	\$226,025	\$ 524,153	\$1,101,733	\$2,390,333
New Mexico-						
Pipeline	XIV(a)	\$ 247,265	\$186,508	\$ 235,490	\$ 392,562	\$1,061,825
Prudhoe Bay Field hardware	XIV(b)	43,296	N/A	43,296	113,513	200,105
Prudhoe Bay reserves	XIV(c)	N/A	N/A	N/A	N/A	NONE
Total		\$ 290,561	\$186,508	\$ 278,786	\$ 506,075	\$1,261,930

EXHIBIT XIV
INFLATED
(Continued)

-2-

Exhibit	Company	Atlantic Richfield Company/ ARCO		BP Pipelines, Inc.		Exxon Corporation/ Exxon		SOHIO Petroleum Company/ SOHIO		Total
		Pipe Line	Company	Pipe Line	Company	Pipe Line	Company	Pipe Line	Company	
Oklahoma- Pipeline Prudhoe Bay Field hardware Prudhoe Bay reserves	XIV(a)	\$ 749,133		\$565,060		\$ 713,460		\$1,189,338		\$3,216,991
	XIV(b)	110,643		N/A		110,643		290,081		511,367
	XIV(c)	N/A		N/A		N/A		N/A		NONE
	Total	\$ 859,776		\$565,060		\$ 824,103		\$1,479,419		\$3,728,358
Texas- Pipeline Prudhoe Bay Field hardware Prudhoe Bay reserves	XIV(a)	\$ 344,180		\$259,610		\$ 327,790		\$ 546,426		\$1,478,006
	XIV(b)	351,602		N/A		351,602		921,822		1,625,026
	XIV(c)	406,800		N/A		406,800		1,066,538		1,880,138
	Total	\$1,102,582		\$259,610		\$1,086,192		\$2,534,786		\$4,983,170
Wyoming- Pipeline Prudhoe Bay Field hardware Prudhoe Bay reserves	XIV(a)	\$ 328,136		\$247,508		\$ 312,510		\$ 520,954		\$1,409,103
	XIV(b)	335,208		N/A		335,208		878,841		1,549,257
	XIV(c)	894,633		N/A		894,633		2,345,526		4,134,792
	Total	\$1,557,977		\$247,508		\$1,542,351		\$3,745,321		\$7,093,157

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF AD VALOREM TAX ON PIPELINE
(In Thousands)

	Percentage Ownership in TAPS	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Average outstanding historical cost		\$ N/A	\$ N/A	\$ N/A	\$ N/A	\$8,044,000	\$ N/A	\$8,044,000	\$8,044,000
Unit appraisal valuation		8,716,000	10,349,600	10,349,600	10,349,600	N/A	10,349,600	N/A	N/A
Modifications to unit appraisal valuation		N/A	(631,000)	(631,000)	(631,000)	N/A	(631,000)	N/A	N/A
100% valuation		\$ 8,716,000	\$ 9,718,600	\$ 9,718,600	\$ 9,718,600	\$8,044,000	\$ 9,718,600	\$8,044,000	\$8,044,000
Average life rate		N/A	N/A	N/A	N/A	x .50***	N/A	x .50***	x .48****
Average of annual decline rate		x .5861346	x .5729248 **	x .6525502**	x .6525502**	N/A	x .6525502**	N/A	N/A
Average assessment ratio		\$ 5,108,749 x 1.00	\$ 5,568,027 x .25	\$ 6,341,874 x .30	\$ 6,341,874 x .15	\$4,022,000 x .33-1/3	\$ 6,341,874 x .30	\$4,022,000 x .418	\$3,861,120 x .25
Assessed value of property		\$ 5,108,749	\$ 1,392,007	\$ 1,902,562	\$ 951,281	\$1,340,667	\$ 1,902,562	\$1,681,196	\$ 965,280
Tax rate		x .02	x .05	x .068	x .06	x .03513	x .075	x .0389951	x .06475
Tax for 100% ownership--1 year		\$ 102,175	\$ 69,600	\$ 129,374	\$ 57,077	\$ 47,098	\$ 142,692	\$ 65,558	\$ 62,502
Tax for 100% ownership--25 years		\$ 2,554,375	\$ 2,012,531 *****	\$ 3,234,350	\$ 1,426,925	\$1,177,450	\$ 3,567,300	\$1,638,950	\$1,562,550
ARCO Pipe Line Company	21.0	\$ 536,419	\$ 422,632	\$ 679,214	\$ 299,654	\$ 247,265	\$ 749,133	\$ 344,180	\$ 328,136
BP Pipeline, Inc.	15.84	404,613	318,785	512,321	226,025	186,508	565,060	259,610	247,508
Exxon Pipe Line Company	20.0	510,875	402,506	646,870	285,385	235,450	713,460	327,790	312,510
SCHL Pipe Line Company	33.34	851,629	670,978	1,078,332	475,737	392,562	1,189,338	546,426	520,954
Total		\$ 2,303,536	\$ 1,814,901	\$ 2,915,737	\$ 1,286,801	\$1,061,825	\$ 3,216,991	\$1,478,006	\$1,409,108

* Provision for an approximate 2.5 percent annual decline rate through 1996; a decline of 64.79 percent in 1997 is provided for in order to reach a depreciated historical cost valuation. Such a reduction would be reasonable upon a showing by the taxpayer that the economic life of the proven reserves is materially shorter than that of the pipeline.

** Provision for an approximate 2.5 percent annual decline rate.

*** Negative salvage assumed.

**** Index of 1967 costs per Wyoming Department of Revenue.

***** Tax attributable to the period preceding July 1, 1978, is computed utilizing the pre-Proposition 13 tax rate of .119.

COMPARATIVE STATE TAX BURDEN STUDY

CALCULATION OF AD VALOREM TAX ON PRUDHOE HAY FIELD HARDWARE

(In Thousands)

	Percentage Ownership in Prudhoe Field	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
100% valuation		\$5,234,080**	\$4,030,727***	\$6,511,480**	\$5,234,080**	\$729,432****	\$970,160**	\$8,511,480**	\$8,511,480**
Index to 1967 costs--Wyoming		N/A	N/A	N/A	N/A	N/A	N/A	N/A	x .48
Average life rate		N/A	N/A	x .50*		N/A	N/A	x .50*	N/A
		\$5,234,080	\$4,030,727	\$4,255,740	\$5,234,080	\$729,432	\$970,160	\$4,255,740	\$4,085,510
Average assessment ratio		x 1.00	x .25	x .30	x .15	x .33-1/3	x .30	x .418	x .25
Assessed value of property		\$5,234,080	\$1,007,682	\$1,276,722	\$ 785,112	\$243,144	\$291,048	\$1,778,899	\$1,021,378
Tax rate		x .02	x .05	x .068	x .060	x .03513	x .075	x .0389951	x .06475
Fax for 100% ownership--1 year		\$ 104,682	\$ 50,384	\$ 86,817	\$ 47,107	8,542	\$ 21,829	\$ 69,368	\$ 66,134
Fax for 100% ownership--25 years		\$2,617,050	\$ 554,224***	\$2,170,425	\$1,177,675	\$213,550	\$545,725	\$1,734,208	\$1,653,350
Atlantic Richfield Company	20.2745	\$ 530,594	\$ 112,366	\$ 440,043	\$ 238,768	\$ 43,296	\$110,643	\$ 351,602	\$ 335,208
Exxon Corporation	20.2745	530,594	112,366	440,043	238,768	43,296	110,643	351,602	335,208
Conoco Petroleum Company	53.1552	1,391,094	294,599	1,153,694	625,996	113,513	290,081	921,822	878,841
		\$2,452,286	\$ 519,331	\$2,033,780	\$1,103,532	\$200,105	\$511,367	\$1,625,026	\$1,549,257

* Negative salvage assumed.

** For Alaska, Louisiana, and Oklahoma, used 25-year average of inflated hardware tax value base from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6. However, Oklahoma is exclusive of production equipment. Kansas, Texas, and Wyoming are based on a 25-year average of cumulative inflated capital expenditures from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6.

*** Valuation is based on a 11-year average of inflated hardware tax value base, limited to two percent annual inflation, from Pritchard & Abbott Engineering Survey of Prudhoe Bay Sadlerochit Pool Unit Area, Table 6 (1991-2001), during which period the ad valorem tax on Prudhoe Bay Field equipment exceeds tax on Prudhoe Bay oil reserves. See Exhibit XIV(c).

**** Valuation is based on a 25-year average of gross production net of royalty multiplied by taxable value factor of 27 percent.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF AD VALOREM TAX ON OIL RESERVES
(In Thousands)

	Percentage Ownership in Reserves	Alaska	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Valuation		\$ N/A	\$11,595,840	\$7,106,072	\$ N/A	\$ N/A	\$ N/A	\$12,462,133	\$2,725,925
Modification to Texas valuation for field hardware offset		N/A	N/A	N/A	N/A	N/A	N/A	(4,255,729)	N/A
Valuation as modified		\$ N/A	\$11,595,840	\$7,106,072	\$ N/A	\$ N/A	\$ N/A	\$ 8,206,404	\$2,725,925
Average assessment ratio		N/A	x .25	x .30	N/A	N/A	N/A	x .418	x 1.00
Assessed value		\$ N/A	\$ 2,898,960	\$2,131,822	\$ N/A	\$ N/A	\$ N/A	\$ 3,430,277	\$2,725,925
Average tax rate		N/A	x .05	x .063	N/A	N/A	N/A	x .0389951	x .06475
Tax for 100% ownership--1 year		\$ NONE	\$ 144,948	144,964	\$ NONE	\$ NONE	\$ NONE	\$ 133,764	\$ 176,504
Tax for 100% ownership--25 years		\$ NONE	\$ 2,391,318	\$1,624,100	\$ NONE	\$ NONE	\$ NONE	\$ 2,006,460	\$1,412,600
Atlantic Richfield Company	20.2745	\$ N/A	\$ 484,828	\$ 734,768	\$ N/A	\$ N/A	\$ N/A	\$ 406,800	\$ 894,633
Exxon Corporation	20.2745	N/A	484,828	734,768	N/A	N/A	N/A	406,800	894,633
SOHIO Petroleum Company	53.1552	N/A	1,271,111	1,926,398	N/A	N/A	N/A	1,066,538	2,345,526
		\$ NONE	\$ 2,240,767	\$3,395,934	\$ NONE	\$ NONE	\$ NONE	\$ 1,880,138	\$4,134,792

* Tax for the period January 1, 1977, to June 30, 1978, is based on pre-Proposition 13 law, the valuation is based on a 12-1/2 year average (July 1, 1978-1990). During the 14-year period (1977-1990), the reserves valuation exceeds that of the hardware; however, beginning in 1991 and thereafter, the reserves tax is inapplicable as the hardware valuation exceeds that of reserves. See Exhibit XIV(b).

** Valuation is based on a 15-year average (1977-1991), during which period reserves valuation exceeds that of the hardware. Unlike California, a modification is provided for in reserves valuation since in Texas the hardware tax is separately stated. Beginning in 1992 and thereafter, the reserves tax is inapplicable, as the hardware valuation exceeds that of the reserves.

COMPARATIVE STATE TAX BURDEN STUDY

EXHIBIT XV
INFLATED

CALCULATION OF SEVERANCE TAX

(In Thousands)

	Percentage Ownership in Prudhoe Pool	Alaska***	California	Kansas	Louisiana	New Mexico	Oklahoma	Texas	Wyoming
Percentage production-									
Estimated total production (in barrels)		7,657,000	N/A	N/A	8,688,000	8,688,000	8,688,000	8,688,000	8,688,000
Less- Royalty (in barrels)		957,125	N/A	N/A	1,086,000	1,086,000	1,086,000	1,086,000	1,086,000
Net taxable production (in barrels)		6,699,875	N/A	N/A	7,602,000	7,602,000	7,602,000	7,602,000	7,602,000
Wellhead price per barrel		*	N/A	N/A	**	*	*	*	*
Net taxable production		\$60,202,652	\$ N/A	\$ N/A	\$65,335,375	\$67,539,955	\$65,639,455	\$67,920,056	\$68,148,115
Tax rate		x .1225	N/A	N/A	x .125	x .0424	x .07	x .046	x .04
Total percentage production (A)		\$ 7,374,825	\$ NONE	\$ NONE	\$ 8,166,922	\$ 2,863,694	\$ 4,594,762	\$ 3,124,323	\$ 2,725,925
Cents per barrel-									
Estimated total production (in barrels)		1,031,000	N/A	N/A	N/A	8,688,000	N/A	N/A	N/A
Less- Royalty (in barrels)		128,875	N/A	N/A	N/A	1,086,000	N/A	N/A	N/A
Net taxable production (in barrels)		902,125	N/A	N/A	N/A	7,602,000	N/A	N/A	N/A
Tax rate per barrel		x .80	N/A	N/A	N/A	****	N/A	N/A	N/A
Total cents per barrel (B)		\$ 721,700	\$ NONE	\$ NONE	\$ N/A	\$ 4,402,000	\$ N/A	\$ N/A	\$ N/A
Total tax (Total of A and B)		\$ 8,096,525	\$ NONE	\$ NONE	\$ 8,166,922	\$ 7,265,694	\$ 4,594,762	\$ 3,124,323	\$ 2,725,925
Economic limit factor (Alaska)		x .826088	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tax for 100% ownership--25 years		\$ 6,688,442	\$ NONE	\$ NONE	\$ 8,166,922	\$ 7,265,694	\$ 4,594,762	\$ 3,124,323	\$ 2,725,925
Atlantic Richfield Company	20.2745	\$ 1,356,048	\$ N/A	\$ N/A	\$ 1,655,833	\$ 1,473,083	\$ 931,565	\$ 633,441	\$ 552,668
Exxon Corporation	20.2745	1,356,048	N/A	N/A	1,655,803	1,473,083	931,565	633,441	552,668
SONIO Petroleum Company	53.1552	3,555,255	N/A	N/A	4,341,144	3,862,094	2,442,355	1,660,740	1,448,971
		\$ 6,267,351	\$ NONE	\$ NONE	\$ 7,652,770	\$ 6,808,260	\$ 4,305,485	\$ 2,927,622	\$ 2,544,307

* See Exhibit XI.

** The wellhead price as computed on Exhibit XI is reduced by a 25 cents per barrel allowance for oil gathering facilities.

*** For years 1977 to 1979, cents per barrel tax exceeds percentage production tax. However, for years 1980 to 2001, the average wellhead price per barrel yields a percentage production tax rate which exceeds the .80 per barrel tax rate under the cents per barrel method.

**** The tax rate is \$.45 per barrel for 1977 and \$.479 per barrel for 1978. The tax rate for years 1979 to 1982 is inflated at the same rate as the market price of oil per Pritchard & Abbott Engineering Survey of Prudhoe Bay Sudlerochit Pool Unit Area, Table 7. The rate remains constant from 1982 to 2001.

COMPARATIVE STATE TAX BURDEN STUDYINCOME TAX SUMMARY

(In Thousands)

	Atlantic Richfield Company and/or Exhibit Subsidiaries	British Petroleum Company Limited and/or Subsidiaries	Exxon Corporation and/or Subsidiaries	The Standard Oil Company of Ohio and/or Subsidiaries	Total
Alaska--separate accounting for Prudhoe Bay Field, TAPS, and worldwide basis for other income	XVI(a) \$1,052,081	\$361,643	\$1,053,682	\$2,121,604	\$4,589,010
California--worldwide basis	XVI(b) 224,257	814,972	518,638	355,665	1,913,530
Kansas--consolidated return basis	XVI(c) 156,415	250,063	106,700	526,639	1,040,817
Louisiana--separate accounting for Prudhoe Bay Field and separate entity for TAPS	XVI(d) 276,718	156,186	290,891	702,046	1,425,841
New Mexico--separate entity	XVI(e) 229,563	182,129	287,393	741,994	1,441,079
Oklahoma--separate accounting for Prudhoe Bay Field and separate entity for TAPS	XVI(f) 268,677	138,674	292,536	694,559	1,394,446

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF ALASKA TAXABLE INCOME
FOR THE PERIOD 1978-2001
(In Thousands)

EXHIBIT XVII(a)
INFLATED

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field-					
Gross value at point of production	\$71,923,260				
Operating expenses-					
Royalty	\$ 8,245,648				
Operation--basic facility	5,811,000				
Other operating expenses	6,186,000				
Intangible drilling costs	1,619,520				
Depreciation	10,594,000				
Taxes-					
Ad valorem	2,567,130				
Severance	6,579,942				
General overhead	1,023,960				
Total operating expenses	\$42,628,190				
Net income before interest -	\$11,300,070	\$ 6,345,933*	\$ NONE	\$ 6,345,933*	\$16,637,615*
Less- Interest		512,455		212,216	2,155,064
Net income from Prudhoe Bay (A)		\$ 5,833,478	\$ NONE	\$ 6,133,717	\$14,482,551
TAPS (pipeline)-					
Tariff revenue	\$55,037,850				
Operating expenses-					
Operation	\$ 8,930,524				
Removal costs	1,500,377				
Depreciation	9,642,064				
Interest	8,274,240				
Ad valorem taxes	2,392,375				
Total operating expenses	\$30,740,580				
Net income from TAPS (B)	\$24,298,270	\$ 5,100,137*	\$ 3,847,262*	\$ 4,857,654*	\$ 8,097,709*
Net income from Prudhoe Bay Field and TAPS (A+B)		\$10,933,615	\$ 3,847,262	\$ 10,991,371	\$22,580,260
1976 worldwide net income before taxes x 24 years		\$25,833,575	\$72,768,000	\$187,944,000	\$ 4,628,568
Apportionment factor***					
Apportioned worldwide net income		\$ 258,436	\$ NONE	\$ 218,015	\$ NONE
Alaska taxable income--1978-2001		\$11,192,251	\$ 3,847,262	\$ 11,209,386	\$22,580,260
Alaska tax rate		x .094	x .094	x .094	x .094
Alaska income tax		\$ 1,052,021	\$ 361,643	\$ 1,053,682	\$ 2,121,984

* Apportioned according to ownership percentage.
** Proprietary information.
*** Apportionment factor for British Petroleum Company Limited and The Standard Oil Company is based on combined group information.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF CALIFORNIA TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

EXHIBIT XVIII
INFLATE

EXHIBIT A-85

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field-					
Gross revenues	\$150,167,720				
Less- Royalty	8,456,181				
Net revenue	\$141,711,539				
Operating expenses-					
Operation	\$ 12,139,000				
Intangible drilling costs	1,687,000				
Depreciation	10,652,000				
Taxes-					
Ad valorem	2,582,838				
Severance	-				
Transportation	19,287,360				
TAPS tariff	55,168,800				
Total operating expenses	\$101,516,998				
Net income before interest	\$ 40,194,541	\$ 8,149,242*	\$ N/A	\$ 8,149,242*	\$21,365,484*
Less- Interest		578,790	N/A	-	978,000
Net income from Prudhoe Bay (A)		\$ 7,570,452	\$ NONE	\$ 8,149,242	\$20,387,484
TAPS (pipeline)-					
Tariff revenue	\$ 55,168,800				
Operating expenses-					
Operation	\$ 9,041,810				
Removal costs	1,542,337				
Depreciation	10,014,650				
Interest	8,619,000				
Ad valorem taxes	1,803,200				
Total operating expenses	\$ 31,020,997				
Net income from TAPS (B)	\$ 24,147,803	\$ 5,071,049*	\$ 3,825,012*	\$ 4,829,561*	\$ 1,010,678*
Net income from Prudhoe Bay Field and TAPS (A + B)		\$12,641,491	\$ 3,825,012	\$ 12,978,803	\$21,408,162
1976 worldwide net income before taxes x 25 years		26,909,975	75,800,000	195,775,000	5,821,421
Total		\$19,551,466	\$79,625,012	\$108,753,803	\$27,229,583
Apportionment factor***					
California taxable income	\$ 2,491,742	\$ 9,055,219	\$ 5,752,649	\$ 1,911,313	\$ 1,911,313
California tax rate	x .09	x .09	x .09	x .09	x .09
California income tax	\$ 223,257	\$ 814,972	\$ 518,033	\$ 172,018	\$ 172,018

- * Apportioned according to ownership percentage.
- ** Proprietary Information.
- *** Apportionment factors for British Petroleum Company Limited and The Standard Oil Company are based on separate entity information for 1977 and combined group information for 1978 to 2001.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF KANSAS TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

	Total	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	The Standard Oil Company
Prudhoe Bay Field-					
Gross revenues	\$150,167,720				
Less- Royalty	8,336,721				
Net revenue	\$141,830,999				
Operating expenses-					
Operation--expenses	\$ 12,119,000				
Intangible drilling costs	1,687,000				
Depreciation	10,652,000				
Taxes-					
Ad valorem	5,794,525				
Severance	-				
Transportation	19,287,360				
TAPS tariff	56,124,480				
Total operating expenses	\$105,684,365				
Net income before interest and franchise tax	\$ 36,146,634	\$ 7,328,549*	\$ N/A	\$ 7,328,549*	\$19,213,816*
Less-					
Interest		578,790	N/A	-	978,000
Franchise tax		63	N/A	63	63
Net income from Prudhoe Bay (A)		\$ 6,749,696	\$ N/A	\$ 7,328,486	\$18,235,755
TAPS (pipeline)-					
Tariff revenue	\$ 56,124,480				
Operating expenses-					
Operation	\$ 9,041,810				
Removal costs	1,542,337				
Depreciation	10,014,650				
Interest	8,619,000				
Ad valorem taxes	3,234,350				
Total operating expenses	\$ 32,452,147				
Net income before franchise tax	\$ 23,672,333	\$ 4,971,191*	\$3,749,698*	\$ 4,734,467*	\$ 7,892,356*
Less- Franchise tax		63	63	63	63
Net income from TAPS (B)		\$ 4,971,127	\$3,749,635	\$ 4,734,404	\$ 7,892,293
Net income from Prudhoe Bay Field and TAPS (A + B)		\$11,720,823	\$3,749,635	\$12,062,890	\$26,128,046
1976 U.S. consolidated net income x 25 years		25,061,050	-	45,200,000	2,800,000
Total		\$36,781,873	\$3,749,635	\$57,262,890	\$28,928,046
Apportionment factor		**	**	**	**
Total Kansas taxable income		\$ 2,317,258	\$3,704,639	\$ 1,580,742	\$ 7,910,292
Kansas tax rate		x .0075	x .0075	x .0075	x .0075
Kansas income tax		\$ 156,415	\$ 250,063	\$ 106,703	\$ 536,610

* Apportioned according to ownership percentage.

** Proprietary information.

COMPARATIVE STATE OF MISSISSIPPI
CALCULATION OF LOUISIANA TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

EXHIBIT 2010
10/1/10

EXHIBIT A-87

	Atlantic Held Ltd Company/ Sutro	Pipe Line Company	Pipelines, Inc.	Enron Corporation/ Enron Pipe Line Company	South Piedmont Company/ SOUTH Pipe Line Company
Prudhoe Bay Field-					
Gross Revenue	\$150,167,720				
Less: Royalty	\$ 597,641				
Net Revenue	\$151,570,359				
Operating expenses-					
Operation	\$ 12,119,000				
Intangible drilling costs	1,687,000				
Depreciation	10,652,000				
Taxes-					
Ad valorem	1,177,675				
Severance	8,115,922				
Transportation	19,287,360				
FIPS tariff	44,039,360				
General overhead	1,042,560				
Total operating expenses	\$108,151,377				
Net income before interest and franchise tax	\$ 33,378,682	\$0,767,320	\$ N/A	\$6,767,320	\$17,742,390
Less-					
Interest	578,750	N/A			974,000
Franchise tax	8,450	N/A		9,875	21,550
Federal taxable income	\$7,180,080	\$ N/A		\$6,757,445	\$16,742,449
Less-					
Federal income tax	1,665,668	N/A		1,598,914	3,968,931
Depreciation	2,992,130	N/A		3,281,501	8,114,360
Louisiana taxable income--Prudhoe Bay (A)	\$1,721,506	\$ NONE		\$1,177,010	\$4,659,158
TAPS (Pipeline)-					
Tariff revenue	\$ 54,014,360				
Operating expenses-					
Operation	\$ 5,011,810				
Removal costs	1,542,317				
Depreciation	10,014,000				
Interest	8,619,000				
Ad valorem taxes	1,441,925				
Total operating expenses	\$ 26,641,782				
Net income before franchise tax	\$ 23,049,938	\$1,208,878	\$3,705,711	\$4,678,920	\$ 7,796,772
Less- Franchise tax					
Net income from TAPS	10,200	40,175		50,350	37,000
1976 pipeline (20-year entity) net income before taxes x 25 years	1,762,749	\$1,659,336		\$1,628,678	\$ 7,704,112
Total	\$5,081	\$1,699,336	\$1,303,132	\$1,327,810	\$ 7,779,019
Apportionment factor					
Income subject to Federal income tax	\$1,217,317	\$1,615,424		\$1,557,633	\$ 7,623,433
Less- Federal income tax	1,580,967	1,663,095		1,598,511	3,530,732
Louisiana taxable income--TAPS (B)	\$1,737,070	\$1,952,329		\$1,759,122	\$ 4,110,697
Louisiana taxable income (A + B)	\$1,737,070	\$1,952,329		\$1,759,122	\$ 4,110,697
Louisiana tax rate	1.24%	1.24%	1.24%	1.24%	1.24%
Total income tax	\$ 216,718	\$ 156,186		\$ 220,831	\$ 762,076

* Apportionment factor is based on the following percentages:

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF NEW MEXICO TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

	Total	Atlantic Richfield Company/ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SONIO Petroleum Company/ SONIO Pipe Line Company
Prudhoe Bay Field-					
Gross revenues	\$150,147,720				
Less- Royalty	8,640,801				
Net revenue	\$141,506,919				
Operating expenses-					
Operation	\$ 12,143,000				
Intangible drilling costs	1,687,000				
Depreciation	10,662,000				
Taxes-					
Ad valorem	211,550				
Severance	7,265,692				
Transportation	19,287,360				
TAPS tariff	53,691,840				
Total operating expenses	\$104,936,444				
Net income before interest and franchise tax	\$ 36,570,475	\$ 7,418,536*	\$ N/A	\$ 7,418,536*	\$19,449,540*
Less-					
Interest		578,790	N/A		578,000
Franchise tax		6,011	N/A	7,437	5,482
Net income from Prudhoe Bay		\$ 6,833,735	\$ N/A	\$ 7,410,699	\$18,466,238
1976 net income before taxes of separate entity holding title to Prudhoe Bay a 25 years		14,724,550	N/A	73,364,000	1,560,425
Total		\$21,558,285	\$ N/A	\$80,774,699	\$20,026,663
Apportionment factor			N/A		
New Mexico taxable income--Prudhoe Bay (A)		\$ 1,358,172	\$ None	\$ 2,475,219	\$ 7,157,295
TAPS (pipeline)-					
Tariff revenue	\$ 53,691,840				
Operating expenses-					
Operation	\$ 9,041,810				
Removal costs	1,547,137				
Depreciation	19,014,000				
Interest	8,619,000				
Ad valorem taxes	1,177,490				
Total operating expenses	\$ 40,399,247				
Net income before franchise taxes	\$ 21,290,593	\$ 4,892,285*	\$3,690,180*	\$ 4,619,319*	\$ 7,767,034*
Less- Franchise tax		2,928	3,360	2,889	2,568
Net income from TAPS		\$ 4,889,327	\$3,686,820	\$ 4,616,430	\$ 7,764,466
1976 pipeline (separate entity) net income before taxes x 25 years		656,283	-	1,399,132	74,947
Total		\$ 5,545,610	\$3,686,820	\$ 6,015,562	\$ 7,839,413
Apportionment factor					
New Mexico taxable income--TAPS (B)		\$ 3,233,091	\$3,642,578	\$ 3,272,032	\$ 7,682,576
Total New Mexico taxable income (A + B)		\$ 4,591,263	\$3,642,578	\$ 5,747,451	\$14,839,872
New Mexico tax rate		x .05	x .05	x .05	x .05
New Mexico income tax		\$ 229,563	\$ 182,129	\$ 287,393	\$ 741,996

* Apportioned according to ownership percentage.

** Proprietary information.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF OKLAHOMA TAXABLE INCOME
FOR THE PERIOD 1977 - 2001
(In Thousands)

EXHIBIT XV(f)
INFLATED

EXHIBIT
A-89

	Total	Atlantic Richfield Company/ ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/ SOHIO Pipe Line Company
Prudhoe Bay Field-					
Gross revenues	\$150,167,720				
Less- Royalty	8,169,301				
Net revenue	\$141,798,419				
Operating expenses-					
Operation	\$ 12,139,000				
Intangible drilling costs	1,687,000				
Depreciation	10,652,000				
Taxes-					
Ad valorem	545,725				
Severance	4,594,762				
Transportation	19,287,360				
TAPS tariff	55,863,340				
General overhead	1,042,560				
Total operating expenses	\$105,812,247				
Net income before interest, franchise tax, and depletion	\$ 35,986,172	\$7,296,016*	\$ N/A	\$7,296,016*	\$19,128,122*
Less-					
Interest		578,790	N/A	-	978,000
Franchise tax		500	N/A	500	500
Depletion		2,927,776	N/A	2,927,776	7,635,972
Oklahoma taxable income--Prudhoe Bay (A)	\$3,738,950	\$ N/A	\$ NONE	\$4,367,740	\$10,474,050
TAPS (pipeline)-					
Tariff revenue	\$ 55,863,840				
Operating expenses-					
Operation	\$ 9,041,810				
Removal costs	1,542,337				
Depreciation	10,014,650				
Interest	8,619,000				
Ad valorem taxes	3,567,300				
Total operating expenses	\$ 32,785,097				
Net income before franchise tax	\$ 23,078,743	\$4,846,536*	\$3,655,673*	\$4,615,740*	\$ 7,694,153*
Less- Franchise tax		500	500	500	500
Net income from TAPS	\$2,876,036	\$3,655,173	\$4,615,249	\$ 7,693,951	
1976 pipeline (separate entity) net income before taxes x 25 years	656,233	-	1,399,122	74,647	
Total	\$2,502,110	\$3,655,173	\$6,014,371	\$ 7,768,598	
Apportionment factor					
Oklahoma taxable income--TAPS (B)	\$1,307,852	\$1,611,311	\$3,250,376	\$ 7,613,474	
Total Oklahoma taxable income (A + B)	\$5,046,802	\$5,307,482	\$7,864,747	\$18,088,024	
Oklahoma tax rate	x .0284	x .0284	x .0384	x .0384	
Oklahoma income tax	\$ 1,433,291	\$ 1,507,325	\$ 3,000,386	\$ 6,947,691	

* Apportionment according to ownership percentage.
** Projected Tax for 1977-2001

COMPARATIVE STATE TAX BURDEN STUDY

FRANCHISE TAX SUMMARY

(In Thousands)

	Exhibit	Atlantic Richfield Company/ ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Corporation/ Exxon Pipe Line Company	SOHIO Petroleum Company/ SOHIO Pipe Line Company	Total
Kansas*- Prudhoe Bay Pipeline		\$ 63 63	\$ N/A 63	\$ 63 63	\$ 63 63	\$ 189 252
Total		\$ 126 =====	\$ 63 =====	\$ 126 =====	\$ 126 =====	\$ 441 =====
Louisiana- Prudhoe Bay Pipeline	XVII(a)	\$ 8,450	\$ N/A	\$ 9,875	\$ 21,950	\$ 40,275
	XVII(a)	50,225	46,375	50,250	95,600	242,450
Total		\$ 58,675 =====	\$ 46,375 =====	\$ 60,125 =====	\$117,550 =====	\$ 282,725 =====
New Mexico- Prudhoe Bay Pipeline	XVII(b)	\$ 6,011	\$ N/A	\$ 7,837	\$ 5,482	\$ 19,330
	XVII(b)	2,958	3,360	2,889	2,568	11,775
Total		\$ 8,969 =====	\$ 3,360 =====	\$ 10,726 =====	\$ 8,050 =====	\$ 31,105 =====
Oklahoma***- Prudhoe Bay Pipeline		\$ 500 500	\$ N/A 500	\$ 500 500	\$ 500 500	\$ 1,500 2,000
Total		\$ 1,000 =====	\$ 500 =====	\$ 1,000 =====	\$ 1,000 =====	\$ 3,500 =====
Texas- Prudhoe Bay Pipeline***	XVII(c)	\$ 75,375	\$ N/A	\$ 75,375	\$197,625	\$ 348,375
	XVII(c)	52,700	39,750	50,200	83,700	226,350
Total		\$128,075 =====	\$ 39,750 =====	\$125,575 =====	\$281,325 =====	\$ 574,725 =====
Wyoming- Prudhoe Bay Pipeline	XVII(e)	\$ 1,025	\$ N/A	\$ 1,025	\$ 2,650	\$ 4,700
	XVII(e)	250	200	250	400	1,100
Total		\$ 1,275 =====	\$ 200 =====	\$ 1,275 =====	\$ 3,050 =====	\$ 5,800 =====

* Assumed maximum tax of \$2,500 per year for each company.

** Assumed maximum tax of \$20,000 per year for each company.

*** Includes intangibles tax on pipeline.

EXHIBIT XVII(a)
INFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF LOUISIANA FRANCHISE TAX
(In Thousands)

	Prudhoe Bay			TAPS				
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Apportioned equity and borrowed capital-								
Equity	\$	* \$ N/A	\$13,833,098	\$	* \$ 250,476	\$ 255,958	\$ 271,916	\$ 192,881
Borrowed capital		* N/A	3,214,078		* 1,287,766	986,576	1,356,374	2,468,112
Total	\$	\$ None	\$17,047,176	\$	\$1,538,242	\$1,242,534	\$1,628,290	\$2,660,993
Apportionment factor		* N/A	*		*	*	*	*
Apportioned capital (A)	\$225,356	\$ None	\$ 263,277	\$585,144	\$1,339,117	\$1,236,756	\$1,340,293	\$2,549,619
Assessed valuation--total assessed property located in state (B)	\$159,178	\$ N/A	\$ 159,178	\$417,328	\$ 199,769	\$ 150,683	\$ 190,256	\$ 317,157
Greater of (A) or (B)	\$225,356	\$ None	\$ 263,277	\$585,144	\$1,339,117	\$1,236,756	\$1,340,293	\$2,549,619
Tax rate	x .0015	N/A	x .0015	x .0015	x .0015	x .0015	x .0015	x .0015
Franchise tax--1 year	\$ 338	\$ None	\$ 395	\$ 878	\$ 2,009	\$ 1,855	\$ 2,010	\$ 3,824
Franchise tax--25 years	\$ 8,450	\$ None	\$ 9,875	\$ 21,950	\$ 50,225	\$ 46,375	\$ 50,250	\$ 95,600

* Proprietary information.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF NEW MEXICO FRANCHISE TAX
(In Thousands)

	Prudhoe Bay			TAPS				
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Equity**	\$ *	\$ N/A	\$ *	\$ *	\$ *	\$ *	\$ *	\$ *
Apportionment factor	*	N/A	*	*	*	*	*	*
Apportioned equity	\$453,625	\$ NONE	\$589,063	\$410,490	\$221,783	\$255,115	\$217,959	\$194,531
Tax rate	x .00055	N/A	x .00055	x .00055	x .00055	x .00055	x .00055	x .00055
Franchise tax--Each year after 1977	\$ 249	\$ NONE	\$ 324	\$ 226	\$ 122	\$ 140	\$ 120	\$ 107
Franchise tax--1978-2001	\$ 5,976	\$ NONE	\$ 7,776	\$ 5,424	\$ 2,928	\$ 3,360	\$ 2,880	\$ 2,568
Franchise tax--1977	\$ 35	\$ NONE	\$ 61	\$ 58	\$ 30	\$ -	\$ 9	\$ -
Franchise tax--25 years	\$ 6,011	\$ NONE	\$ 7,837	\$ 5,482	\$ 2,958	\$ 3,360	\$ 2,889	\$ 2,568

* Proprietary information.

** Franchise tax base is capital stock for 1977 and equity for 1978 to 2001.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF TEXAS FRANCHISE TAX
(In Thousands)

	Prudhoe Bay				TAPS			
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Apportioned equity and borrowed capital- Equity	\$ N/A	* \$ N/A	\$ N/A	* \$ N/A	* \$ N/A	* \$ N/A	* \$ N/A	* \$ N/A
Borrowed capital								
Total Apportionment factor	\$	* \$ NONE	\$	* \$	* \$	* \$	* \$	* \$
Apportioned capital (A)	\$ NONE	\$ NONE	\$ 20,965	\$ 96,622	\$ 219,682	\$ 261,973	\$ 218,616	\$ 201,613
Assessed valuation--total county assessed property located in state (B)	\$ 709,454	\$ N/A	\$ 709,454	\$ 1,860,031	\$ 351,120	\$ 264,845	\$ 334,400	\$ 557,445
Greater of (A) or (B)	\$ 709,454	\$ NONE	\$ 709,454	\$ 1,860,031	\$ 351,120	\$ 264,845	\$ 334,400	\$ 557,445
Tax rate	x .00425	N/A	x .00425	x .00425	x .00425	x .00425	x .00425	x .00425
Franchise tax before reductions	\$ 3,015	\$ NONE	\$ 3,015	\$ 7,905	\$ 1,492	\$ 1,126	\$ 1,421	\$ 2,369
80% reduction of franchise tax due to taxation of intangibles (Texas)	N/A	N/A	N/A	N/A	(1,194)	(901)	(1,137)	(1,895)
Total franchise tax liability	\$ 3,015	\$ NONE	\$ 3,015	\$ 7,905	\$ 298	\$ 225	\$ 284	\$ 474
Intangibles tax on pipeline (Exhibit XVII(d))	N/A	N/A	N/A	N/A	1,810	1,365	1,724	2,874
Total franchise and intangibles tax--1 year	\$ 3,015	\$ NONE	\$ 3,015	\$ 7,905	\$ 2,108	\$ 1,590	\$ 2,008	\$ 3,348
Total franchise and intangibles tax--25 years	\$ 75,375	\$ NONE	\$ 75,375	\$ 197,625	\$ 52,700	\$ 39,750	\$ 50,200	\$ 83,700

* Proprietary information.

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF TEXAS INTANGIBLES TAX ON PIPELINE

(In Thousands)

	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Net operating income*	\$ 99,670	\$ 75,180	\$ 94,924	\$ 158,238
Capitalization rate	+ .07	+ .07	+ .07	+ .07
Valuation	\$1,423,857	\$1,074,000	\$1,356,057	\$ 2,260,543
Less: Average depreciated book value	844,621	637,085	804,401	1,340,936
Total value subject to assessment	\$ 579,236	\$ 436,915	\$ 551,656	\$ 919,607
Average assessment rate	x .25	x .25	x .25	x .25
Taxable value	\$ 144,809	\$ 109,229	\$ 137,914	\$ 229,902
Tax rate	x .0125	x .0125	x .0125	x .0125
Intangibles tax--1 year	\$ 1,810	\$ 1,365	\$ 1,724	\$ 2,874
Intangibles tax--25 years	\$ 45,250	\$ 34,125	\$ 43,100	\$ 71,850

* Twenty-five year average return on investment from
TAPS tariff computation apportioned according to
ownership percentages.

EXHIBIT XVII(c)
INFLATED

COMPARATIVE STATE TAX BURDEN STUDY
CALCULATION OF WYOMING FRANCHISE TAX

(In Thousands)

	Prudhoe Bay				TAPS			
	Atlantic Richfield Company	British Petroleum Company Limited	Exxon Corporation	SOHIO Petroleum Company	ARCO Pipe Line Company	BP Pipelines, Inc.	Exxon Pipe Line Company	SOHIO Pipe Line Company
Assessed valuation-								
Total assessed property located in state	\$812,051	\$ N/A	\$812,051	\$2,129,016	\$201,600	\$152,064	\$192,000	\$320,064
Tax rate	x .00005	N/A	x .00005	x .00005	x .00005	x .00005	x .00005	x .00005
Total franchise tax liability--1 year	\$ 41	\$ NONE	\$ 41	\$ 106	\$ 10	\$ 8	\$ 10	\$ 16
Total franchise tax liability--25 years	\$ 1,025	\$ NONE	\$ 1,025	\$ 2,650	\$ 250	\$ 200	\$ 250	\$ 400

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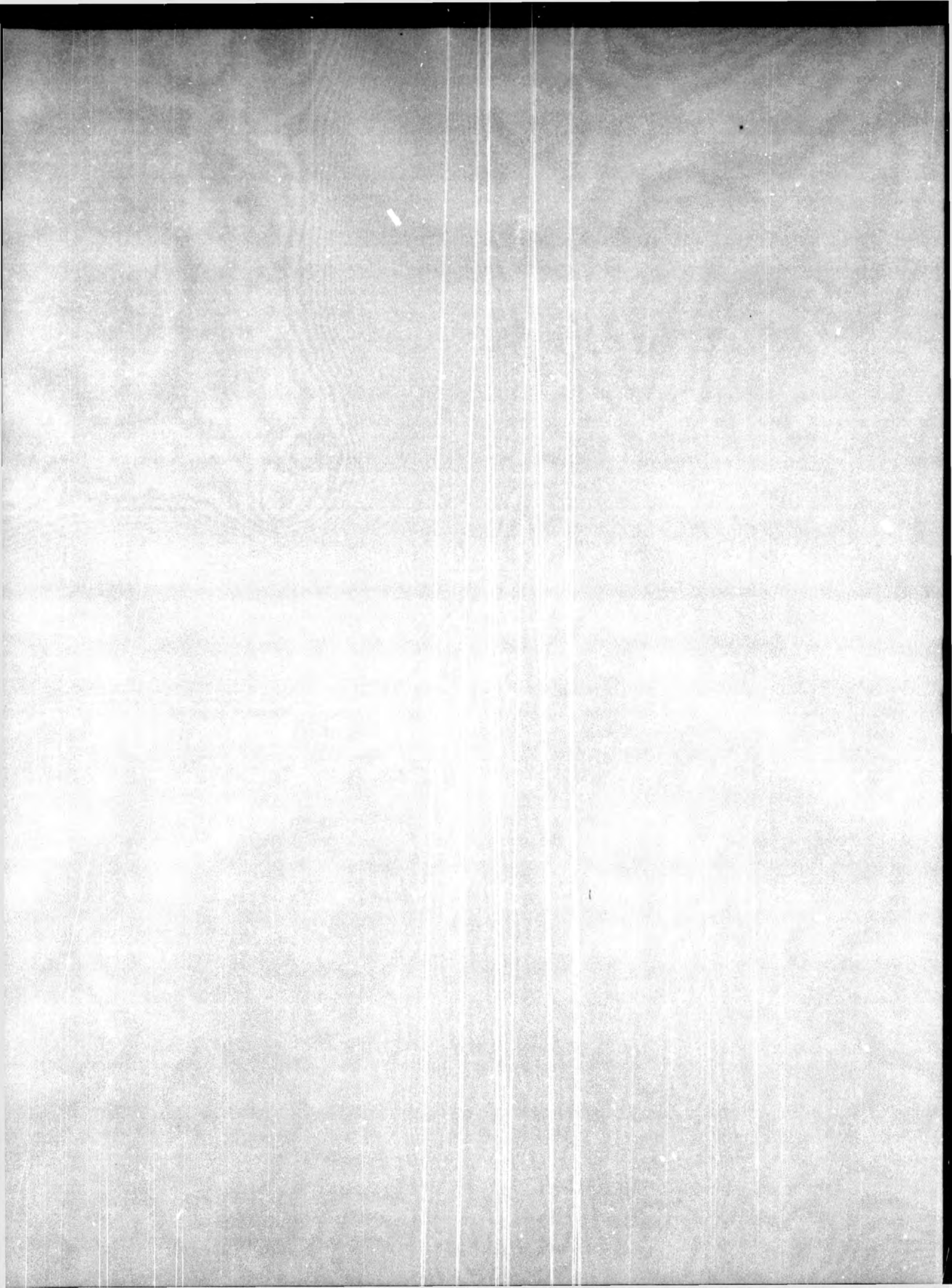
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ALASKA OIL AND GAS INCOME TAXATION
A Review of the State's Current Options

prepared for

The Alaska State Legislature
Joint Gas Pipeline Committee

By

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April 15, 1981

CONTENTS

	<u>Page</u>
FORWARD	ii
PART I -- OVERVIEW	i
PART II -- BACKSTOP CRITERIA	7
PART III -- TAX TYPES	12
PART IV -- BACKSTOP MECHANISMS	20
PART V -- CONCLUSIONS AND RECOMMENDATIONS	28
APPENDIX A -- JOINT STATEMENT ON OIL TAXES	31
APPENDIX B -- A NOTE ON RESERVOIR VALUATION METHODOLOGY	33
APPENDIX C -- A NOTE ON DATA SOURCES	37
THE AUTHORS	37

LIST OF TABLES

	<u>Page</u>
TABLE I -- Estimated Chapter 21 Collections By Fiscal Years	1
TABLE II -- Oil Production Tax Estimates At Current Tax Rates	13
TABLE III -- Analysis of Oil Production Tax Rates . .	14
TABLE IV -- Needed Increases In Oil Production Tax Rate To Offset Chapter 21 Revenues By Years	14
TABLE V -- Reserves Tax Rates Required To Raise Chapter 21 Revenues	17
TABLE VI -- Prudhoe Bay Preliminary Field Valuation Results	18
TABLE VII -- Revenue Estimates For Recommended Options	30

FOREWARD

This study was prepared under a contract with the Legislative Affairs Agency of the Alaska State Legislature.

The agreement directed us to

. . . review and report on the options available for implementing the goals established in the Joint Statement on Oil Taxes issued by the Governor, the President of the Senate, the Speaker of the House, the Finance Chairmen of their respective houses and other legislative leaders on March 18, 1981.

It was specified that our report should include

legal, economic and fiscal analysis of the various options identified . . . to enable an informed choice of options for further consideration. . . [and our] recommendations as to the identified options.

Although the time allowed to fulfill this assignment was extremely limited (13 days), we have prepared a reasonably comprehensive survey of the State's options. However, the analysis here is not sufficiently detailed to support any final decision on the form of a new oil tax structure, be it temporary or permanent. We do see this document, and the work by others now underway, as useful and perhaps crucial to narrowing the focus of efforts in the immediate future if it is decided to proceed.

The report which follows is the joint product of the three authors. The supporting revenue and economic studies were the responsibility of Mr. Eppenbach and Mr. Erickson. The necessary legal analysis was carried out by Mr. Messenger, who also served as project manager.

We wish to thank the many individuals who, often on very short notice, generously made themselves available to

answer our questions and who provided us with much useful data. Personnel of the Department of Revenue must lead this list--Commissioner Thomas Williams, Deputy Commissioner Joseph Donohue, Director of Petroleum Revenue Robert Johnson, Jerry Heier, Lou Nelson, and especially Charles Logsdon. Mark Wittow and Kevin McCarthy of the legislative staff also provided important information, as did Milt Barker of the Legislative Finance Division. The use of data processing facilities at the House Research Agency was crucial to producing this study within the specified time.

I

OVERVIEW

A major part of the revenues expected to accrue from Alaska's oil and gas resources have been put at risk by a lawsuit challenging A.S. 43.21, the State's oil and gas corporate income tax (hereinafter "Ch. 21"). If the litigation is finally resolved in late 1985, the State could--in the worst case--be required to return up to \$9 billion to the corporate taxpayers (see Table I).

TABLE I

ESTIMATED CH. 21 (PETROLEUM INCOME TAX)
COLLECTIONS BY FISCAL YEARS
(Millions of Dollars)

<u>Fiscal Year</u>	<u>Annual Collections</u>
1979	233 (actual)
1980	548 (actual)
1981	808
1982	1303
1983	1541
1984	1783
1985	<u>2141</u>
Total for period	8357

In a March 18, 1981 Joint Statement, the legislative leadership and the administration (see Appendix A) announced Alaska's position with respect to this risk: The current share of oil revenues between the producers, the federal government, and the State is fair; it should be preserved in

the future as a model of stability and restraint for other petroleum producing jurisdictions. These goals--and Alaska's established revenue share--will be seriously compromised if the plaintiffs win.

Although legal opinions differ on the State's chances of prevailing in the current lawsuit, no one has suggested that it is free from risk. The large sums involved make even a small victory by the litigants (or a small probability of a big victory) a matter of serious concern.

If the litigation result is a relatively small loss (say \$1 billion in 1985), it could be recouped over a few years with increased petroleum taxes. A loss of any larger magnitude would place the State in financial extremis. One option to deal with this problem is to await the outcome of the lawsuit before taking action. There are, however, real economic, legal and political restraints on recouping a substantial portion of lost Ch. 21 revenues under this option.

One way of implementing this option would be to attempt to collect the lost revenues prospectively. The State's oil and gas resources and the oil and gas tax base whether measured by gross production revenues, income streams, or reserves valuation, is depleting. The ability to offset this depletion by raising the tax rates has economic limits. This is especially true if one is attempting to cover lost revenues and also provide for the then current needs. In addition, there are real--albeit poorly defined--political and constitutional limits to the tax rates that would be

required to cover both past lost revenues and future needs. The legal challenge of Montana's 30 percent severance tax (now before the U.S. Supreme Court) and congressional proposals to limit state severance and income taxes are some examples.

Alternatively, in the event of an unfavorable decision, the State could attempt to make up the loss by making tax changes retroactively to 1978. A serious constitutional question would be raised by such a retroactive imposition. States have some latitude in imposing taxes retroactively, but not without limit. Taxes made retroactive to the beginning of a current tax year or applied to recent transactions have been upheld. Similarly, curative statutes which cure invalid tax proceedings or administrative action retroactively have been sanctioned. On the other hand, some other retroactive impositions such as gift and death tax changes have been struck down on the ground that the nature or amount of the tax could not reasonably have been anticipated at the time of the transaction which was later made taxable. Although not entirely clear, tax changes in 1985 of the magnitude needed to cover a loss of Ch. 21 revenues and the period of retroactivity (seven years to 1978) would at least carry a serious legal risk.

Since waiting out the law suit would still leave State revenues at risk, we believe that a decision to do nothing other than litigate the suit will not constitute, in the language of the Joint Statement, "a sound strategy for

protecting oil and gas revenues."

This does not mean that an aggressive effort to win the current litigation is unimportant. Indeed, we consider it an essential part of any plan for protecting the State's revenues. Even if the current oil and gas corporate tax, A.S. 43.21 were repealed this session and replaced by some other tax that raised as much revenue, the result would be to leave in excess of \$1 billion already collected by the State at risk.

This billion dollar "overhang" has important implications for the State's efforts to achieve the objectives outlined in the joint statement. Because of the overhang, any new tax designed to replace Ch. 21, or any attempt to create a "saftey net" tax to backstop Ch. 21 (which was enacted in 1978), must either be retroactive to 1978, or otherwise protect more money than the oil and gas corporate tax will collect in future. As we shall show later, this constraint limits the options available to the legislature.

Whether to replace Ch. 21 with a new permanent tax, or to simply protect its revenues with a backstop of some sort is a decision that turns on the degree and range of certainty required with respect to policy, fiscal and legal issues.

On the one hand, to fashion a workable backstop the legislature need mainly be concerned with fiscal effects as they unfold over a limited time span, between now and whenever the litigation is finally resolved, say 1985. Further, the basic criteria that a backstop must satisfy are rela-

tively simple. First, it must have sufficient fiscal horsepower to cover the exposed Ch. 21 revenues. Second, it must be legally (and politically, with respect to the federal government) secure.

Before adopting a permanent substitute for Ch. 21, we expect that the legislature will wish to give it a far more searching examination than would be necessary under the backstop approach. For example, the fiscal effects of a new permanent tax should be examined under a larger set of possible circumstances, and over a longer time frame. Its effects on future exploration and development, for example, would need to be forecast under a similarly wide range of alternative assumptions, as would its effects on differently situated oil and gas producers, and pipeline operators. Most of all, the legal and fiscal security of a replacement must be close to absolute, since a new tax is not the second and reinforcing line of defense that would be created by a backstop; it is a new first line of defense which must stand alone.

In all candor, we doubt that these conditions can be met in the time remaining in this session. Our experience with this type of legislation, going back to 1972, leads us to believe that consensus on the issues raised by a whole new permanent petroleum income tax will require substantial work to achieve. This was certainly the case in 1978, when Ch. 21 was enacted. Numerous concepts for revising the tax were introduced by different legislators and the administra-

tion over the three years preceeding enactment of Ch. 21. Two interim committees approached the task and arrived at very different policy recommendations. After a general consensus had been reached, it took six weeks of very intensive effort to embody the concept in an act that everyone could be reasonably confident would do what was expected of it.

Much of the work done over the 1975-1978 period is and would be relevant to recasting the tax now; but even so, the policy differences are likely to remain. For example, some will claim that two corporations with exactly the same Alaska assets, activities and profits will be taxed differently, and therefore inequitably under any apportionment formula. Others will argue that apportionment is the most appropriate way to tax a unitary business. Similarly, resolving legal questions and revenue projections with reasonable degrees of certainty would surely require much further analysis. Resolving issues of this sort, if they are resolvable, will take time.

II

BACKSTOP CRITERIA

A backstop is much more likely to be achievable within the six weeks or so remaining in this session, but even so, developing a backstop tax will not be a simple task. To serve its purpose a backstop measure must (1) have sufficient fiscal horsepower to cover the revenues at risk, and (2) be legally and politically secure. Some tax bases are probably not large enough to achieve both of these objectives in an absolute sense. As a result, a marginal increment of revenue security would need to be given up to achieve the highest possible legal security (or vice versa). For example, as we note below, any apportionment formula that raises as much revenue as Ch. 21 will almost certainly be challenged and will carry some legal risk.

These matters, and the question of tradeoffs, are addressed below in the context of specific taxes. However, in order to assess these, it is necessary to discuss the other secondary goals which the legislature will probably consider relevant. These are, in no particular order, the following:

Minimize Adverse Effects on the Current Lawsuit. For example, a backstop tax which made use of the three factor apportionment formula which the oil company plaintiffs are arguing for in their suit could be construed as giving them at least moral support in their assertions, and raise questions about the State's own confidence in that part of its

case. The same could be said about any backstop tax, but a specific use of the plaintiffs' favored approach could be especially difficult to explain.

Administrative Convenience. In the context of the large sums we are discussing here the extra costs of administering even the most difficult tax are not very significant. Moreover, the assertions made to previous legislatures by the petroleum industry that the 1975 reserves tax and the 1978 corporate tax proposal would create an "administrative nightmare" and "a huge revenue bureaucracy" have not been validated by actual experience with those taxes.

On the other hand, the fact that some taxes are easier to administer than others is not irrelevant. For example, the very simple reserves tax requires, in the assessment process, substantial technical skill and high levels of administrative integrity. The fact that the Alaska Department of Revenue managed this tax quite well for the two years it was in effect probably does not entirely mitigate the importance of administrative convenience.

Simplicity. By this we mean that the tax should be known and understandable. Taxes which the legislature has already dealt with in the past are to be preferred, other things being equal, to those that are relatively untried or complex in their workings. The severance tax, the reserves tax and the existing apportioned income tax in Ch. 20 all score high in this regard.

Overcollecting. It is important that Alaska not reach

beyond its stated goal of protecting its current share of petroleum revenues. This does not mean that a backstop tax or mechanism need collect or cover collections of exactly the same revenues as will be raised by Ch. 21, which in any event are uncertain. It does mean, however, that the collections should be comparable.

Minimize the Likelihood of Adverse Federal Reaction.

Much has been said about the risks of congressional reaction to Alaska's attempts at securing what it considers its fair share of resource revenues. Consuming states have shown increased willingness to use political and judicial tools to limit that share to what they consider fair. The suit against Montana's 30 percent coal severance tax is an example.* Additionally, there have been several congressional proposals which would limit state severance and income taxes.** Although none of these proposals have become law, they can not be dismissed. Action which Alaska might take could have an effect on such proposals.

Symmetry. The taxpayers affected by a backstop, and the tax burdens it currently or prospectively creates should correspond as nearly as possible with Ch. 21, in order that the backstop not disturb the policy judgments already made by the legislature.

* Commonwealth Edison Co. v. State, 615, P.2d. 847 (Mont. 1980).

** Just some of these proposals include S.1778 96th Cong. 1st Sess. (1979); H.R. 1983 97th Cong. 1st Sess. (1981); S.655 97th Cong. 1st Sess. (1981); H.R. 5076 96th Cong. 1st Sess. (1979); S.1688 96th Cong. 1st Sess. (1979).

Obviously, perfect symmetry in this sense is not possible without knowing each taxpayer's particular tax position. Although it might be desirable from a policy standpoint, achieving that perfect symmetry would carry some additional legal risks. For example, suppose A.S. 43.21 were found invalid, but through the adoption of a backstop mechanism each taxpayer was still required to pay exactly the same amount. An argument could be made that the legislature was simply enforcing an otherwise invalid tax under the guise of a new tax.

Certainty of Revenue Effects. Those of us who have had responsibility for forecasting revenues have an acute sense of how important this criterion is. On one level, certainty of revenue effect means you are much less likely to find yourself mercilessly criticized for missing the mark on your revenue estimate. Beyond that, certainty of revenue effect means that State fiscal planning can be made with more confidence.

No tax can be forecast with complete certainty. Oil and gas taxes are difficult because they are extremely sensitive to world oil prices and to production. Some oil and gas taxes, however, are much more difficult than others. A flat cents-per-barrel tax is easy since there is only one variable to worry about. A corporate income tax using the apportionment formula is more difficult to forecast, since it depends on the entire world wide tax position of each taxpayer which may change from year to year.

Although legislators themselves are not likely to make the actual estimates, they have the same problem. A backstop tax which turns out to have protected less revenue than expected could be difficult to explain to those who, rightly, could care less about the technical problems of forecasting.

Minimize Spillover Effects. Spillovers include all the effects of a tax that were not intended. With respect to the taxes under consideration here, they can range from increased gas rates in Anchorage if a gas severance tax were part of a backstop mechanism, to effects on future exploration and development. Some spillovers may be positive: Some have suggested that earlier construction of the Northwest Gas Pipeline could conceivably result from including a gas reserves tax in a backstop arrangement.

A full analysis of just those spillovers that we consider likely would take as much space as this entire study. Fortunately, most of these will probably not be very significant because the backstop tax will be temporary and the backstop mechanism can mitigate spillover effects to some extent. Where spillover effects may have political or especially significant economic repercussions, they have been identified in the discussion of the individual tax or backstop mechanism that could cause them.

III

TAX TYPES

In our analysis of the backstop approach, we have found it useful, at least initially, to separate the consideration of taxes, per se, from the mechanisms by which they would be made to protect the State's Ch. 21 revenues. For example, enacting a new tax and escrowing Ch. 21 revenues is one mechanism. Allowing Ch. 21 payments to be credited against the new tax is another. Either mechanism could be applied to any of the possible backstop taxes considered here.

A large set of possible taxes was considered in this survey, but all can be adequately described under three basic headings categorized by whether the tax base is (1) the gross revenues from the production stream of oil and gas, (2) the profits derived from that stream, or (3) the value of the property (including reserves) that makes the production possible.

The greater part of our analysis has been devoted to determining with as much certainty as possible the amount of what we have called fiscal horsepower inherent in each of these tax bases, as well as the political and legal constraints on Alaska's ability to achieve that horsepower.

These tradeoffs, horsepower against security, are discussed below in the context of the three specific tax types.

Production or Severance Taxes have several important advantages. They are generally easy to assess, and are a traditional means of raising revenue from the petroleum

industry. Most importantly in this context, a production tax has an inherently large potential for fiscal horsepower, as shown in Table II:

TABLE II
OIL PRODUCTION TAX ESTIMATES
AT CURRENT TAX RATES
(Millions of Dollars)

<u>Fiscal Year</u>	<u>North Slope Production</u>	<u>Cook Inlet</u>	<u>Total</u>
1981	1137	22	1159
1982	1592	36	1628
1983	1956	33	1989
1984	2281	32	2313
1985	2533	25	2558

A change in the nominal rate under the existing severance tax from 12.25 percent to about 22 percent would raise sufficient revenue to cover Ch. 21 revenues.

The current severance tax formula allows for a tax rate modification based roughly on the marginal costs of production (see Table III). If this were eliminated, leaving a flat percentage of value severance tax, the required percentage of value would be between 20 and 18 percent, falling to the lower level in the last year of the backstop period (see Table IV). The fact that the power of a flat rate severance tax (no economic limit factor) grows over the backstop period is an important characteristic that could make it very useful in combination with a property tax on reserves, which shows the opposite tendency.

TABLE III

ANALYSIS OF OIL PRODUCTION TAX RATES

<u>Fiscal Year</u>	<u>Nominal Tax Rate</u>	<u>North Slope</u>		<u>Cook Inlet</u>	
		<u>Estimated Effective Rates</u>	<u>Indicated Economic Limit Factor</u>	<u>Estimated Effective Rates</u>	<u>Indicated Economic Limit Factor</u>
1981	12.25%	11.74%	.96	4.75%	.39
1982	12.25	10.79	.88	4.13	.34
1983	12.25	10.57	.86	3.98	.32
1984	12.25	10.46	.85	3.81	.31
1985	12.25	10.13	.83	2.89	.24

Note: The economic limit factor reduces the tax variably to take account of differing costs. See A.S. 43.55.

TABLE IV

NEEDED INCREASES IN OIL PRODUCTION TAX RATE
TO OFFSET CH. 21 REVENUES
BY YEARS
(Dollar Figures in Millions)

<u>Fiscal Year</u>	<u>Est. Ch.21 Revenues</u>	<u>Total Oil Production Tax Revenues</u>	<u>Required Nominal Rate With E.L.F.</u>	<u>Required Effective Rate</u>
1982	1303	1627	22.05%	19.73%
1983	1541	1989	21.68	19.07
1984	1783	2313	21.68	18.58
1985	2141	2558	22.54	18.10

The principal problems with using the severance tax as a stand alone backstop are the potential political and legal liabilities associated with rates this high, and the potential spillover effects, mainly related to what has been termed the premature shutdown effect. A severance tax of 19 percent (effective rate) combined with a 12.5 percent royalty would mean that any production not earning over 68.5 percent of its cost would be shut down. These difficulties are much less significant at the lower rates possible if the severance tax were used in combination with another tax.

There are several variations on the severance tax which we have also considered. One of these, a state windfall profits tax modeled on the federal tax of the same name, would tax, say, 15 percent of the value of each barrel that exceeds a base price, which escalates with inflation. If the price of oil and the general price level were frozen at today's levels, a state windfall tax of 15 percent would be identical to a flat rate severance of about 6 percent.

The difficulty with a state windfall tax would come if oil prices don't rise as fast as general inflation. The high leverage of the tax would mean a rapid fall in tax revenues. In any event, certainty of effect is clearly a problem with the tax.

A State windfall profits tax might be considered by a court or Congress as simply a severance tax increase, and therefore might carry the same legal and political risks as a high severance tax rate. Additionally, it should be de-

terminated whether an argument might be raised that the states are preempted by Congress from enacting a windfall profits tax.

Income Tax. The use of a new income tax to backstop Ch. 21 would probably require a return to some sort of apportionment formula. If that formula were the three factor one contained in A.S. 43.20, which the plaintiffs assert is the only correct one to use, the result is an evident lack of fiscal horsepower. Some have suggested that a roughly accurate rule of thumb is that the traditional three factor formula would raise about one seventh the revenues of Ch. 21.

The collections of any apportioned income tax depend on factors beyond the borders of Alaska, and would vary widely among producers who have very similar holdings in Alaska, depending on the vicissitudes of their business activities outside the State. This is why "rules of thumb" are so frequently used in estimating income tax revenues from apportionment taxes. Clearly, the apportionment taxes are not the best with respect to certainty of effect.

Using a non-traditional apportionment formula such as a one or two factor formula can increase the percentage of Ch. 21 revenue that might be raised, but in no case that we have seen proposed has the level exceeded 50 percent, assuming the same tax rate.

All of these non-traditional apportionment systems would probably be challenged by those who are now litigating

Ch. 21 on many of the same grounds and would carry some legal risk. Although an Iowa one factor formula was recently sustained by the U.S. Supreme Court the court was closely divided.* As a result, the state cannot take complete comfort in a non-traditional apportionment formula.

A property tax on reserves has almost enough fiscal horsepower by itself to cover Ch. 21 revenues. Table V shows the tax rate that would be required to protect current Ch. 21 revenues.

TABLE V

RESERVES TAX RATES REQUIRED
TO RAISE CH. 21 REVENUES

<u>Fiscal Year</u>	<u>Ch. 21 Revenues</u>	<u>Prudhoe Field Valuation Base Case (Billions)</u>	<u>Required Tax Rate</u>
1982	1303	48.6	2.68%
1983	1541	47.5	3.24
1984	1783	45.6	3.91
1985	2141	44.5	4.81

Base Case Assumptions:

1. Discount Rate = 19%
2. Federal Windfall Profits Tax continues in effect until December 31, 1991.
3. Other assumptions consistent with revenue estimates.
4. Prudhoe field only.

We feel confident that the higher tax rates would be legally sustained, but believe it appropriate to avoid going beyond

* Moorman Manufacturing Co. v. Bair, 437 U.S. 267 (1978).

the usual range of property tax rates in the United States.

In addition to a relatively high horsepower, the property tax on reserves has the advantage of being simple in concept. Alaska had such a tax from 1975 to 1977, with both revenue officials and the reserves owners knowledgeable about how the tax would work. A property tax on reserves does have some disadvantages. As Table V clearly shows, it tends to loose fiscal horsepower as the years pass, and as the field is depleted. A tax rate that covers current Ch. 21 revenues quite comfortably in FY 1982 would fall far short in subsequent years.

Another problem with a tax on reserves is that its yield is very sensitive to decisions made in the assessment process. For example, an increase in the discount rate from 18 percent to 19 percent will, as shown in Table VI, reduce the valuation and the yield by almost 10 percent.

PRUDHOE BAY
PRELIMINARY FIELD VALUATION RESULTS

Current Severance Tax Rates
Windfall Profits Tax Continues through CY 1993

<u>Appraisal Date</u>	<u>Fiscal Year Payment Date</u>	RESERVE VALUE IN BILLIONS		
		<u>20% Discount Rate</u>	<u>19% Discount Rate</u>	<u>18% Discount Rate</u>
1/1/81	1982	41.8	45.9	50.7
1/1/82	1983	40.2	44.2	48.9
1/1/83	1984	37.9	41.8	46.2
1/1/84	1985	36.1	39.8	44.2
1/1/94	1995	8.3	9.8	11.7

The discount rate which we have used in our base case calculations is 19 percent, one percentage point higher than Alaska's assessors used in 1975. This is reasonably conservative, and is based in part on conversations with reserves assessment experts in Texas.

IV

BACKSTOP MECHANISMS

A backstop mechanism is the means by which a tax or combination of taxes discussed above will prevent tax revenues from falling below current desired levels in the event that Ch. 21 is declared invalid either in whole or in part.

Arguably, one backstop mechanism is already in place--A.S. 43.20 (The general corporate income tax). The same act which imposed the new corporate income tax (Ch. 110 SLA 1978) on oil and gas production and pipeline transportation corporations also removed the imposition of A.S. 43.20 on those same corporations. If a court struck down Ch. 21 in its entirety, A.S. 43.20 could be revived. Once revived, it could backstop at least some of the revenue loss.

The State's general savings clause--A.S. 01.10.100--does not cover this type of situation. So there is no certainty that A.S. 43.20 would be revived. There is, however, legal support for the proposition that if a repealing act is found invalid, the repealing section also falls and the repealed section is revived. This is especially held true if the invalidated act was a substitution for the repealed act. Using this analogy A.S. 43.20 would be revived as to Ch. 21 taxpayers if the court struck down Ch. 21 in its entirety. Whether the revived A.S. 43.20 could then be retroactively imposed would depend upon whether the retroactive imposition was constitutionally permissible and

whether the assessments would be barred by the State's statute of limitations on assessments. As analyzed under the court tests previously discussed, a defensible argument could be made to support the retroactive imposition and assessment.

A more difficult situation is presented if a court only strikes down a portion of Ch. 21. A.S. 43.20 probably would be revived only if it could be easily incorporated with the remaining portion of Ch. 21 without overlap, and if a court were to find a clear legislative intent for such revival. It is probably unlikely that a court would fashion a new tax by piecing together portions of the two taxes.

In any event, if a court were to invalidate Ch. 21, a revived A.S. 43.20 would only backstop a small portion of the lost revenues.

In connection with the primary criteria already discussed, the backstop mechanism must itself withstand legal challenge, and operate to protect current expected revenues under all possible litigation outcomes. The backstop mechanisms should also satisfy, to the extent possible, the secondary criteria, such as avoiding spillover effects and overcollecting revenues.

We have analyzed a number of possible backstop mechanisms. The following three general approaches which show the most promise are:

1. A new tax or combination of taxes could be imposed and collected concurrently with the oil and gas corporate

income tax. The money collected from such tax or taxes would be available to fund government programs at a level established in the Joint Statement. The proceeds from the oil and gas corporate income tax could then be appropriated to an escrow account until the validity of the oil and gas corporate income tax is finally determined.

2. A new tax or combination of taxes could be triggered into effect by some future event such as a final court determination that Ch. 21 is invalid.

3. A new tax or combination of taxes could be imposed currently with a credit allowance between Ch. 21 and the new tax so that there would be no cumulative collection of both taxes.

Escrow Option. The adoption of a new tax to raise currently expected revenues and the escrowing of Ch. 21 revenues until the validity of A.S. 43.21 is determined is one back-stop mechanism. Other variations of this option could be established such as escrowing the new tax rather than A.S. 43.21 revenues. The former approach, however, is probably more defensible since the new tax would have a clearly permissible public purpose--collecting revenues to fund State public programs. Similarly, the State could legitimately escrow tax monies which were under court challenge.*

* In speaking of escrowing Ch. 21 revenues, we don't mean to imply that the legislature could mandate the escrow of revenues and bind future legislatures. This could be argued as a dedication of revenues prohibited by Art. IX, §7 of the Alaska Constitution. Successive legislatures could, however, appropriate the revenues collected under Ch. 21 to an escrow account.

Depending upon the tax base or bases chosen, this mechanism could fully backstop Ch. 21 revenues at risk. Likewise, the use of this mechanism is legally defensible assuming that the new tax is levied for the legitimate purpose of obtaining revenue to fund State public programs. The State clearly has the authority to impose taxes necessary to fund public programs and is not required to spend funds which it might have to refund as a result of a court challenge.

This option is not without drawbacks under the criteria which have been identified. First, although this mechanism could provide a complete backstop for revenues that might be lost, it also has the potential of collecting revenue beyond currently desired levels. Under this mechanism, if Ch. 21 were invalidated in total, the State would be able to refund Ch. 21 taxes and still be able to fund State programs without overcollecting. On the other hand, if Ch. 21 totally withstands challenge or is invalidated only in part, the State may have exceeded its desired level of revenue collection.

Second, because the State would be collecting both the new tax and Ch. 21 revenues with the potential of collecting beyond the desired revenue level the overall tax burden would be increased. This increased tax burden could create spillover effects such as altering taxpayer decision making and effecting future exploration and development.

Triggering Option. Another mechanism available to

backstop A.S. 43.21 revenues is the enactment of a tax or combination of taxes with an effective date contingent upon some future event. For example, a tax could be enacted which would be imposed retroactively upon a final court decision invalidating Ch. 21. Other variations of this option could be designed all involving a tax which is triggered into existence upon the happening of a future event.

Depending upon the tax base or bases chosen, this mechanism is capable of backstopping the total amount of Ch. 21 revenues which are at risk. With regard to the legality of this option, it should first be observed that it is not uncommon for legislation to be made effective upon the happening of some future event. The retroactive operation of such an option, however, does raise legal questions. As discussed previously, there are limits to the authority of the legislature to impose taxes retroactively. A court could determine that the enactment of the contingent tax was sufficient notice to taxpayers that a tax might be imposed, to be within permissible limits of retroactivity. This result, however, is not free from doubt.

Like the escrow mechanism, this option also has the potential for overcollecting revenues beyond the State's revenue goals. This stems from the practical problem of drawing the triggering mechanism so as to cover all the potential outcomes of the lawsuit. If a court were to strike down Ch. 21 in its entirety, this backstop mechanism could become effective to collect the level of revenues

needed by the State. If, on the other hand, only a portion of Ch. 21 revenues are lost from an adverse decision, a full collection under the new tax might be automatically triggered. Some tailoring of the mechanism might be made which could accomodate various levels of revenue loss but precision to meet every circumstance is probably not possible.

Credit Option. A third mechanism which could be used to backstop Ch. 21 revenues would be the imposition of a new tax or taxes which would be creditable against Ch. 21 or a new tax or taxes to which Ch. 21 tax payments could be credited.

This tax mechanism could be used with any tax base and assuming that tax base had sufficient horsepower is capable of backstopping the total amount of Ch. 21 revenues at risk.

Adopting a new tax which is creditable against other taxes or for which other taxes can be credited is a legally defensible taxing system. First of all, the new tax or taxes could be enacted for the purpose of collecting revenues necessary to fund public programs. Additionally, the legislature could legitimately decide to allow a tax credit for the purpose of avoiding a double taxation effect from the imposition of both an income tax and another tax which might be imposed with respect to the same property or activities. The use of credits to avoid double taxation effects is a commonly accepted taxing practice.

Unlike the overcollection potentials of the other mechanisms, the use of credit system comes the closest to col-

lecting the amount of revenues put at risk while at the same time not overcollecting beyond the revenue goals established by the legislature. For example, if Ch. 21 revenues were allowed as a credit against a new tax, and a subsequent court decision invalidated Ch. 21 in whole or in part, the refund of A.S. 43.21 revenues would be offset by an increase in the new tax by reason of the reduced credit.

Because the credit system minimizes the possibility of overcollecting, the overall tax burden should remain relatively the same. That in turn will serve to minimize spillover effects that might accompany an overall increase in tax burden.

By imposing the new tax immediately with a credit you also avoid the potential retroactivity problems associated with a triggering mechanism.

It is conceivable that taxpayers would cry foul to the use of any backstop mechanism since it would mean tax changes enacted during the pendency of their challenge of Ch. 21. Presumably these taxpayers would claim that the tax changes were made to punish those who challenged Ch. 21. If such were the case, it would certainly raise a serious legal question. However, as we have stated, a backstop can be supported by a clearly permissible public purpose--raising revenue necessary to fund public programs. The legislature having made a policy decision as to the level of needed public programs has authority to enact taxes necessary to raise revenues to support those programs. In making

these decisions the legislature certainly has the right to take into account the certainty of its revenues and the debts that might reduce its revenues. The legislature can adjust its tax structure to ensure sufficient revenues to meet its public programs.

CONCLUSIONS AND RECOMMENDATIONS

The contract under which this study was carried out specified that we should identify "options for further consideration." This must, if only by omission, identify those that do not deserve further consideration. We are uncomfortable with this latter implication, since we are unprepared ourselves to rule out the possibility that policy concerns of which we are unaware, or new facts might cause us to change our minds. Nevertheless, we are reasonably confident that the options identified below will, after further work, prove to be those most likely to meet the objectives of the Joint Statement, and the criteria discussed above.

1. The first issue is whether to seek a permanent replacement of Ch. 21 while the litigation challenging it is still pending, or to protect Ch. 21 revenues with a backstop, making revisions to Ch. 21 only in the event the State loses. We believe that the latter course is preferable because we have not identified any option which has the degree of revenue, legal and political security required to be a permanent replacement. As stated earlier, the fiscal and legal security of a replacement must be close to absolute, since a new tax is not the second and reinforcing line of defense that would be created by a backstop; it is a new first line of defense which must stand alone.

As stated succinctly by the Governor in his budget message:

"Motivation for [this] litigation centers more on fiscal principal than legal principal. . ."

Consequently, any attempt to collect the same level of revenue by other means will have the same result--a lawsuit.

A replacement for Ch. 21 might still be in order if it could be demonstrated that the replacement was more secure than the combination of Ch. 21 with a backstop. This demonstration has not been made. If it were to be made, legislators would need further to decide whether the policy issues opened up by consideration of a replacement (as opposed to a backstop) could be resolved in the time available.

2. The backstop tax that appears to best meet the goals of the Joint Statement is a combination of a new severance tax and a reserves tax or a reserves tax by itself. A 15 percent effective rate severance and a 2.5 percent reserves tax or a four percent reserves tax (as shown in Table VII), would have the necessary fiscal horsepower to cover current as well as past Ch. 21 revenues at risk. It also appears to minimize legal risks, potential congressional reaction, and spillover effects. We recommend that the fiscal and economic analysis of these options be refined, and that the proposals be put in more concrete form.

3. With respect to a backstop mechanism, we recommend that further attention be focused on the credit option. Our preliminary analysis indicates that this option will effectively backstop Ch. 21 revenues with the tax types recommended. It also appears to minimize the legal risk, over-

collection potential, and spillover effects.

If this option is chosen, analysis of variations on the credit mechanism and their effects would be appropriate.

TABLE VII

REVENUE ESTIMATES
FOR RECOMMENDED OPTIONS
(Millions of Dollars)

<u>Fiscal Year</u>	<u>Ch. 21 Revenue</u>	<u>4% Reserves Tax</u>	<u>15% Effective (16.67 Nominal) Plus 25 Mill Reserves Tax</u>
1982	1303	1944	1801
1983	1541	1900	1903
1984	1783	1824	1973
1985	<u>2141</u>	<u>1780</u>	<u>2033</u>
Total	6768	7448	7710

Notes: North Slope reserve property tax estimates only.
Cook Inlet valuations would increase these amounts.
North Slope valuation assumes 19% discount rate and
federal Windfall Profit Tax ending December, 1991.

APPENDIX A

JOINT STATEMENT ON OIL TAXES ISSUED BY THE STATE ADMINISTRATION AND THE LEGISLATIVE LEADERSHIP ON MARCH 18, 1981

Governor Jay Hammond and the leadership of both houses of the Legislature are united in an effort to arrive at the best course of action on pending oil and gas tax issues. Legal challenges by the oil industry have placed as much as one-third of the State's projected tax revenues in jeopardy.

Alaska's existing taxation and leasing policies currently provide significant incentives for petroleum exploration and development in the state. Hence, existing levels of taxation, stabilized since 1978, should remain stable at this time. On the other hand, any significant decreases in State oil and gas revenues appear both unwarranted and unsupported by the majority of Alaskans. The State's current level of taxation -- about one-sixth of the value of Prudhoe Bay production -- provides that both the oil companies and the federal government will receive greater shares of Alaska's wealth than will Alaskans. Accordingly, any greater percentage granted the former at the expense of the latter would be inequitable.

Both the Governor and the legislative leadership are determined that through their mutual efforts, a sound strategy for protecting oil and gas revenues will be found. All agree that any changes which would give large sums of money to the oil industry at the expense of the people of Alaska are unacceptable. The Prudhoe Bay bonanza will not last

forever. We must make use of those revenues now through investments such as hydroelectric power, renewable resource development, and permanent fund contributions which will provide for our future.

APPENDIX B

A NOTE ON RESEVOIR VALUATION METHODOLOGY

Reservoirs are generally appraised the same way as other income earning property; the possible future income from the reservoir is estimated and discounted back to the present at a rate that represents the return expectations of an hypothetical buyer. This was the method the State used to value the Prudhoe Bay field in 1975 and we used the same method in this study.

First, an appraiser needs a solid engineering estimate of the size, hydrocarbon content, and likely annual production rates of the field. For the Sadelrocheit Reservoir, we used the latest Alaska Oil and Gas Conservation Commission forecasts. For the Kuparuk and Lisburne fields, we relied on estimates provided by the Petroleum Revenue Division.

Next, we reviewed estimates of the future costs, both capital and operating, needed to purchase, build, install, and operate all of the equipment in the field. As the valuation method requires, we do not include past costs or financing expenses. Estimates of future costs were developed by H.K. VanPoolen Associates, Inc. in 1979, updated by us and the Legislative Finance Division to reflect recent changes and price increases.

A third major step is to forecast future prices for reservoir products and then net them back to the field. For these estimates, we relied heavily on the sophisticated

PETREV forecasting model operated by the Department of Revenue. In general, these estimates suggest little "real" price increase for oil in the world markets and an average rate of inflation of about 10 percent. Wellhead prices, however, are expected to increase rapidly as the TAPS line lowers its per-barrel tariffs. The current average wellhead price of about \$25.00 is expected to rise to about \$30.00 next year. For gas, given the uncertainty of its transportation and wellhead value, we assumed a flat \$1.00 per MCF real price and sales beginning in fiscal year 1988.

Finally, with these decisions in hand, we scheduled the annual cash flows of the field. Using a computer, we estimated all of the production values, costs and expenses, royalties, excise, property and production taxes, and wind-fall profits taxes. Since valuations are traditionally based on estimates of before tax income, we did not include a calculation of State or federal income taxes.

The appraisal value is the sum of these annual net cash flows to the producers discounted back to the present at a rate chosen to fairly represent the alternative uses of capital. The choice of the discount rate is critical as the valuation is greatly affected by it. See Table VI for the effect of various discount rates on our preliminary valuations.

We learned from a discussion with personnel of the Texas petroleum appraisal firm of Prichard & Abbott that

they are proposing a State-wide 18% discount rate this year for valuing reservoirs in Texas. They believe this is a fair rate even though short term lending rates have been higher at the beginning of the year.

We believe any discount rate in the range of 18 to 20 percent to be reasonable for Prudhoe Bay and have picked 19 percent for purposes of forecasting property tax revenue. Here are some of the factors we considered:

1. The State, with advice from Prichard & Abbott, used 18 percent to prepare the 1975 property tax valuation of Prudhoe Bay. Although inflation and interest rates have jumped since then, all of the startup risks of the field and pipeline are behind us now. These factors, thus, tend to cancel out.

2. Large fields typically receive lower rates than small fields because of the inherent diversification coming from multiple wells and collection facilities. The fact that once collected, Prudhoe oil must then flow in a single pipeline a great distance to tidewater effectively eliminates this diversification effect.

3. Alaska's North Slope is a generally hostile environment traditionally accorded higher than average rates to compensate for extraordinary risks.

We believe our valuation estimate of \$48.6 billion for the Prudhoe Bay field is sufficiently accurate for use in the context of comparing alternatives to Ch. 21. Errors in the range of $\pm$ 10 percent may still exist due to the diffi-

culties in getting all data on the same basis. Although the State's Producer Benefits Model (P.B.M.) was once on a calendar year basis, it has been converted along with its data to perform fiscal year studies. To establish a January 1 appraisal date, we elected not to reconstruct back to calendar year reporting as would have been theoretically required.

With respect to the other factors most affecting the field's value, such as oil prices, we used the assumptions contained in the P.B.M.

Of the remaining factors that affect the valuation, the most important is the federal windfall profits tax of 1980. Because of the significance of these tax payments, the available calculation of their likely size, provided by the Department of Revenue, was used and the results of the model adjusted accordingly. The federal windfall profits tax is so significant that even the uncertain termination date of the tax may vary the valuation of the field by \$7 billion in the first year.

APPENDIX C

A NOTE ON DATA SOURCES

The time available to undertake this analysis did not permit us to develop independent revenue and cost estimates. In part, we relied on published and unofficial working papers supplied by the Department of Revenue. After reviewing their assumptions and procedures, and working with their data continuously for the 10 days, we believe it the best available for this purpose.

Estimates contained in this study are, to the extent possible, consistent with the Department of Revenue's assumptions and forecasts contained in their report "Petroleum Production Revenue Forecast, Quarterly Report, March, 1981." The concerns expressed in that report about the fallibility of "single point" predictions certainly holds for our work as well. At best, these estimates are only a consistent guide for comparison purposes.

Occasionally, we used unpublished data supplied by the Department, but only on a basis consistent with the same March, 1981 assumptions. This was the case for Table I, the figures for which were derived from work sheets supplied by the Petroleum Revenue Division.

Data for Table II was derived from page 9 of the aforementioned March, 1981 quarterly report.

The biggest difficulty that we found with data was to understand and keep consistent the reporting timetables. To

the extent possible, we have attempted to present estimates on a fiscal year basis, when funds will actually accrue to the Treasury. This wasn't always easy. Ch. 21, for example, is on a calendar year basis but provides for quarterly prepayments three out of four of which are actually received in the following fiscal year. Another example is the production tax which taxes monthly oil and gas production. However, the physical production is accounted for by the companies more than a month later which may fall into a different calendar or fiscal year. As a result, estimating a tax receipt often required calculating "pseudo-variables" which create an artificial event that would have occurred if production, liability and payment were all simultaneous. Table III's estimates of effective production tax rates employ this technique to calculate effective rates using production and tax estimates contained in the March, 1981 report.

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