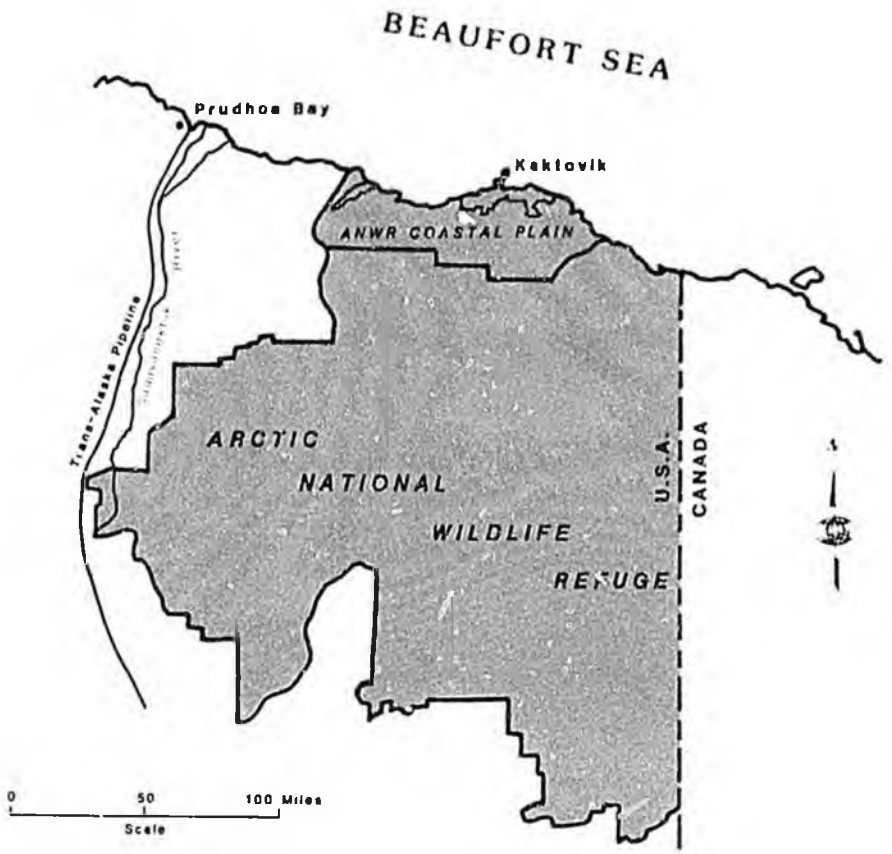
HB 118

FILE 1

An Alaskan View of ANWR



A Commonwealth North Report

About the Authors of this Report

Commonwealth North's ANWR Committee is made up of seventeen Alaskans, all of whom have had extensive experience in public and community service, both local and statewide. On the committee are four former members of the Alaska legislature, four former members of the governor's cabinet, a former Speaker of the House, three judges, and a retired general. Among them, they have a total residence in the state of 694 years, averaging 41 years each. Representing both Republicans and Democrats, business and government professions, these seventeen individuals reached unanimous conclusions on all of the material in this report.

— *Foreword* —

In February of 1987, the Board of Directors of Commonwealth North commissioned a committee to study the issues involved in opening the Arctic National Wildlife Refuge to oil and gas development. The charge given to the committee was to formulate a sound public policy position on ANWR and to work to build an Alaska consensus behind this position.

For 24 months, the Committee has tracked the issue, kept the Board apprised, participated in efforts to inform the public, and published a full-page newspaper advertisement in August of 1987 during the visit to Alaska of several Congressional committees (Appendix B).

Despite a considerable Congressional effort in 1988, legislation to open ANWR to oil and gas exploration and development was unsuccessful. However, a House bill that would have placed ANWR in a wilderness category and therefore completely off limits to energy production, also failed. During the debate several side issues often stole the limelight from the central issue. Those side issues included proposed land trades for tracts within ANWR, the State-Federal division of hoped-for royalties, and the conditions under which organized labor would assist with the passage of legislation.

In order to capture the experience, thinking and information amassed by this Committee, we have written this report. With President George Busn's strong support, as voiced in his first State of the Union address, 1989 holds new promise for the passage of favorable ANWR legislation. The information included here can help Alaska develop a unified, clear position on what a federal law to encourage oil and gas exploration and development in ANWR should include.

It is urged that the people of Alaska use these findings to further educate themselves on the ANWR questions. Their wisdom and energy is needed to achieve a favorable outcome to this issue, so vital for both the state and nation.

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The Alaska Statehood Act (Public Law 85-508 H.R. 7999) granted the fledgling state substantial lands to be claimed within 35 years of admission. 102,550,000 acres of vacant, unappropriated, unreserved land could be selected with no stipulation on usage. A qualification was a national defense withdrawal of approximately one-half of the state north and west of a line along the Porcupine River to the Yukon River to longitude W 160 to Holy Cross, to the mouth of the Kuskokwim River thence south to N 57 30'. Lands in this area could not be selected without specific approval of the President or his designated representative. The lands presently designated as the Arctic National Wildlife Refuge (ANWR) fall within the aforementioned national defense withdrawal.

In 1980, Congress changed the Arctic Range into a Refuge and expanded it to 19 million acres.

A 1960 administrative action established the Arctic National Wildlife Range as a federal conservation unit, originally covering 8.9 million acres in northeastern Alaska. In 1980, Congress addressed the boundaries of the Range and the land management principles which should govern its future use in the Alaska National Interest Lands Conservation Act (ANILCA). In so doing, Congress doubled the size of the conservation unit to 19 million acres and redesignated the greatly expanded area as the Arctic National Wildlife Refuge (ANWR).

ANWR borders the Arctic Ocean to the north. Its western boundary lies 55 miles east of Prudhoe Bay and the trans-Alaska pipeline. Its eastern extremity is the Alaska-Canada border and its southern boundary tails off well down the southern slopes of the Brooks Range into the Yukon River drainage. It is important to note that in ANILCA, Congress also designated 8 million acres (approximately 45% of the expanded ANWR) as Wilderness in accordance with subsection 3(c) of the Wilderness Act. Under this designation, no development activity of any kind is permitted.

1.5 million acres of ANWR were identified as having high oil and gas potential.

Congress identified an additional 1.5 million acres (approximately 8% of ANWR's total acreage) as having high oil and gas potential. This area, in the western portion of ANWR's coastal plain, is referred to in ANILCA as the "1002 Coastal Plain Area." It was singled out for further study of its oil and gas and wildlife resources to assist the Congress in a subsequent decision as to whether it should be:

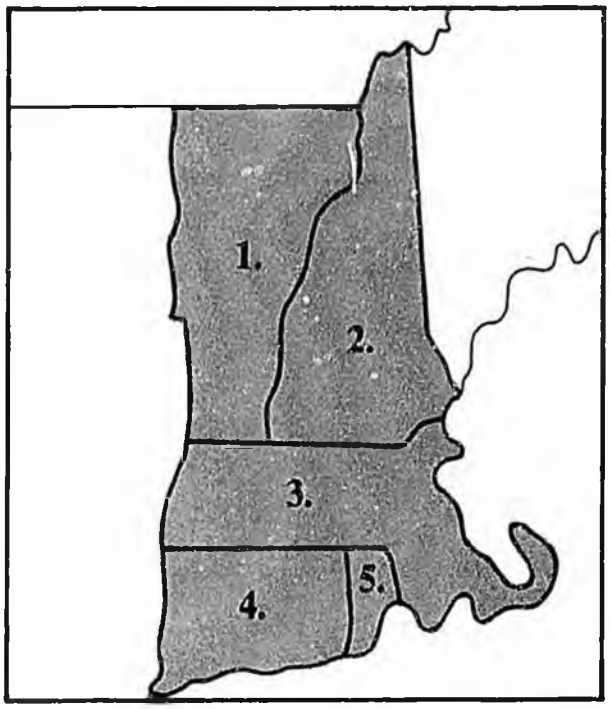
ANWR
19 million acres

KAKTOVIK INUPIAT CORPORATION/ARCTIC SLOPE REGIONAL CORPORATION LANDS - 92,000 Acres

ANWR COASTAL PLAIN
Section 1002 Study Area - 1.5 Million Acres

ANWR WILDERNESS AREA
8 Million Acres

At issue is oil development in the Coastal Plain (or 1002 area) which represents 8% of ANWR.



1.	New Hampshire	5.9
2.	Vermont	6.1
3.	Massachusetts	5.3
4.	Rhode Island	.7
5.	Connecticut	3.2
		21.2 million

ANWR is almost as large as five of the East Coast states combined.

1. **opened to oil and gas development;**
2. **managed as a Wilderness area; or**
3. **subjected to some other alternative management regime.**

The most promising onshore frontier for major oil and gas prospects in the entire nation.

The oil potential of this area goes beyond mild speculation. It is generally agreed that the 1002 Coastal Plain area in ANWR contains the most promising onshore frontier area for major oil and gas prospects in the entire nation. Since 1980, however, all public lands in the Coastal Plain have been withdrawn from the stipulations of the Mineral Leasing Act and no development may be undertaken on the Coastal Plain until expressly authorized by an act of Congress.

The Coastal Plain also contains important fish and wildlife resources. These resources were included in the 1002 study conducted by the U.S. Fish and Wildlife Service within the Department of the Interior.

The Section 1002 Report

Title X of ANILCA authorized and directed a number of studies and reports on the oil and gas potential and fish and wildlife resources of the Coastal Plain of ANWR. Section 1002(h) of Title X directed the Secretary of the Interior to prepare a report together with his recommendations "...with respect to whether further exploration for, and the development and production of, oil and gas within the Coastal Plain should be permitted..."

A 5-year study by the U.S. Fish and Wildlife Service concluded that oil and gas leasing should be allowed.

The U.S. Fish and Wildlife Service completed the study, and the Secretary's report was submitted to the Congress on April 20, 1987. The 5-year study concluded that oil and gas leasing should be allowed, and, inspite of some displacement, the wildlife populations on the Coastal Plain would not suffer major disruption or harm. Congress was called upon to review the Secretary's report and to decide the future management regime that will govern activities on the ANWR Coastal Plain. Congress responded with a lengthy series of hearings.

In 1988, legislation to open ANWR passed the Senate Energy Committee and the House Merchant Marine and Fisheries Committee. No bill, however, reached the floor of either house.

Alaskans generally applauded this legislation but became concerned when they discovered that some of the provisons of these bills ran counter to and in conflict with the promises and pledges made to the State of Alaska at the time it entered the Union.

For example, the Constitution of Alaska states that "...it is the policy of the state to encourage the settlement of its land and the development of its resources..." (Article VIII). It is clear that the Statehood Act intended land to be made available to the new state, and its natural resources were meant to be the basis of its economy.

A growing list of Congressional legislation and federal administrative actions since Statehood have been seen by many Alaskans as thwarting the intent of the Statehood Compact. If legislation to open the ANWR Coastal Plain for oil exploration is not carefully drafted, these abuses will continue, raising grave constitutional issues.

Unless ANWR legislation is carefully drafted, grave constitutional issues will be raised.

Chapter 2 — ANWR and the Environment

As the U.S. Fish and Wildlife Service was finishing the 1002 report, certain elements of the environmental movement marshalled their forces to discredit it. Most celebrated of the early opposition arguments focused on the fate of the Porcupine caribou herd, one of 20 caribou herds in Alaska. The Porcupine herd spends much of the year in Canada but often calves in the 1002 area.

The Porcupine caribou herd chose not to calve in the 1002 area in 1988.

Governor Steve Cowper embraced the idea that a "core calving area" be set aside for further study. Though disputed by many biologists, this concept defused the caribou issue in Congress. This strategy was opposed by the oil industry because of their successful record in Prudhoe Bay regarding wildlife, especially the Central Arctic caribou herd. Biologically, no such calving area exists, they argued.

Adding to the credence of that argument, the herd chose not to calve in the 1002 area in 1988. When the militant anti-ANWR groups realized that Congress was no longer listening to their claims, they shifted the debate from caribou to other real or perceived concerns.

From the outset, some conservation groups took a more balanced view of the Arctic Coastal Plain, perhaps because the area is nearly flat in topography, offers little scenic beauty except for a few days in early summer, and for anyone who knows the area first hand, ranks far below many other wildlife habitat areas both in Alaska and throughout the United States.

The topography of ANWR's Coastal Plain is flat and unforgiving, and the wildlife population sparse.

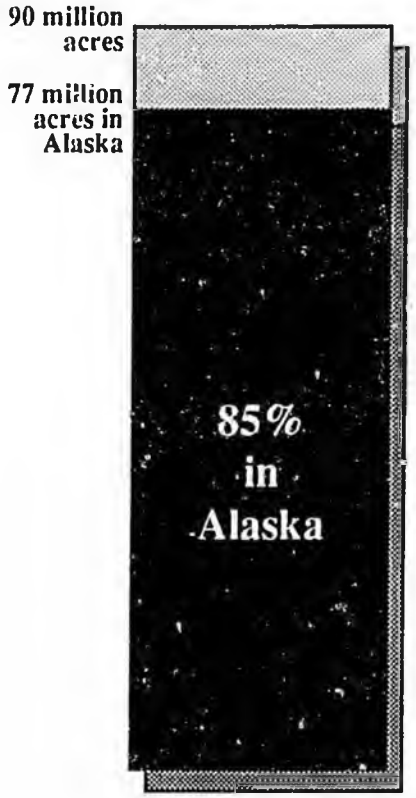
The Wilderness Society, however, was adamant in its opposition to resource extraction in the 1002 area because of its commitment to a "land ethic." Their spokesmen placed the sanctity of lands which experience a minimum of human activity above all else. This group launched a nationwide campaign, including a March 1988 fund-raising solicitation which made the following claims:

> "(The Arctic Coastal Plain is) an American Serengeti teeming with wildlife."

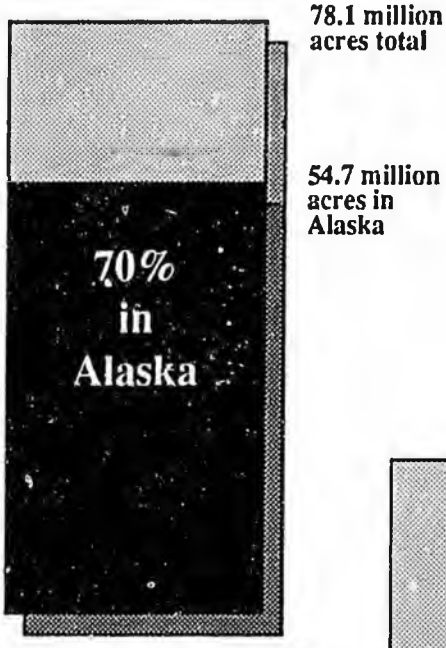
Editors' Note: The wildlife population estimates made by the USF&W Service in the 1002 report indicated the following:

Most of Alaska is already off limits to resource development.

Alaska leads the nation in National Parks, Wildlife Refuges and designated Wilderness



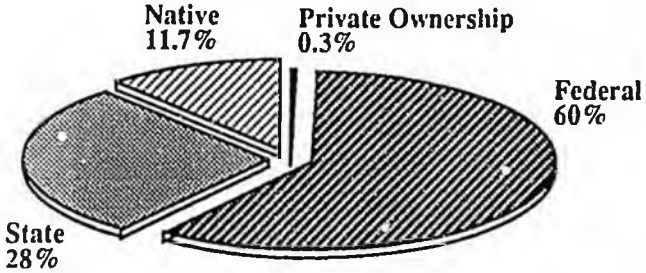
U.S. Fish & Wildlife Service Refuges



National Park Service Parks and Monuments

Wilderness Areas in U.S.

Who owns Alaska's 378 million acres?



Source: Alaska Resource Development Council

Source: U.S. Department of the Interior

dens 1-2. Birds and waterfowl listed were geese 105,000, ducks 35,000, swans 400-500, golden eagles 25-75, peregrine falcon eyries 2 (formerly occupied).

"The last untouched piece of America's Arctic Coastline that is not already in the hands of BIG OIL."

Less than 10% of America's Arctic coastline has been put up for lease for oil exploration.

Editors' Note: Less than 10% of America's Arctic coastline, from Pt. Hope opposite Siberia, West to the Canadian border, has been put up for lease for oil exploration.

"An unparalleled national treasure will be irretrievably lost."

Editors' Note: The oil reservoir beneath Prudhoe Bay is already two-thirds depleted. Once the oil and gas have been produced, there is little motivation for people to remain living in those conditions. Within a few generations, this area will be returned to wilderness.

"Expected output would only average about 2% of the nation's demand for oil over the life of the field."

Editors' Note: Until wells are drilled no one will know the dimension of the oil reserves, if any, beneath the 1002 area.

"Would we dam the Grand Canyon to generate electricity or tap Old Faithful for its geothermal power?"

Only a first-hand view can help Americans decide the aesthetic values of ANWR.

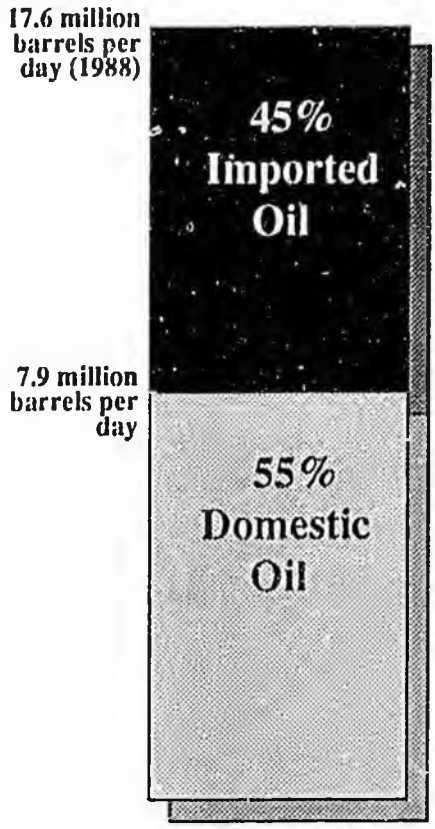
Editors' Note: Only a first-hand view of the coastal plain can help Americans decide whether it ranks in beauty and importance with the Grand Canyon and Old Faithful. Most old Arctic hands describe it as treeless, nearly flat topography, subjected to 60 to 70 degrees below zero temperatures in mid-winter and clouds of voracious insects in the summer.

"Interior Secretary Hodel even claims our national security is at stake. This claim is nonsense!"

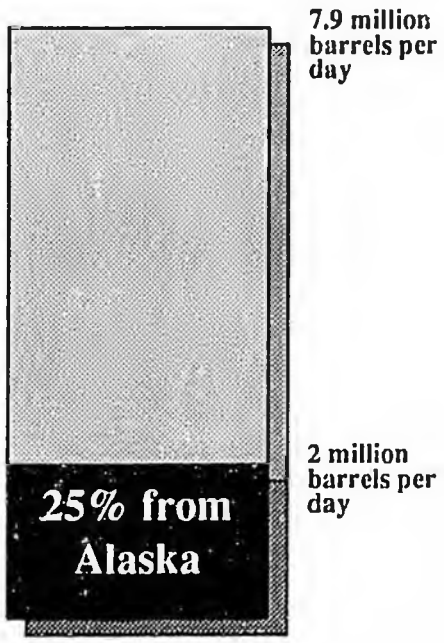
Editors' Note: North Slope oil accounts for 25% of all U.S. domestic output. The reader must decide whether this is a national security issue.

The previous month, the Sierra Club ran an ad in a national magazine which included the following:

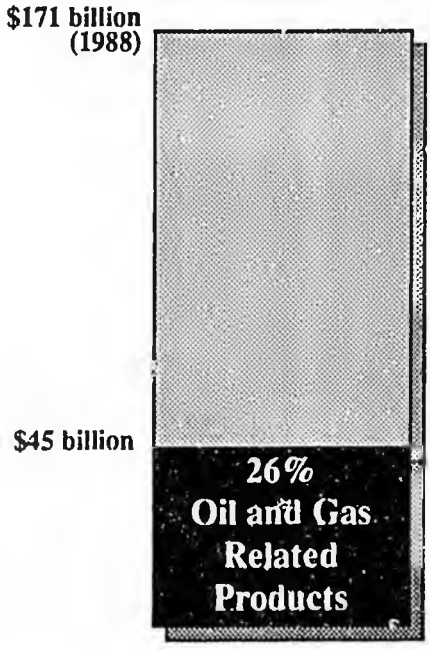
Is ANWR a national security issue? You decide.



Daily U.S. Oil Consumption



U.S.Domestic Oil Production



U.S. Trade Deficit

Source: Alaska Oil & Gas Association

"In Alaska there is a place as magnificent and rare as the Grand Canyon."

"Approval to drill will destroy what is left of Alaska's north coast."

— Excerpts from Sierra Club ad, February '88, *Modern Maturity Magazine.*

Many Congressmen flew to Alaska, toured the ANWR area and returned with first-hand experiences far different from the rhetoric of the wilderness advocates.

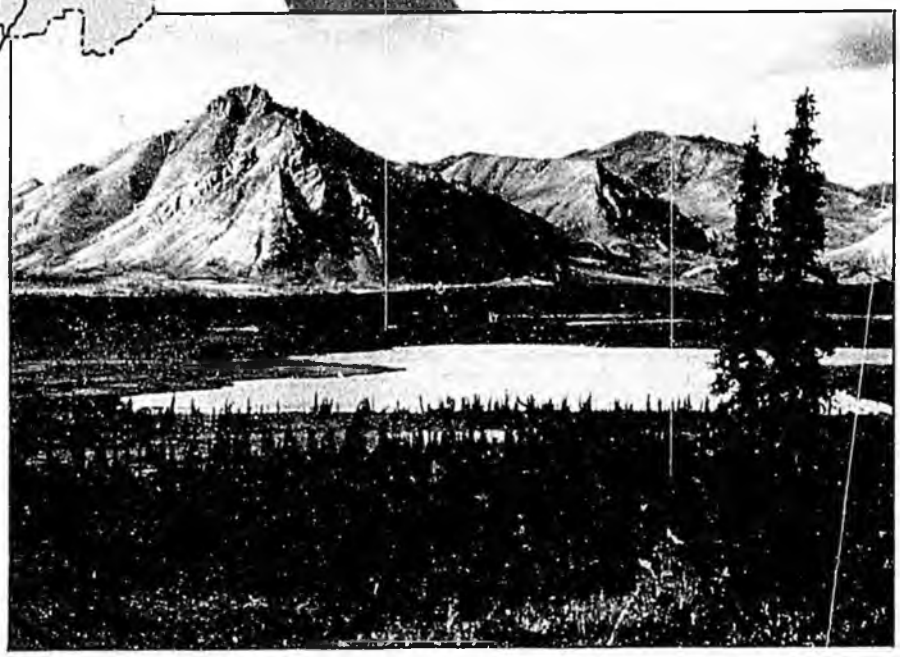
These hyperboles created a backlash amongst the members of the U.S. Congress serving on the committees addressing the ANWR issue, undermining the extremist anti-ANWR position. Many Congressmen flew to Alaska, toured the ANWR area and returned with first-hand experiences and vivid memories far different from the rhetoric of the wilderness advocates. Reasonable minds in Congress, the media, and the American public recognized that the oil industry has done an outstanding job of caring for the North Slope environment during the development of Prudhoe Bay, Kuparuk, and more recently the Lisburne and Endicott fields.

Resource development, wildlife and environmental protection can go hand in hand.

These examples have demonstrated that resource development, wildlife and environmental protection can go hand in hand.

(right) ANWR's 1.5 million acre coastal plain (the 1002 area) is flat and treeless and may contain vast oil and gas reserves. *(photo courtesy of U.S. Fish and Wildlife Service)*

There are two ANWR's



(right) The Brooks Range is part of a 9 million acre designated Wilderness within ANWR. This beautiful area is already completely off limits to resource exploration and development. *(photo courtesy of U.S. Fish and Wildlife Service)*

The Statehood Compact

The Alaska Statehood Act is a compact between Congress and the people of Alaska.

The Statehood Compact theory maintains that the Alaska Statehood Act is more than an act of Congress. Rather it is an agreement or contract between the United States and the people of Alaska. The act, in accordance with its terms, had to be ratified by the people of Alaska. A strict interpretation of the Compact Theory would hold that the Statehood Act (or compact) cannot be amended by Congress without the approval of the other party to the compact, the people of Alaska. The theory generally accepted is that while it can be amended, the Act cannot be amended to diminish the rights of the people of Alaska without their consent. This theory has been affirmed by the U.S. Supreme Court in at least one case, a case from Wisconsin, Beecher v Wetherby 95 U.S. 515 (1877).

A bill which grants statehood is a grant which cannot be revoked, unless both sides agree.

Even the opponents of statehood for Alaska recognized the nature of the Act. Senator Hugh Butler from Nebraska, a vocal opponent of statehood for Alaska, said in debate on the bill:

> "A bill which grants statehood is not some minor piece of legislation, but is a major function of the national legislature. We cannot undertake to perform that function without reminding ourselves that we are asked to make a grant which cannot be revoked. We cannot, therefore, consider these bills as we would ordinary legislation, in the sense that ordinary legislation may be amended or changed in subsequent years as experience dictates."

The consent of the Alaska people is required

Current ANWR legislation includes a "Blackmail Clause."

That the above theory is not taken lightly was demonstrated by Section 604 of the Senate Energy Committee ANWR bill (S.2214) considered by the last Congress (1988). This section provides that: (1) any litigation testing the validity of the ANWR bill as enacted must be brought within 90 days; (2) should suit be filed, no lease sales in the area will be conducted until the litigation is decided and; (3) should there be a judicial decision invalidating any provision of the act, the whole act will be invalid. Taken together, this is referred to as the "Blackmail Clause." The Blackmail Clause is aimed at the provison of the bill which reduces the State's share of revenues from 90% to 50%. This provision is contrary to the Statehood Act which stipulates that royalties earned

When Alaskans ratified the Statehood Act, the promise of a 90% royalty share was clear.

Anchorage Daily Times

RECORD VOTE SEEN TOMORROW

Third Division To Become New Voting District

Seaton Urges Passage Of Statehood

Statehood Fate Hinges On 3-Way Referendum

Primary Voting Facts

Statehood Is Called Big Achievement

Body Found Near Hope

Nautilus Gets Cheering Welcome From New York

CAP PILOT ASSISTS IN FINDING LOST HUNTERS

Absentee Voting Ends

FWS Chief, Two Others Missing In Th...

Seaton Urges 'Yes' Vote

U.S. Shooter Tops Russians

OFFICIAL BALLOT

No. 72122

Special Election -- Proposition No. 1

Tuesday, August 26, 1958

Vote on the following proposition YES or NO

Mark "X" in the square below to designate your "adoption" or "rejection" of this proposition.

"(1) Shall Alaska immediately be admitted into the Union as a State?"

Vote for one.

☐ YES (Adoption)

☐ NO (Rejection)

new Statehood Act far exceed any ever made in any previous statehood bill."

6. "The act reaffirms Alaska's preferential treatment in receiving 90 per cent of all revenues from oil, gas and coal leasing on the public domain."

7. "...The additional costs of statehood will be more than offset by additional revenues made available to Alaska."

Seaton's speech tonight, to

from oil and gas developed on federal properties within Alaska be divided 90% to the state and 10% to the federal government.

The question of the 90-day statute of limitations may be regarded by the courts as unreasonably short. However, it would not be wise to have to litigate this issue, since if one loses, the merits of the case are not considered.

Congress also has the authority to include the non-severability clause, i.e. number (3) above. Congress, or any legislature generally, can decide that a particular bill will stand or fall as one bill, and that if one section is declared invalid, then the whole bill will be invalid.

It has been suggested that suit for injunctive and declaratory relief could be brought prior to enactment of the bill. While this may be of some political value, it is unlikely such an action would result in the relief sought. In addition to the questions discussed briefly above, it is extremely unlikely that any court would enjoin Congress from enacting into law any particular bill. This would clearly be an intrusion into the political and legislative process. Another way of describing the problem is that courts are reluctant to adjudicate issues before they are "ripe" for review.

Legislative proposal

A provision should be included in the ANWR bill to put the division of revenues section before the people of Alaska in referendum.

Since throughout the debate on the Compact Theory our counsel have argued that it prevents amendment without the consent of the people of Alaska, the authors of this paper propose that a provision be included in the ANWR bill that would put the division of revenues section before the people of Alaska in referendum. Such a provision might read as follows:

> "Congress finds that provisions contained herein amend the Alaska Statehood Act as to divisions of revenues from federal lands affected by this Act. Recognizing that the Alaska Statehood Act is a compact with the people of Alaska, this Act will not be effective until any such amendment is approved by the voters of the State of Alaska."

It should be clear that the intent is to have any such amendment apply only to lands covered by the bill. Furthermore, the Alaska people should be thoroughly informed that if they were to refuse to approve the royalty reduction section, then ANWR would not be opened until further review by Congress.

Amendment to ANWR bill, as proposed by Commonwealth North:

"Congress finds that provisions contained herein amend the Alaska Statehood Act as to divisions of revenues from federal lands affected by this Act. Recognizing that the Alaska Statehood Act is a compact with the people of Alaska, this Act will not be effective until any such amendment to the Statehood Act is approved by the voters of the State of Alaska."

This provision will serve three purposes:

(1) It will raise the level of the debate in Congress to a matter of principle and indicate to Congress we are ready to submit it to a vote in line with the Statehood Act's provision for 90/10.

(2) It will involve the people of the state in the very important issue of opening ANWR for development including the revenue issue.

(3) It will bring a much-needed recognition of the Compact Theory in this state and perhaps throughout the nation. This is an important precedent to set for future state-federal relations.

If Congress adopts an ANWR bill which violates the Compact, the Governor must file suit for injunctive relief.

Judicial remedy

If Congress adopts an ANWR bill without the amendment proposed above and with revenue sharing set at less than 90/10 in the bill, the Governor must file suit for injunctive relief. In addition, the Alaska legislature, this session, should pass a resolution to that effect.

The suit would ask for implementation of the ANWR statute to be enjoined until the people of Alaska have had the opportunity to vote on this issue. The suit would be based on the Compact Theory. Simultaneously, the state should schedule the referendum vote. If in the referendum the people approve the royalty reduction amendment to the Compact then the litigation would be dismissed. If the vote is negative then the state would move for permanent injunctive relief.

If a suit is filed, Alaska should schedule a referendum vote to let the people decide the royalty reduction issue.

It is also possible for a private party to bring the above mentioned suit, although the bill adopted may include a provision allowing only the State to sue. The standing of a private group, such as Commonwealth North, would be based on the Compact Theory and that the people of Alaska as a party to the Compact have a right to object to a unilateral attempt to amend the Compact. Such a move should also be done concomitant with an initiative drive to put the question on the ballot for 1990. Getting the question to qualify as an initiative will require approval of the state government. But even raising the issue will start a healthy debate on state-federal relations.

The 90/10, 50/50 or less issue

During the debate on Alaska Statehood in Congress one of the compromises made was a change in the way oil royalties would be

paid on oil discovered and produced on federal lands within the new state. The purpose of this compromise was two-fold.

First, it was determined that the new state would not be included in the benefits of the Federal Water Reclamation Funds at least to the extent other western states did. Forty percent of the royalties generated by federal oil development on federal lands is deposited into this fund to assist western states in the construction of federal water projects.

Alaska has abundant water resources and, at that time, saw no need for such assistance. Conversely, Congress feared the prospect of having to pay for flood control of Alaska's great rivers.

One of the major concerns during the debate on Alaska Statehood was the ability of the new state to create an economy upon which it could sustain itself.

Second, one of the major concerns of the Congress and Administration during the debate on Alaska Statehood was the ability of the new state to create an economy upon which it could sustain itself. Granting Alaska a greater percentage of federal oil royalties, at a time when Alaska had no proven oil reserves, was an easy Congressional compromise.

In a memo presented to the Senate Subcommittee on Public Lands, National Parks and Forests, July 14, 1987 by Assistant Attorney General for the State of Alaska, G. Thomas Koester, the state presented its position regarding this historic compromise.

> "Section 35 of the Mineral Leasing Act of 1920, 30 U.S.C. 191, governs the distribution of revenues from oil and gas leasing of federal public domain lands. Under that statute, 90% of those revenues are dedicated to the benefit of the states in which the lands are located. In the lower 48 states, this dedication takes the form of a direct grant of 50% of the revenues and deposit of an additional 40% in the Reclamation Fund, established under the Reclamation Act of 1902, 43 U.S.C. SS 372 et seq. Because Alaska is not covered by the Reclamation Act, Alaska receives the full 90% under the statute.

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> "This dedication of federal oil and gas revenues to the states represented a historic compromise in the history of public land law. Around the turn of the century, there was a major change in federal land policy. The traditional practice of federal land disposal to encourage development and western migration was abandoned, and a new policy of federal land retention was instituted. To compensate the states for this

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continued federal ownership, which in any case precludes economic development and in all cases precludes state and local taxation, Congress dedicated 90% of the mineral leasing revenues from those lands to the states.

"During Congressional consideration of statehood for Alaska, considerable attention was given to the distribution of mineral leasing revenues from federal lands in Alaska. The result of those lengthy deliberations was that the revenue distribution provisions of the Mineral Leasing act of 1920 were expressly incorporated into Section 28 (b) of the Alaska Statehood Act."

An agreement had been reached. Compromise had helped bring Alaska to statehood. Congress formally recognized Alaska as a new state with all the rights and privileges recognized in the Statehood Act. Congress also formally ratified the new state's Constitution and the people of Alaska, by popular vote, accepted the Alaska Statehood Act.

Almost from the beginning of the ANWR debate, Alaska's own Congressional delegation advised that it would be difficult for Alaska to retain its 90% share of oil royalties.

Are Alaskans, because of tough economic times, willing to forfeit their right as a state?

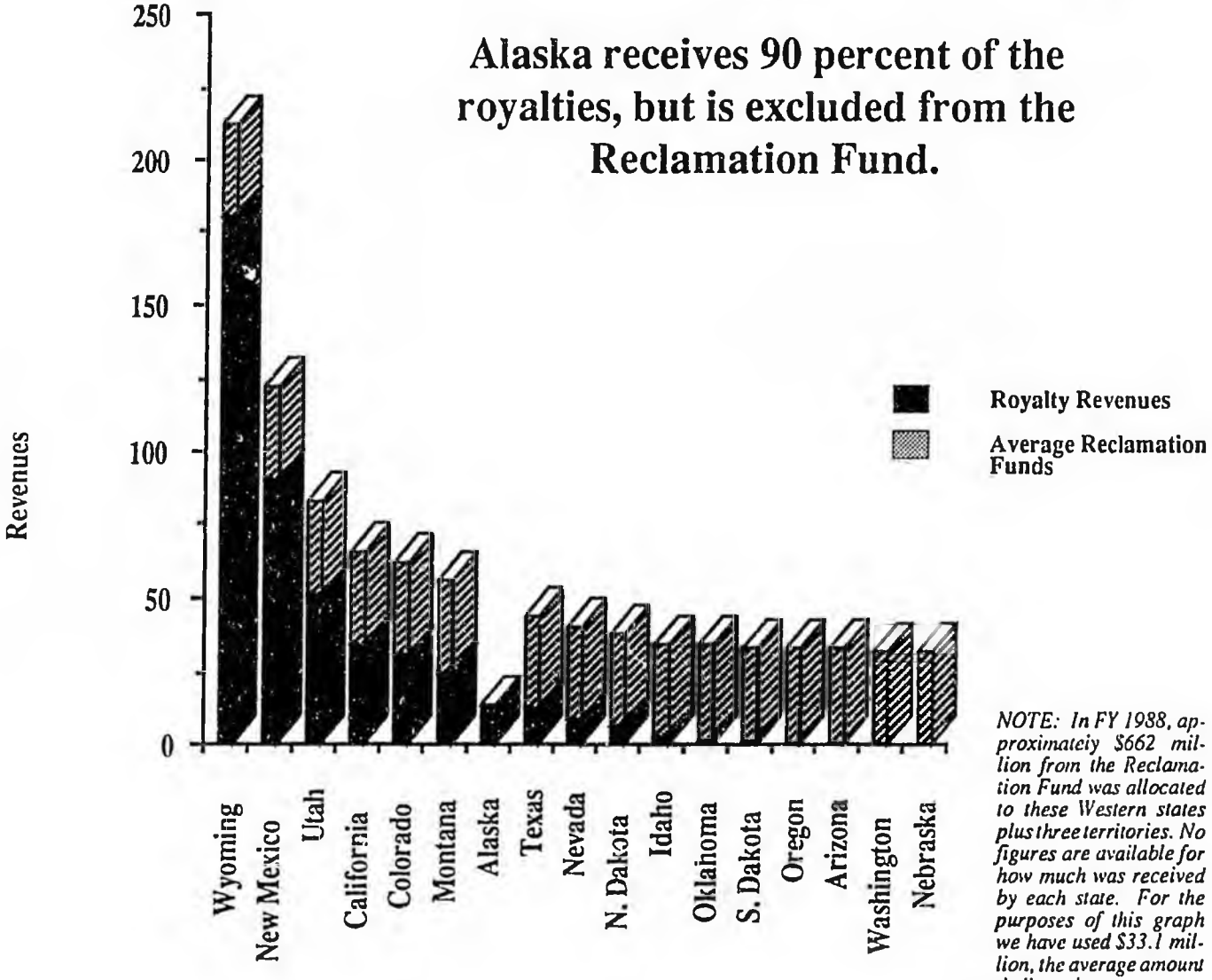
Alaskans, most of whom strongly support the opening of ANWR's Coastal Plain to oil and gas development, talked about trading a portion of that 90% to achieve the objective of opening ANWR. "Fifty percent of something is better than 90% of nothing" was the comment of many.

However, others feel that of all the ANWR issues, the 90/10 royalty split speaks to why and who we are as a state. Will we allow our present economic conditions to affect our position on 90/10? Will we, as so many other minorities in American history, allow our economic future and identity be traded away once wealth is discovered? The federal government has made us many promises, and it is based on those promises that we exist as a state, and as a people. Are we now willing, because of tough times, to forfeit our rights as a state without even allowing our people to vote on the question?

The royalty split works like this

The seventeen states shown in this illustration receive 50 percent of the royalties from oil and gas leases on federal lands within their jurisdiction. In addition, forty percent is dedicated to the Reclamation Fund which is used for water and conservation projects in these states.

Alaska receives 90 percent of the royalties, but is excluded from the Reclamation Fund.



NOTE: In FY 1988, approximateiy $662 million from the Reclamation Fund was allocated to these Western states plus three territories. No figures are available for how much was received by each state. For the purposes of this graph we have used $33.1 million, the average amount dedicated per state.

What does a change from 90% to 50% mean in revenue losses to the people of Alaska?

Typically, the federal royalty is 12 1/2% of the wellhead price which is then divided between the state and federal government. If we use the "modal" number (the most likely value to occur) there will be an estimated 2 billion barrels of recoverable oil in ANWR. The difference between 90% and 50% works out like this:

Alaska's share at 90%	**225 million barrels**
Alaska's share at 50%	**125 million barrels**
	<100 million barrels>*

If ANWR oil reserves prove to be the size of Prudhoe Bay, Alaska would lose $5.25 billion.

At $10 per barrel wellhead price, Alaska will receive $1 billion less if we receive 50% instead of 90%.

If we use the "mean" estimate of 3.23 billion barrels, as projected by the Department of Interior, 50% of the royalties would mean a loss of $1.62 billion. If the high-side estimate of 6.7 billion barrels materializes, Alaska would receive $3.35 billion less. If ANWR proves to be the size of Prudhoe Bay (10.5 billion barrels) Alaska, at a wellhead price of $10, would lose $5.25 billion. Should we, as parents of future Alaskans, allow this to slip away without a fight?

These are burdens the people of Alaska should not be asked to pay without their consent.

It could even get worse. President Reagan's federal budget for 1990 proposed that 100% of oil royalties from ANWR be retained by the federal government. The State of Alaska would receive nothing. This extreme position will probably not prevail; however, it is representative of the forces arrayed against Alaska's 90/10 royalty split as guaranteed by the Statehood Compact.

After review of opposing legal analysis of this issue, most attorneys conclude that the State Attorney General has properly reviewed the Statehood Act, its intent and the historical context within which Alaska was admitted to the Union. This provision was a national compromise as well as a compromise by the people of Alaska—one agreed to after significant debate and a vote by the people of the new state

The violation of Alaska's rights as a state and the loss of billions of dollars in revenue are burdens the people of Alaska should not be asked to pay without their consent.

If an individual were to take from a person in economic distress the rights and revenues appropriated by the federal govern-

* Source: Ed Phillips, Royalty Specialist, Alaska Department of Natural Resources.

If Congress reduces Alaska'
royalty share to 50% in ANW
it <u>will</u> make a difference.

This graph illustrates the several estimates of the revenue which may be lost by Alaska if the 90% royalty share granted at statehood is reduced to 50%.

If 2 billion barrels of recoverable oil are found and produced -- This is the so-called modal estimate (the most likely to occur) according to the Department of the Interior.

If 3.23 billion barrels of recoverable oil are found and produced -- This is the so-called mean estimate (the average of the estimates) according to the Department of the Interior.

If 6.7 billion barrels of recoverable oil are found and produced -- This is the most optimistic prediction according to Department of Interior geologists.

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Source: Alaska Departm

ment in the present ANWR bill, clearly the courts would find it unfair, unjust, unlawful and certainly unconstitutional.

"...unfair, unjust, unlawful and certainly unconstitutional."

Alaska, as a sovereign state, should expect to be treated as no less than a person. Alaskans must demand no less.

Congress may well decide to open ANWR, and most Alaskans will continue to support such action. But Alaskans must be part of the decision and, if the Statehood Compact is altered, must be given the opportunity to ratify the terms.

Chapter 4 — The Labor Movement and ANWR

Organized labor played a pivotal role in the passage of the trans-Alaska oil pipeline legislation in 1974. The late George Meany, after a briefing on the issue, rallied his 36 international presidents to a unanimous decision to put their political muscle behind the pipeline legislation. These unions and their lobbyists delivered nearly a dozen votes in the US Senate.

Even with labor's help, oil industry lobbying, and support from the White House, the vote on the trans-Alaska pipeline legislation was a 50-50 tie.

Even then, public sentiment was hard to mobilize. With labor's help, oil industry lobbying, and support from the White House, the vote was a 50-50 tie. Vice President Spiro Agnew cast the deciding ballot, and the bill became law.

In 1986, as the ANWR issue began to surface, Alaska labor reversed its traditional pro-development stand. A group of top Alaska labor leaders chose to stay neutral and threatened to join those environmentalists who oppose the opening of ANWR in order to obtain present and future concessions from the oil industry.

This plan ran counter to several decades of Alaska labor history in which the unions stood in the forefront of efforts to assist major development projects. It resulted from a clash between labor and oil a decade earlier over the Project Labor Agreement for the oil line construction in 1974.

In June of 1987, this Commonwealth North ANWR Committee developed six ANWR consensus points (Appendix A). The Alaska AFL/CIO, added their support. These points included the phrase "encouraging Alaska hire and a fair wage." But labor refused to help lobby Congress to pass an ANWR bill. When asked, labor's response was that they wanted an agreement with the major oil producers in Alaska—ARCO and BP Exploration. Once they had that agreement, they would help.

Both labor and oil should support the encouragement of Alaska hire and a fair wage for ANWR work.

The position of the producers was that such an agreement could well be meaningless, as it would be impossible to predict who would be the successful bidders for ANWR leases. In addition, decisions on which contractors would be hired to help develop ANWR will probably be made by groups of companies working together through "unit agreements." Any commitment with labor reached at this time might make those companies liable under the anti-trust laws.

Most Alaskans have argued that until ANWR legislation passes there will be no new jobs created—union or non-union.

In any case, a series of meetings took place between the major oil company producers in Alaska and labor leadership. At first these sessions appeared to be promising. But on April 19, 1988 a letter from the Building and Construction Trades Department of the AFL-CIO in Washington, D.C. urged the Subcommittee on Fisheries and Wildlife of the House Merchant Marine Committee to vote against the ANWR bill before them.

Before supporting ANWR legislation, labor now says it wants a project labor agreement.

Alaska's labor leadership told Commonwealth North that they were surprised by the letter. At that time, they had not demanded a union-only project labor agreement, but merely a signed commitment from the major producers in Alaska for "a fair wage and a maximum amount of Alaska hire possible under law." Since then, Alaska labor has followed the lead of their national officers and called for a project labor agreement.

In summary, due to the history of oil/labor relations in Alaska and the struggle by organized labor to obtain work on the North Slope now and if ANWR were opened, Alaska labor has remained on the sidelines. National labor leadership has taken a confrontational stance. To date, the oil industry has been unable to accommodate labor demands.

A breakthrough is needed to enlist labor support.

Progress must be made in this relationship before ANWR once again surfaces on the national agenda. Key House Democrats lead the Congressional committees addressing the ANWR issue. Many of them have strong labor constituencies. With the help of organized labor, ANWR legislation will have a much better chance of becoming law.

Chapter 5 — Proposed ANWR Land Trades

Native land exchanges were authorized by both the Alaska Native Claims Settlement Act (ANCSA) of 1971 and the Alaska National Interest Lands and Conservation Act (ANILCA) of 1980. The intent of such swaps was to allow federal, state, and Native land managers to adjust boundaries, consolidate land holdings and permit better use of their properties after resources had been inventoried. But the scope and scale of such anticipated exchanges was not extensive.

Land exchanges were authorized by Congress to allow for better land use after resources had been inventoried.

Several exchanges have taken place, most notably the 1984 Kaktovik Village Corporation swap of acreage in the Gates of the Arctic National Park for properties with extremely high oil potential in the Arctic Coastal Plain south of Barter Island.

U.S. Fish and Wildlife Service spokesmen indicate that they initiated the idea of ANWR land swaps. Their goal was to obtain what they considered to be premier wildlife habitat owned by Alaska regional and village corporations inside seven Alaska refuges — the Kodiak, Kenai, Yukon Delta, Innoko, Kanuti, Nowitna, and Alaska Maritime refuges. The Department of the Interior heralded the exchanges as "a unique opportunity to acquire 896,000 acres of inholdings, representing the largest single acquisition of the National Wildlife Refuge system." Biologists feared that if these inholdings were not acquired that they may be distributed by the Native corporations to their shareholders, sold to third parties, or levied upon in satisfaction of the debts of a corporation.

The trades are seen as an opportunity for the Native corporations to parlay remote land parcels into potentially lucrative agreements with oil company partners.

In exchange for these lands, the Native corporations negotiated for oil and gas exploration and production rights to 166,000 acres of subsurface estate on the Coastal Plain of ANWR. These agreements presented an opportunity for the Native corporations to parlay remote land parcels, which otherwise might have little economic value, into potentially lucrative agreements with oil company partners. It also allowed the Native groups to retain rights to subsistence use on the lands they "swapped." Potential returns for participating corporations and their stockholders beckoned if major oil discoveries resulted from the exploration process at ANWR.

Some oil company partners in the land exchange proposals actively promoted the concept. If these tracts were owned by private entities, they argued, years of delay would be avoided in terms of government permitting and potential environmental lawsuits. Oil would be found and produced much more rapidly, therefore benefitting both the state and the nation. Also, if the exchanges were approved by Congress, these resource companies

would acquire part ownership in strategically located leases in the most promising unexplored oil and gas province in North America. And they would have avoided the uncertain and potentially more expensive competitive bid process required under the standard procedures of the Mineral Leasing Act.

The State's role

The State of Alaska owns hundreds of thousands of acres which land specialists felt could be of interest for trades with the Department of Interior, especially the National Park Service. Staff within the Alaska Department of Natural Resources made a concerted effort to participate in the land exchange process. Supporters of this initiative believed that the State of Alaska was best positioned to manage oil activities in ANWR, as it had successfully overseen the developments of Prudhoe Bay during the past 20 years. In 1986, the Sheffield administration went to the bargaining table with the Department of Interior.

When Governor Steve Cowper was elected, Commissioner of Natural Resources Judy Brady hired consultants who looked at the contracts being fashioned between Interior and the Native Corporations. The new administration concluded that the state would be legally vulnerable if they supported the trades with the Native Corporations or condoned them by staying at the table. Governor Cowper withdrew the state's negotiating team.

The Cowper administration, which opposed the Native land trades, concluded that the state would be legally vulnerable if it stayed at the negotiating table.

At this point, the Commonwealth North ANWR Committee delved into the issue and held a series of meetings with most of the participants. Six consensus points written by the Committee and approved by the Board in June of 1987, included the following statement:

> "4. Exchanges of public or privately owned inholdings in federal conservation system units for leases in ANWR should be encouraged as part of an open, competitive bidding process."

In other words, Commonwealth North's ANWR Committee opposed negotiated trades but supported allowing Native groups or the state as a landowner to be able to use "land credits" in lieu of dollars in the open, competitive bid process.

Commonwealth North's ANWR Committee opposes the trades, but supports the use of "land credits" in an open, competitive bid process.

In the fall and winter of 1987-1988, the land trade issue clouded the ANWR debate. Lobbyists supporting the trades agressively worked the halls of Congress, and the State of Alaska launched an equally strong counter campaign to defend its position.

Quietly Commonwealth North attempted to lower the rhetoric, urging that this issue be addressed only after Congress passed an act to open the Coastal Plain to oil and gas exploration and development.

In June 1988, the General Accounting Office published a highly critical report on the land trades.

In June 1988, the General Accounting Office published a highly critical report on the land trades. The GAO's conclusions were as follows:

1. About three-fourths of the Native inholdings the government would acquire would provide only limited wildlife and habitat protection benefits;
2. The negotiated price the government would pay for the inholdings is six times their appraised fair market value; and
3. Generally accepted methods for dealing with uncertainty in acquiring the oil and gas tracts — requiring competitive bidding and retaining a continuing interest (royalty) in the actual amounts of oil and gas that may be produced — were not employed.

The Interior Department charged that the GAO report was oversimplified and incorrect.

The Department of Interior disagreed with the GAO'S findings and stated that the GAO recommendation was reached by oversimplification and misunderstanding of numerous complex issues relating to the exchanges.

For example, Interior is authorized by the provisions of ANCSA and ANILCA to make land exchanges for other than equal value if the Secretary determines it is in the public interest to do so. "Fair market value was only one of several factors given consideration" in the exchange process. "Other considerations included the natural resource and public use benefits attributable to the lands, transactional savings to the United States, and past Congressional and administrative precedents."

GAO considered Interior's comments in its findings and recommendations and concluded that the Interior proposal was flawed and urged Congress to disapprove it.

The State of Alaska has maintained its opposition to the land trades proposal and has drawn similar conclusions to those of the GAO.

The time-tested public policy of open competitive bidding should be utilized in ANWR.

It is the considered opinion of this Commonwealth North Committee that the land trades, as proposed, should not be approved and that the time-tested public policy of open, competitive bidding should be utilized if leasing is authorized in ANWR.

A "killer amendment" in House Resolution 3601 creates a National Wildlife Refuge out of the 23.5 million acre National Petroleum Reserve Alaska.

In the spring of 1988, the House Committee on Merchant Marine and Fisheries passed House Resolution 3601. The bill was entitled the National Fish and Wildlife Enhancement Act of 1988. Eighty-nine pages in length, this bill permits oil and gas leasing in ANWR with a multitude of restrictions and conditions. Section 213 of the Resolution creates a National Wildlife Refuge out of the 23.5 million acre National Petroleum Reserve Alaska. Hardly debated either in Alaska or Washington, D.C., the amendment has far-reaching implications and is seen by this Commonwealth North Committee as a "killer amendment.".

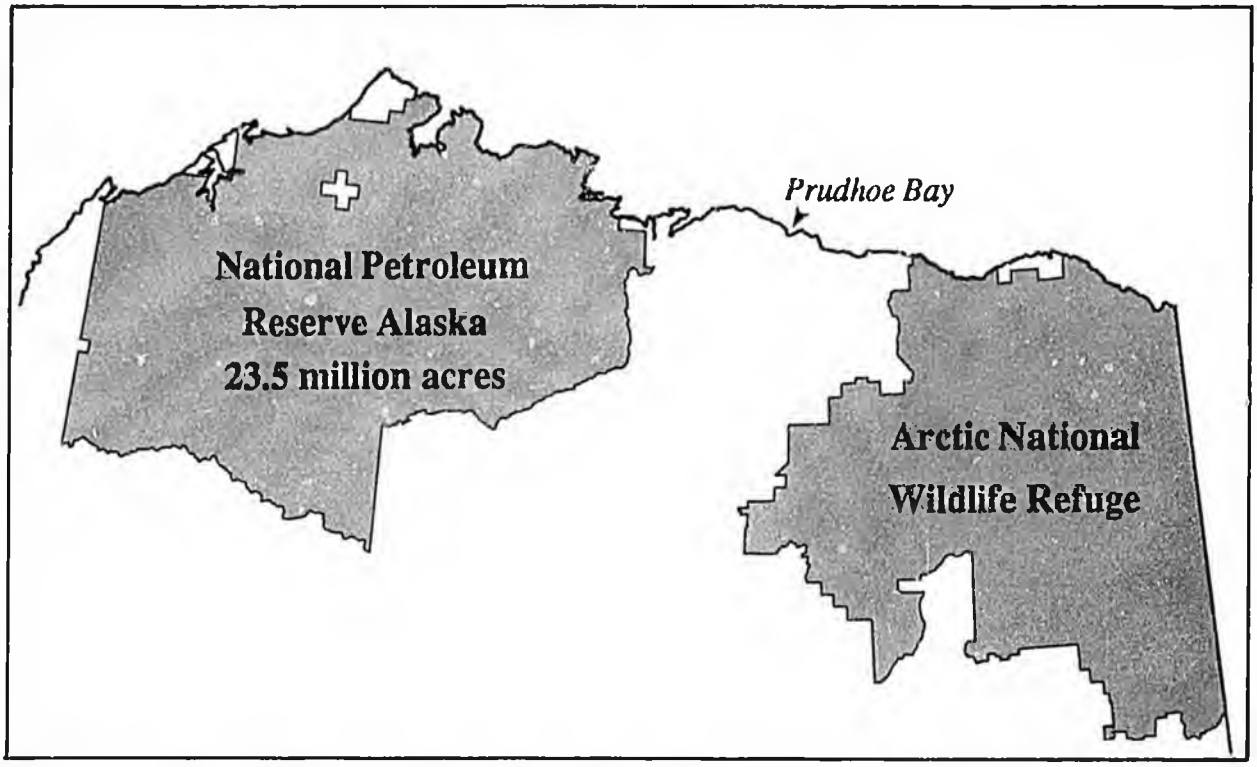
National Petroleum Reserve of Alaska (NPRA) is a huge, 37,000 square mile, treeless Arctic desert, permanently frozen to a depth of over 1,000 feet. It contains the largest Eskimo city in the world. Captain James Cook reached Icy Cape in 1778 and various explorers, especially those who in 1848-53 were seaching for Sir John Franklin, explored the coastal areas. Still it was not until 1917 that Sandy Smith "discovered" oil seeps that the Eskimos had known about for centuries. Soon after, a few oil claims were staked, but President Harding gleefully throttled that activity by making the whole area a National Petroleum Reserve in 1923.

For four years beginning in 1923, the U.S. Geological Survey sent its excellent explorers/geologists on long, tough, mosquito-plagued trips across the mountains and over the unending tundra to the Arctic Ocean. Finally, in the war year of 1944, the Navy began drilling and geophysical work which terminated in 1953. They found one medium-sized oil field at Umiat, a gas field at Barrow and lots of natural gas in the Gubik Field. Further work directed by the U.S. Geological Survey and others in the late 1970's and early 1980's failed to find oil in sufficient quantity to warrant development.

All past drilling in NPRA amounts to only one exploratory well for every 360,000 acres.

While it might seem that Sandy Smith's "discovery" had flopped, there remains the astonishing fact that the 37,000 square mile reserve, with numerous oil shows other than Sandy's, has had only 65 exploratory wells poked in it (not counting some development wells at Umiat and Barrow); and some of the 65 wells did not reach basement. All past drilling amounts to one exploratory well for 360,000 acres; some counties in Texas have had 100 wells drilled before oil was found in great quantity.

By comparision with other states, the NPRA oil prospecting record is not too bad. The Umiat oil field is estimated to contain 70



The National Petroleum Reserve Alaska contains vast resource potential

1. Oil and gas – set aside by the U.S. Navy in 1923 as a petroleum reserve, millions of acres of NPRA are considered highly favorable for significant accumulations of oil and gas.
2. As much as 40% of remaining bituminous coal resources in the U.S.
3. Rare earth minerals such as yttrium and scandium, used for super-conductivity.
4. Base metals – lead, zinc and silver.
5. Various strategic minerals, such as chromium, nickel and the platinum group.

Source: Mineral Resources Division, U.S. Bureau of Land Management

million barrels of recoverable oil (probably 120 million if a water drive enhanced recovery program should be used). That would make a nice oil field if located near transportation. The Gubik gas field, with only two test holes, may contain as much as 295 billion cubic feet of natural gas.

One well-qualified expert estimated that there are 900 billion tons of recoverable coal in NPRA — the BTU equivalent of 250 Prudhoe Bays.

NPRA contains one of the world's largest coal reserves; about half of the 37,000 square miles contains coal, varying from sub-bituminous to bituminous in grade. Estimates of possible reserves range from hundreds of billions of tons to trillions. One well-qualified expert estimated that there are 900 billion tons of recoverable coal, equivalent in heat units to 3,500 billion barrels of crude oil — 250 times the recoverable crude oil in the largest oil field in North America, Prudhoe Bay.

Searching for a continuation of the very large and rich lead and zinc deposits of the Wulik River area, the southern border of NPRA was examined by the U.S. Bureau of Mines and the U.S. Geological Survey during the short summer seasons of 1977 and 1978. Although severely hampered by bad weather and the usual logistical problems (one participant estimates that there were only 45 truly effective field days in the two year period) lead, zinc and copper anomalies were shown by geochemistry to extend intermittently across the entire 150 mile long southern boundary. Along the southeastern portion, for a distance of nearly 60 miles, the anomalies were more frequent and four distinct outcrops of high grade lead, zinc, and silver ore were discovered. At one of the discoveries, mineralization has been traced at least 6,500 feet. Ore grades up to 44% lead, up to 49% zinc, and up to 27 ounces per ton of silver have been reported from the outcrops.

Red Dog appears to be the anchor of one of the world's most important mineralized trends stretching along the 150 mile southern boundary of NPRA.

The geological anomalies and ore deposits found in the very brief reconnaissance of 1977-78 appear to be along a mineralized trend from the huge Red Dog and Lik lead, zinc and silver deposits located about 40 miles southwest of NPRA. The Red Dog Mine, recognized as the largest and richest lead, zinc and silver mine in North America, appears to be the anchor of what may be one of the most import lead, zinc and silver districts in the world.

Even if someone solemnly claims to have inherited a gift of clairvoyance from the Delphic Sibyl, can he have the effrontery to deny to future generations the right to use the probable oil, the certain coal and the obviously rich metal recoverable from a vast area that is permanently insulated from capricious development by long, black, windy winters and short, bug-filled summers?

Conclusion

To place NPRA in a Wildlife Refuge status designates this vast, rich area for a single purpose "to conserve fish and wildlife populations and habitats." It stops any further oil and gas leasing for five years and makes any future leasing persuant to the Refuge Administration Act, which is extremely restrictive and cumbersome. It places the authority for deciding on port facilities or offshore causeways in the hands of federal and state fish and wildlife agencies, and is restrictive as to transportation and utility corridors.

To make NPRA a Wildlife Refuge would designate it for a single purpose.

Chapter 7 — An Ideal ANWR Bill

Oil and Gas Development

An ideal ANWR bill should permit and encourage careful oil and gas exploration and development on the Coastal Plain of ANWR. The government should not enter the oil business by financing a government exploration program, such as the wasteful and nonproductive NPRA program.

Environmental Protection

The protections and requirements for oil development in Prudhoe Bay and Endicott are adequate for the Arctic Coastal Plain in ANWR. Most additional restrictions add cost to the delivery of energy to America and contribute little to an already excellent environmental protection process.

A "core calving area," set aside for a study period of not more than 5 to 7 years, may be required politically to quiet the concerns of Congressmen and their constituents from the Lower 48. Biologically, such a study is not necessary because of the laboratory results of 20 years of operating on the North Slope some 100 miles to the west. There, the Central Arctic caribou herd has flourished and multiplied three-fold since oil activities began.

Royalties

The State of Alaska should stand its ground regarding the 90% royalty pledged, promised and voted upon by the Alaskan people at the time of statehood in 1958. Any reductions of that royalty should only be agreed upon by consent of the governed through a plebiscite and in exchange for other benefits.

Labor in ANWR

Labor and the oil industry must find a means for accommodating each others' needs in developing ANWR. The support of both is essential to speedy passage of favorable ANWR legislation. The ANWR bill itself should not be encumbered with language (such as the Manton Amendment) which requires union hire.

Land Trades

The ANWR bill should not include land trades between private entities and the federal government. Such proposals should be addressed later, separately, and on their own merit.

No "Christmas Tree" Legislation

The National Petroleum Reserve Alaska, the Tongass National Forest, and additional National Park Service wilderness areas should all be addressed separately by Congress. In no case, should the ANWR bill be used as "Christmas Tree Legislation" as a pay-off to various interest groups.

Appendix A

TOWARD A CONSENSUS ON THE ARCTIC NATIONAL WILDLIFE REFUGE

April 24, 1987

Commonwealth North's Board and ANWR Committee call on the Governor, the Congressional Delegation, and the citizens of the State of Alaska to encourage the immediate development of the oil and gas resources of the Coastal Plain of ANWR.

1. *It is essential to the mutual interests of Alaskans and the nation to encourage the immediate development of the oil and gas resources of the Coastal Plain of ANWR.*

   - Nationally, oil and natural gas imports have risen 37% from last year, contributing to the nation's $60 billion trade deficit and making the U.S. increasingly vulnerable to foreign oil suppliers.

   - ANWR is universally recognized as the most promising onshore oil and gas frontier in North America. At least 26 identified geological structures in ANWR have oil and gas potential which may rival Prudhoe Bay's giant field.

   - The Secretary of the Interior, after a 5 year study by the U.S. Fish & Wildlife Service, has recommended that Congress approve an oil and gas leasing program in ANWR's 1002(h) area (roughly 8% of the 19 million acre Refuge).

2. *The Arctic Coastal Plain must be developed, as Prudhoe Bay has been, with utmost care for environmental and wildlife values.*

   - Alaskans are rightfully proud of the record established on the North Slope whereby resource development and the care and protection of wildlife, including the Central Arctic caribou herd, have gone hand in hand.

3. *Time is of the essence. Congress must be encouraged to act.*

   - Once Congress gives the "go-ahead" and if oil is discovered, it will take approximately 10 years to produce ANWR oil.

   - Already one out of every four barrels of oil produced in the U. S. comes from Alaska's North Slope. But North Slope production is expected to drop from 2 million barrels per day to 500,000 barrels per day by the year 2000. In other

words, if ANWR is not developed by 2000, Alaska's oil production may decrease to 1/4 of the current output.

4. *Exchanges of public or privately owned inholdings in federal conservation system units for leases in ANWR should be encouraged as part of an open, competitive bidding process.*

5. *The state should encourage a high level of Alaska hire and a fair wage during ANWR exploration and development.*

6. *The State of Alaska, with the Governor taking the lead, must mount a major educational campaign to inform Congress and the American people about ANWR.*

   - The citizens of the State should be encouraged to participate in this campaign by rallying support among their friends and contacts across the nation.

Appendix B

Who ever heard of a nation fighting for dependence?

Usually the opposite holds true. Yet today, the attention of the entire nation is focused on just such an issue. And the battle lines are drawn.

Alaska's Arctic National Wildlife Refuge (ANWR) stands at the center of this controversy. Should oil development be permitted on the Coastal Plain which constitutes only 8% of ANWR and is considered to be the most promising onshore oil and gas province in North America?

Unfortunately, there are single interest groups which are attempting to postpone this decision. But delay will only increase our alarming dependence on foreign oil.

America needs Alaskan oil. In just two years, Prudhoe Bay production will begin to decline. By the year 2000 if there are not substantial new oil discoveries made on the North Slope, the trans-Alaska pipeline will run at one-fourth the throughput it is today.

For these reasons, as Alaskans, as Americans, we urge the citizens of this country to address this issue with a united voice . . . for everyone's sake.

WE ALL AGREE that in the national interest it is vitally important that Congress encourages oil exploration and production on ANWR's Coastal Plain.

STEVE COWPER
Governor of Alaska

JAN FAIRS
Alaska State Senate President

BEN GRUSSENDORF
Speaker of the Alaska House of Representatives

TED STEVENS
U.S. Senator, Alaska

JACK COGHILL
Chairman, Alaska Senate Natural Resources Committee

SAM COTTEN
Co-Chairman, Alaska House Natural Resources Committee

FRANK MURKOWSKI
U.S. Senator, Alaska

GEORGE N. AHMAOGAK
Mayor, North Slope Borough

DON YOUNG
U.S. Congressman, Alaska

COMMONWEALTH NORTH

JACOB ADAMS
President, North Slope Borough Assembly

Presented in the Public Interest by Commonwealth North
619 West Third Avenue, Anchorage, Alaska 99501

The above Commonwealth North statement was run as an advertisement in newspapers throughout Alaska in August 1987.

Commonwealth North is a non-profit corporation, organized and existing under the laws of the State of Alaska. Non-partisan in nature, its purpose is to inject enlightened vitality into the world of commerce and public policy. As well as providing a forum for national and international speakers, working committees study critical issues facing the state and the nation and prepare well-researched proposals, such as this one.

A proposal by

935 West Third Avenue
Anchorage, Alaska 99501
(907) 276-1414 • FAX (907) 276-6350

Additional copies available for $7.50

ADDENDUM

On the eve of publication of this report, a tragic oil spill took place outside the Valdez harbor. The authors, along with all Alaskans and millions around the world, were shocked and saddened by this failure of a transportation system which had previously proven to be nearly flawless. The reasons for the disaster and ways to prevent a reoccurrence are not yet clear. They must and will be thoroughly examined.

At the same time, the authors of this paper stand by the conclusions and recommendations written herein. They believe that these findings will contribute to the statewide understanding and the national debate over the highest and best use of the enormous energy resources which may exist on the coastal plain in the Arctic National Wildlife Refuge.

The ELF

A Policy Perspective

April 1988

Division of Policy
Office of the Governor

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Preface

Since statehood, oil taxes have been a continuing and difficult policy issue for Alaskans. The current debate centers on the state severance tax and the economic limit factor or "ELF." Put simply, the ELF is a tax reduction formula meant to encourage marginal oil field development. The Governor proposed ELF legislation last year, and a bill to make a change in the ELF formula passed the House.[1] The oil companies, with one notable exception, oppose the change, and the bill has now stalled in the state Senate, where the leaders have said they oppose allowing the bill to come to a vote.

In the Alaska legislature oil tax issues have traditionally received intense scrutiny. Each side has had the opportunity to challenge the assertions of the other, bring its experts forward, and present its case. This process has not been perfect, but the legislators and the public have been able to get the facts to make informed decisions. Nothing will substitute for the give and take of a public hearing, but in the face of the Senate's refusal to allow this major policy issue the open debate it deserves, the state administration has a responsibility to make its perspective known.

We believe passage of the new ELF will help stabilize the Alaska economy at a time when it needs the reassurance of stable state spending. More stable revenues from the new ELF will help guarantee that local governments receive the money they need for roads, public safety and other services, and explains why the Alaska Conference of Mayors, among others, supports the ELF bill. Most importantly, passage of the new ELF

[1] House Finance Committee Substitute for House Bill 164, amended [CSHB 164 (Fin.) am].

will provide a more reliable incentive for marginal field development — the ELF's original purpose — by lowering tax rates on Alaska's smaller fields, such as Milne Point, Endicott, and Lisburne.

This paper attempts to fully discuss the reasons behind our perspective. We have tried to include all the relevant facts. We also have tried to avoid unnecessary complication. If others have additional information and perspectives, we welcome hearing from them.

Mary Halloran
Director, Division of Policy
Office of the Governor

Executive Summary

- The immediate revenue loss from the current ELF is about 8 percent of Alaska's oil revenues, or about $150 million this year. This percentage loss will increase over the next six years to about 14 percent and will erode Alaska's fiscal strength.

- The 1987 application of the ELF to Prudhoe Bay was adopted within 72 hours in the closing days of the 1981 legislative session. Legislators and the Governor were assured the tax changes were revenue neutral — incorrectly as it turned out. In fact, the revenue loss has been over $1 billion from FY82-FY87.

- Neither the Railbelt Energy Fund nor the Permanent Fund earnings reserve provides a long-term response to the on-going loss of 8 percent to 14 percent of Alaska's oil revenues and the erosion of Alaska's fiscal strength. The new ELF does.

- Prudhoe Bay and Kuparuk are extraordinarily profitable oil fields. Industry journals indicate oil companies make $6.2 million per day in profits from North Slope operations. Currently, the oil industry is taking $8 Outside for every $2 it reinvests in Alaska. Without their Alaska holdings, neither ARCO nor Standard would be as strongly positioned against their industry competitors as they are today.

- The oil industry has one of the poorest resident hire records in the state, with major drilling, exploration and service companies employing about 28 percent non-residents.

- The written record of the 1981 legislative deliberations on oil taxes provides no evidence of any legal, moral, or political commitment by state officials regarding any limit on the state's appropriate share of future oil income. In fact, the legislature and the governor explicitly recognized that today's legislature would have to grapple with the revenue problems caused by the reimposition of the ELF.

- At Prudhoe Bay, at a profit of $3 per barrel, wells that average over 2,000 barrels per day — more than 100 times greater than the national average of 14 barrels per day — are receiving the benefit of an ELF reduction designed for fields whose economics are marginal.

- The new ELF's consideration of total field productivity, as well as per-well productivity, provides a better incentive for marginal field development than the current ELF and better reflects field profitability.

- By adding total field productivity to the ELF calculation, most Alaska fields will receive a larger tax break under the new ELF than under the current ELF. Only the two giant fields, Prudhoe Bay and Kuparuk, will not receive increased tax breaks. Fields with Alaska corporation ownership, such as Endicott, will benefit more under the new ELF than the current ELF.

- The current ELF provides a substantial state subsidy to oil company drilling operations in the nation's two largest and very profitable oil fields by lowering the effective tax rate on an entire field every time a below-average producing additional well is brought on line.

Introduction

The major issue in the current debate over the ELF (economic limit factor) is whether this tax reduction to the oil industry makes sense for Alaska at this time. Among the different perspectives against which Alaskans judge the issue are the ELF's effects on the rate of oil development and jobs, and its impact on state revenue, budget stability and the economy. The purpose of this paper is to fill in as much as possible of the factual background. The following issues are therefore addressed in detail:

(1) ELF AND OIL DEVELOPMENT: Does the current ELF tax subsidy work to increase marginal field development? Are Prudhoe Bay and Kuparuk marginal fields? Do ARCO, Standard and Exxon, the major North Slope producers, need a substantial tax break now to continue production from Prudhoe Bay and Kuparuk? How does Alaska's tax structure compare with that of other states?

(2) ELF AND ALASKA'S ECONOMY: How much does the current ELF contribute to industry drilling activity? What will be the effect of the new ELF on drilling activity? Are oil company development dollars spent in Alaska or Outside? How many jobs does ELF create? Who gets those jobs?

(3) ELF AND ALASKA'S REVENUES: What is the difference in revenues between the current ELF and the new ELF? How does ELF affect revenue stability? What is the long-term impact of ELF on the state's fiscal strength? What roles do revenue stability and a balanced budget play in creating a stable Alaska economy?

(4) ELF AND THE PAST: What happened in 1981? Why was the ELF suspended for Prudhoe Bay? What were the commitments?

Background

The roots of the current tax debate go back to the early days of North Slope oil production. In 1979 several major oil companies sued the state, arguing that the separate accounting form of corporate income tax adopted by Alaska in 1978 was unconstitutional. The state won that lawsuit in 1986, but in 1981, in an attempt to limit the fiscal effects of possibly losing the case, the legislature changed the method for assessing oil and gas corporate income tax from separate accounting to modified apportionment. [2] That legislation also dealt with the ELF.

The 1981 tax package gave Alaska's oil producers a big reduction in their corporate income taxes, but legislators were assured by then-Revenue

[2] To tax corporate income, separate accounting focuses on the income a corporation actually produces in the taxing jurisdiction. In contrast, the apportionment formula looks at all the income produced worldwide by the corporation and attempts to attribute a portion of that income to the taxing jurisdiction. Alaska now uses a modified version of the standard apportionment method in assessing corporate tax liability.

Commissioner Tom Williams — incorrectly as it turned out — that most of the state revenue lost from the income tax would be offset by gains from a severance tax increase adopted at the same time. The bill also suspended the applicability of the ELF to Prudhoe Bay "for the first ten years following the commencement of commercial production."

The tenth anniversary came in June of 1987, triggering reinstatement of the ELF to Prudhoe Bay. Since the ELF is a formula that reduces severance tax rates, it gave the oil companies a tax cut in addition to the net tax reduction they won in 1981. The 1987 cut was substantial — worth over $15,000 per hour to the Prudhoe Bay producers or about 8% of Alaska's revenues from oil operations.

The ELF Formula: Well Productivity & Field Productivity

The ELF bill, CSHB 164 (Fin) am , substitutes a new formula for calculating the "economic limit" — the point at which production is no longer profitable. The new formula will reduce the tax reduction provided to Prudhoe Bay and Kuparuk, and increase the tax reduction afforded to smaller fields, such as Endicott, Lisburne or Milne Point.

The ELF is a number between one and zero that is multiplied by the nominal tax rate, producing the effective tax rate. The nominal severance tax rate at Prudhoe Bay is 15 percent. With the average FY 88 Prudhoe Bay ELF at .82, the field's effective tax rate is 12.3 percent (.15 X .82 = .123).

The current ELF is determined by *per-well productivity* in the field, measured by the number of barrels produced by an average well in an

average da If well productivity is high, the ELF is relatively close to 1 (.9 for example), and the field gets a small tax reduction. Fields with low per-well productivity have a smaller ELF (.5 for example), and get a larger tax break. Most fields in Cook Inlet are currently paying no severance tax because their very low per-well production gives them ELF's of zero. (Zero times the nominal tax rate gives an effective tax rate of 0.0 percent.) In Cook Inlet, the current ELF works properly, encouraging production of marginal fields.

But the super-giant Prudhoe Bay field[3] is a different story. At Prudhoe Bay, wells that average over 2,000 barrels per day — more than 14 times greater than the Texas average and more than 100 times greater than the national average — are receiving the benefit of an ELF reduction designed for fields whose economics are marginal.

This inappropriate ELF break results f om the fact that the current ELF takes account only of productivity *per well* and not overall *field* productivity. By giving a profitable field a larger tax break than a marginal field, the current ELF distorts the purpose of this tax subsidy.

Consider, for example, the case of Milne Point, a small field near Prudhoe Bay. Soon after the Milne Point field opened in late 1985, revenue officials, state economists and the management team at Conoco, the oil company operating the Milne Point field, discovered that per-well productivity, if used by itself, can be an inadequate measure of a field's ability to pay severance tax.

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[3] Production from Prudhoe Bay, the largest field in the United States, is five times that of the nation's second largest field (Kuparuk). Industry publications consistently refer to Prudhoe Bay as "super-giant."

The average well in the Milne Point field initially produced 950 barrels per day, giving it an ELF very nearly the same as the Kuparuk field, where the average well produced 1,000 barrels per day. Total Kuparuk production was then 250,000 barrels per day, while Milne Point produced less than one-tenth of that amount.

But due to its smaller size, operators at Milne Point had far fewer barrels of production over which to spread operating costs than the Kuparuk field. Although the two fields had almost identical per-well productivity, the smaller Milne Point field was less profitable, and in January 1987 the owners elected to shut down production. This experience illustrates the deficiency of an ELF formula based solely on per-well productivity.[4]

The new formula incorporated in the ELF bill will correct this perverse and unintended effect *by adding total field productivity to the ELF calculation.* Fields producing less than 120,000 barrels per day, such as Milne Point and Endicott, will have a lower ELF (bigger tax break) than under current law, while fields producing more than that amount will have a higher ELF (smaller tax break). This change will affect estimated FY 89 severance tax rates as follows:

[4] Under provisions of the current severance tax law, Milne Point producers requested and received additional tax reductions after showing that the field would be uneconomic to operate without the reductions. The administrative uncertainties of this avenue would be eliminated for smaller fields by the automatic reduction provided by the new ELF. Large fields facing similar problems could still apply for and receive the special "hardship" reductions.

EFFECTIVE FY 89 SEVERANCE RATES

	Existing Law	New ELF	*Percent Change*
Prudhoe Bay	11.9 %	14.8 %	*23 %*
Kuparuk River	6.9 %	11.3 %	*65 %*
Endicott	12.3 %	8.9 %	*-27 %*
Lisburne	6.8 %	3.6 %	*-47 %*
Cook Inlet Fields	0.0 %	0.0 %	*0 %*

That this approach benefits producers in smaller fields is reflected in the March, 1987 testimony of Conoco supporting the new ELF: "This legislation is a positive first step in encouraging the development of marginal fields in Alaska."[5]

ELF Subsidy Effect

In the summer of 1987 oil producers increased the rate at which they were drilling additional wells at Prudhoe Bay and Kuparuk. Since total North Slope production is limited by pipeline capacity to just over 2 million barrels per day, more producing wells means that average production per well is being reduced. Lower per-well production, in turn, means a bigger tax break for producers under the current ELF.

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[5] Tom Painter, Conoco Anchorage Division Manager, Transcript of Joint House Finance and House Resources Committees Hearing on House Bill 164, March 19, 1987, pp. 49-54.

Because the drilling increase started about the same time as ELF's application to Prudhoe Bay, state officials investigated the possibility of a cause-and-effect relationship between the two. The ELF's role could not be precisely determined. At the same time, because of the current ELF's sensitivity to per-well productivity changes, the investigation found that the current ELF provides a substantial — and unintended — state subsidy to oil company drilling operations in the nation's two largest and very profitable oil fields.

An example of how this subsidy works was provided by ARCO official James Weeks, during 1987 testimony before the House Finance Committee. [6] Weeks' example showed how a new Kuparuk well, so long as it produced below the Kuparuk per-well average, would result in a lower severance tax payment on the now-higher total Kuparuk production than the severance tax would have been on the lower total Kuparuk production without the well. In Weeks' example, the result was an overall tax savings or subsidy to the producer of $37,846 yearly from drilling that single additional well.

Weeks' example showed that the per-well emphasis of the current ELF formula will cause the effective tax rate on an entire field to drop when a below-average producing well is brought on line. Despite the increase in total production, the state will receive less tax revenue than if the well and its production had never occurred. This would be a perverse effect even in a marginal field.

Because this subsidy takes the form of a tax reduction rather than a payment from the state's treasury, the subsidy is restricted to fields paying

[6] A copy of the ARCO handout and the state's analysis of it are in Appendix D.

severance tax. In short, the subsidy is not available to fields like Cook Inlet, where no severance tax is currently paid.

While Weeks' example was restricted to one hypothetical new well at Kuparuk, and may or may not reflect what is currently happening at Kuparuk or Prudhoe Bay, recent econometric modeling studies by the Department of Revenue estimate the Prudhoe Bay drilling subsidy in the range of $19 million in FY 88, and about $40 million in FY 89. The model indicates that a tax break that would have totalled about $240 million during FY88-89 has been increased to approximately $300 million by the additional drilling.

Not only is this subsidy going to be costly to Alaska, it is an extraordinarily inefficient way to create jobs or additional oil production.[7] The overall effect of this subsidy may be that, by accelerating drilling that would have occurred later anyway, it robs jobs and economic stability from the future for the sake of higher production and profits in the short term.

ELF and Jobs

Alaskans are concerned about the effects a change in the ELF may have on jobs. Oil industry proponents have said that the recent increase in drilling has created 2,400 new jobs — 800 drilling jobs and 1,600 additional jobs. They implied that those jobs would be lost if the proposed new ELF is adopted.

[7] A March 1988 analysis by the Dept. of Revenue implies that each barrel gained through the subsidy through the year 2000 costs the state $175 in foregone revenue.

The figure of 2,400 new jobs (or even 800) bears no resemblance to the reality reflected in Department of Labor employment figures taken from employer records. Total oil and gas employment on the North Slope during the fourth quarter of 1987 was 3,994 jobs, down by 122 jobs from a year earlier. Drilling employment at the end of 1987 was actually about 50 jobs less than at the end of 1986. Some modest employment increase may occur this spring, but nothing on the scale of 800 new jobs is conceivable, given that 1987 year-end North Slope drilling employment was only around 500 with 12 rigs operating.[8] The Department of Natural Resources estimates the rig count will climb to 14 on the North Slope this spring. The resulting rise in employment might be 80 to 100. Each rig employs an estimated 40 to 50 workers, depending on the type of drilling.

In total, the oil industry generates about 8,500 jobs in Alaska, about 4 percent of Alaska's work force — and only about 6 percent of the entire private sector work force. Unfortunately, many of those employed by the oil industry are not Alaska residents.

The drilling companies now operating on the North Slope employ about 28 percent non-Alaskans. The hiring record of the major drilling firms ranges from 57 percent non-residents to 15.4 percent non-residents. The hiring of non-residents by other oil industry segments (exploration and services) also runs about 28 percent , with the exception of the production/ management sector, which has trimmed its non-Alaskan hiring to about 11 percent.[9] These statistics make for one of the poorest resident hire

[8] Statewide oil industry employment, however, was up by about 200 jobs over this period. For more detail on recent employment trends, see Alaska Economic Trends, Alaska Department of Labor, October 1987.

[9] The Department of Labor developed the statistics by cross-checking employment records with Permanent Fund dividend records.

records in the state, according to the Department of Labor.

Industry-wide, these non-Alaskans have total earnings of about $80 million, which is the highest amount of wages paid by any industry to non-residents. Much of this non-resident income, of course, does not circulate in or benefit the Alaska economy.

As oil fields mature, labor required to produce a given amount of oil tends to increase. Over the long run, oil and gas employment is likely to increase in Alaska due to these technical factors, regardless of the state's action on the ELF bill. A huge tax increase might discourage additional field development, but economic studies by the state and others indicate that the economic effects of the ELF change will be marginal.[10] Also, correcting the misapplication of the current ELF to Prudhoe Bay and Kuparuk, while improving incentives for smaller fields, is not likely to adversely affect future field developments. From an Alaskan perspective, given the record of the oil industry to date, a real concern will continue to be whether the jobs generated by additional oil development will be filled by residents or non-residents.

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[10] "[T]he economic limit factor in Alaska's severance tax...has limited ability and high revenue cost for conserving oil and gas from producing fields," according to University of Alaska researchers led by Mathew Berman in Alaska Petroleum Revenues: The Influence of Federal Policy, Institute of Social and Economic Research, October 1984, pp. xxvii. See also, "Severance Tax Impact Often Misinterpreted," by John Lohrenz, in Oil and Gas Journal, June 18, 1984, pp. 133-137; "Analysis of ELF Alternatives," by Charles Logsdon, Alaska Dept. of Revenue, October 14, 1986; and "A Model to Assess Economic Feasibility and Optimum Production Volume for North Slope Fields," by R. Marks and J. W. Moore (both with the Alaska Dept. of Revenue) in Journal of Petroleum Technology, August 1987, pp. 943-54.

Profitability

Does the oil industry in Alaska need a tax break now to continue production at Prudhoe Bay and Kuparuk? This question is at the heart of the current oil tax discussions.

Companies with major oil interests in Alaska are all publicly traded on the stock market. Alaska industry operations have attracted the interest of numerous trade publications, investment advisory services, and occasionally academic and government researchers. All the studies indicate that Prudhoe Bay and Kuparuk are extraordinarily profitable oil fields.[11]

According to a recent study, published February 1, 1988, in *Petroleum Intelligence Weekly (PIW),* a respected trade journal, oil companies are currently making after-tax profits of $6.2 million per day from North Slope operations. State and local revenue from North Slope oil, by comparison, is estimated by *PIW* at $4.7 million per day. (The *PIW* article and the state's analysis of the *PIW* figures are found in Appendix B.)

Under the new ELF, oil companies' profits would continue to be larger than state revenue, though not by as big a margin. Industry profits would decline to $5.6 million daily, after all expenses, taxes and royalties are paid. As Figure 1 shows, the ELF will have only a small impact on the relative shares of revenue going to the state and the producers.

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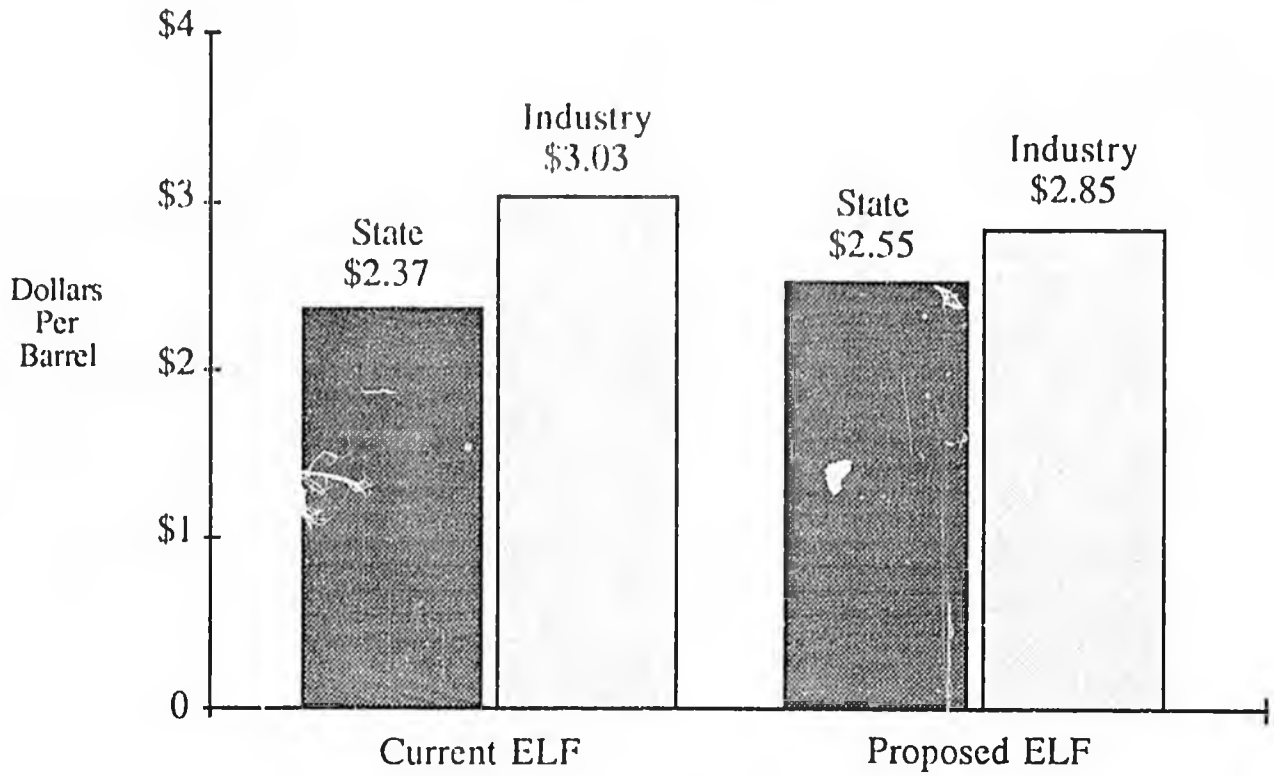
[11] In addition to the *PIW* analysis described below, the following studies have been released in 1988: "Alaska's Oil Promise Remains Strong," in International Petroleum Finance, March 18, 1988, p. 8; "Alaskan Resource Wealth -- The Inestimable Bounty" in Atlantic Richfield Company -- Restructured and Resourceful, Part II, by Salomon Brothers (Bernard Picchi, author), March 31, 1988, p. 3-4; "$30 a Barrel Profits in an $18 World," in Forbes, March 21, 1988, pp. 110-114; and "Income and Investment Flows From Alaska Oil and Gas Producing Activities," by Edward Deakin, in Joint Special Committee on Tax Policy, Final Report, Alaska State Legislature, January 1988.

Figure 1

State and Industry Shares

(Dollars Per Barrel)



Shares under current ELF are from *Petroleum Intelligence Weekly* Feb. 1, 1988; shares under the proposed ELF are by the Division of Policy, April 11, 1987.

Data on the cash flowing to and from North Slope operations suggest that since 1978 in Alaska, only a fraction of the funds generated by North Slope oil have been reinvested in Alaska. According to the *PIW* figures, the companies' current cash flow (profits and depreciation) from the North Slope comes to $10.6 million per day.[12] The Division of Policy estimates that the rate of oil industry reinvestment in Alaska is $1.9 million per day. Thus, as shown in Figure 2, the oil industry today is taking $8 Outside for every $2 it reinvests in Alaska.

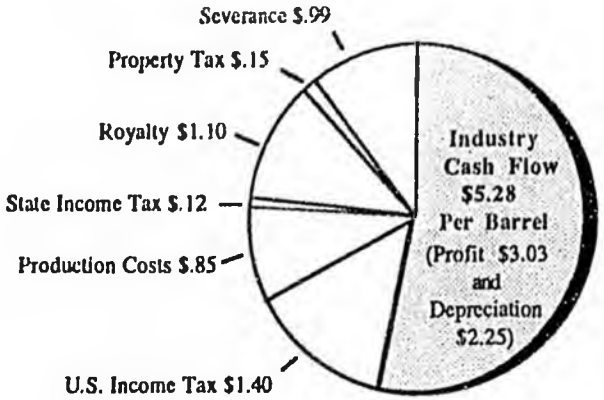
This "takeout" from Alaska's North Slope production has made the major producers in Alaska uniquely successful companies. A March 21,

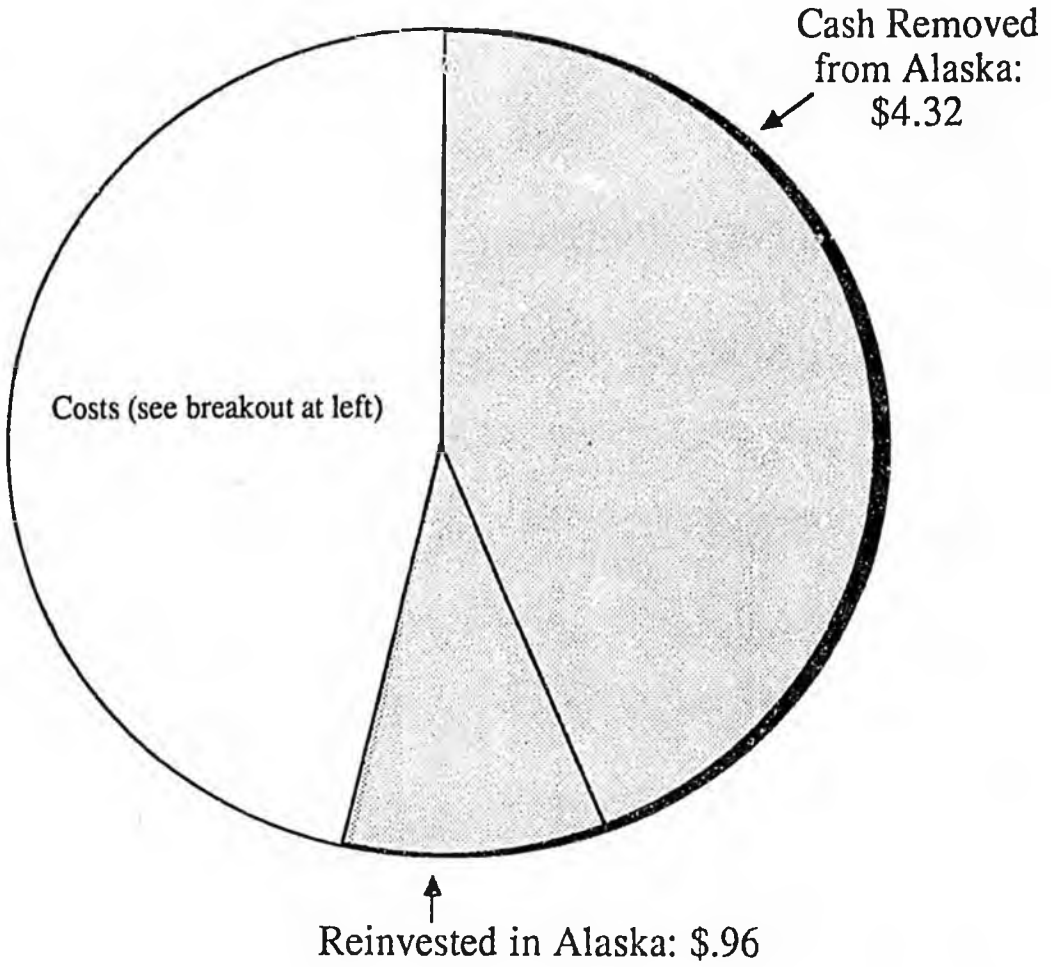
[12] The *PIW* figures do not include depreciation on the pipeline, so the cash flow to producers from North Slope operations is understated.

Figure 2

The Economics of North Slope Oil

(Dollars Per Barrel)





Source: Division of Policy, based on *Petroleum Intelligence Weekly* February 1, 1988.

Office of the Governor
Division of Policy
4/12/88

1988 *Forbes* article examined ARCO's phenomenal success: "...a return on equity of 23 percent, just about the best in the industry and roughly twice the industry average." Astute corporate management, company restructuring, and its Alaska resources let ARCO " claim the highest per-barrel profit of any marketer on the West Coast." Key to ARCO's current strength, said *Forbes*, "is its commanding position in the U.S. largest oil reserve, the Alaskan North Slope, from which it derived 68 percent of its production last year." With $3 billion in cash reserves, ARCO is actively investing its Alaskan profits elsewhere.

A report by Salomon Brothers, March 31, 1988, similarly calls ARCO "the premier equity investment in the domestic oil industry." The report goes on to say, "Arco's Alaskan resource base is without parallel in the industry in terms of its size alone. Arco's net share of the original oil in place in its Alaskan oil fields, 20 billion barrels, is **equal to 75 percent of the proved oil reserves of the rest of the country."** Top ARCO management also cited its Alaska holdings as key to the company's profitability: "ARCO Alaska's low-cost producing ability provides the base for ARCO's West Coast downstream infrastructure: its integrated transportation and refining and marketing assets." [13]

Production

Oil development patterns are not easily predictable so forecasts of future production should be interpreted cautiously. Department of Revenue modeling studies nevertheless suggest that while the new ELF

[13] "Alaska Operations," Harold Heinze, President, ARCO Alaska, Inc., Oil Industry Analysts Meeting, March 31, 1987.

could initially cause lower production, any impact would be small. The probabilities are that the new ELF will decrease North Slope output by a cumulative 1 million barrels during the FY 1988-93 period — equal to about 12 hours of flow through the TAPS pipeline. The cumulative production loss through 2005 is estimated at about 21 million barrels, or about 10 days of North Slope production. Losses taper off in later years but become gains sometime after 2020, when the new ELF increases incentives for production in the later stages of oil field life.

The ELF is a minor factor in industry decisions to pursue Prudhoe Bay development. What matters most is oil prices. For example, a spokesperson for ARCO, commenting on that company's plans to drill five Prudhoe Bay development wells in September, 1987, stated," resuming production drilling in Prudhoe i. ood news and strictly the result of higher oil prices."[14] A March 31, 1988, stock research report notes, "West Sak field production could start in 1992, because the field is profitable at oil prices of $15-20 per barrel."[15]

How does increased production benefit Alaska? Nearly all manufacturing and assembly of equipment used in the oil industry is done outside Alaska so economic impacts from that sector are small, according to Department of Labor economists. The ARCO newsletter of January 1, 1988, states, "Between 1980 and 1986, North Slope development accounted for approximately $10.5 billion in hard goods alone, according to ARCO Alaska, Inc., Standard Alaska Production Company and Conoco." The newsletter indicates one-eighth of that amount ($1.35 billion) was spent in

[14] Alaska Report, p. 1, 7/22/87.

[15] Atlantic Richfield Company---Restructured and Resourceful, Part II, by Salomon Brothers, March 31, 1988, p.1.

Alaska, with the remainder going Outside, with Texas and California the largest beneficiaries.[16] Employment opportunities, however limited, and revenues to the state, are the most readily discernible benefits to Alaska.

Comparing Taxes

Though the existing tax at Prudhoe Bay is 12.3 percent, the *nominal* rate at Prudhoe Bay, without the ELF, is 15 percent. But no field in Alaska pays the full tax rate. Furthermore, the severance tax rate contrasts with the low corporate income tax rate. [17]

Each state designs its severance tax structure for its particular conditions in that jurisdiction. The range of profitability among fields in Alaska is very different from any other state. In none of the other states is there an oil field even close to the size of Prudhoe Bay. But because the fields in other states are much nearer to oil markets, the wellhead price of a barrel is much lower in Alaska. Unlike other states, Alaska gains little

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[16] On Top of ANWR. ARCO Alaska, Inc., January 1, 1988.

[17] Here is how Alaska's effective severance tax rate compares to other major oil-producing states on a percentage basis:

State	Severance Tax as a Percent of Value
Alaska (Prudhoe proposed)	14.8 %
Wyoming (state & average local)	13.0 %
Louisiana	12.5 %
Alaska (Prudhoe existing)	12.3 %
Alaska (Kuparuk proposed)	11.9 %
Alaska (Kuparuk existing)	8.0 %
Oklahoma	7.0 %
Texas	4.6 %
New Mexico	3.8 %

This chart is based on average effective severance tax rates in FY 1988. Under current law the Prudhoe Bay rate will decline to 11.9 percent in FY 1989.

from the manufacturing and retail sales of most of its petroleum resources — although the producers realize additional profits from transporting, refining, and selling North Slope oil. Differences like these make simplistic comparisons regarding which state has the "highest" or "lowest" severance tax of limited use.

On a dollars-per-barrel basis, for example, Alaska's tax rate is among the lowest of all the producing states.[18] If the oil fields in these states were somehow transported to Alaska, all would find their severance taxes reduced or eliminated. The reason for this apparent paradox is that all are so much smaller than Prudhoe Bay or Kuparuk. Prudhoe Bay wells, according to Standard Alaska, are producing an average 2,300 barrels per day. The average oil well in Texas, in contrast, produces 145 barrels per day. A well producing at that rate in Alaska, like most oil wells in Cook Inlet, would pay no severance tax whatever under either the existing or proposed ELF. Similarly, virtually all the fields Outside that would pay tax under the current ELF would pay less tax under the new ELF.

18

State	Approximate Severance Tax Per Barrel
Wyoming (state & average local)	$2.02
Louisiana	$1.94
Alaska (Prudhoe proposed)	$1.26
Oklahoma	$1.08
Alaska (Prudhoe existing)	$1.05
Alaska (Kuparuk proposed)	$1.04
Texas	$0.71
Alaska (Kuparuk existing)	$0.62
Alaska (Cook Inlet)	$0.00

Estimates for other states are derived from the effective tax rates of other states at a well-head price of $15.50 (Gulf Coast).

The "Commitment"

The ELF issue in 1988 is the legacy of a 1981 tax bill that passed in an extraordinary hurry. The issue of how to respond to the North Slope oil producers' legal challenge to separate accounting was the focus of attention for much of the 1981 legislative session. However, the proposal that modified the ELF was first unveiled to a free conference committee on June 22, 1981. Two days later, it passed both houses and was on its way to the governor. There was little time to study the bill; moreover, the fiscal note prepared by then-Commissioner Williams included no projections beyond FY 1985. The confusion concerning what legislators and Governor Hammond meant when they adopted the 1981 legislation is not surprising.

A 1981 post-session analysis by the Legislative Finance Division showed that the ELF provision would cause state revenue to fall sharply in FY 1988. When Governor Hammond reluctantly signed the bill, he expressed "full confidence in the ability of the legislature to deal at that time" with any adverse revenue consequences.

Governor Hammond insisted that the oil tax changes adopted in 1981 not reduce the state's share below the 30 percent that was thought to be the rough percentage level of the state's share *at that time*. Hammond sought to insure that the tax changes would be "revenue neutral;" i.e., that the changes would leave state oil revenue largely unaffected. It is now clear that the changes adopted in that bill were far from neutral as to state revenue: between fiscal 1982-87 total tax collections were reduced by over $1 billion compared with what would have been collected had the changes not been made.

As shown in Appendix C, the 1981 record contains statements by Hammond, then-Rep. Rick Halford, Commissioner Williams and others addressing the future need to revise the 1981 scheme by 1987 or 1988. But the written record of the 1981 deliberations provides no evidence of any legal, moral, or political commitment by state officials to limit the state's appropriate share of future oil income. Additionally, company officials testified to the Legislature that the state's share should equal the industry share.

Revenue Effects

As originally introduced by the Governor in 1987, the ELF legislation would have kept the ELF from applying to Prudhoe Bay for an additional five years. The measure that passed the House and now awaits action in the Senate takes a more comprehensive approach: the new ELF applies at Prudhoe Bay, but the formula for calculating the new ELF includes consideration of field productivity in addition to well productivity. The new formula gives Prudhoe Bay a much smaller tax break now, but a larger tax break later when the giant field finally reaches its marginal years of production. Tax revenue from nearby Kuparuk, the second largest producing field in the United States, would also increase. All other producing fields would either pay no tax at all or receive a bigger tax break than they get under the current ELF.

The net effect of the new ELF, using the Department of Revenue's March, 1988 "mid-case" assumptions, would be $150 million in additional state revenue in FY 1988, and $152 million in FY 1989. To put this amount

in perspective, $150 million is about the amount of the combined annual general fund budgets of the departments of Fish and Game, Labor, Commerce, Natural Resources, Revenue and Environmental Conservation, and about one-quarter of the amount the state spends each year on elementary and secondary education. As the table below shows, the revenue gain from the new ELF depends, in part, on the level of oil prices.[19]

Average Oil Prices[20]	Incremental FY 89 Revenue From the ELF Bill, CSHB 164 (Fin) am
$11.00/B	$114 million
$12.00/B	$125 million
$13.00/B	$136 million
$14.00/B	$146 million
$15.00/B	$157 million
$16.00/B	$167 million

According to Department of Revenue projections, the dollar gain from the new formula would peak in FY 91 at $223 million, and then gradually diminish as Prudhoe Bay production declines. The yearly dollar gain from the new ELF will vary with oil prices and total oil production. Over the next six years, the percentage loss to the state's oil revenue from

[19] Other factors would also affect the fiscal effect of the proposed legislation. The table is based on the "mid-case" assumptions in the current Department of Revenue forecast.

[20] Weighted average of U.S. West Coast and Gulf Coast selling prices for Alaska North Slope crude.

the current ELF will increase from approximately 8 percent this year to nearly 14 percent in fiscal year 1993. (Complete long-run projections are contained in the ELF legislation fiscal note, in Appendix A .)

Budget Stability and the Economy

In opposing the ELF legislation, one senator argues that "the solution to Alaska's economic problems is not increasing taxes to fuel more government spending," but instead to just cut state spending.

How big a cut would be required to balance the budget? With only weeks to go in the legislative session, Alaska faces a revenue shortfall of about $150 million to $400 million, depending on the optimism of the forecaster. Theoretically, the budget could be balanced by cutting hundreds of millions of dollars from spending, but this approach is hard to take seriously in light of the vital impact of state spending on a recovering economy. In fact, the legislature has already recognized the role of state spending in the economy's health in its early passage of the "jobs" bill.

Budget cuts over the last three years have brought per capita real spending down — dramatically. The deepest recession the state has ever experienced was one consequence. Now — as that recession is ending — is not the time for extracting hundreds of millions of dollars from Alaska's economy.

With state spending now well below its 1979 level and the economy starting its recovery, Governor Cowper has proposed a maintenance level budget. The House and Senate can reduce the budget shortfall by eliminating proposed expenditures. But, close to half the budget is pass-

through entitlement programs to local governments, schools, and individuals, politically difficult areas to cut. It appears the majority of Senators and Representatives do not believe this is the time for inflicting the stress of another multi-million dollar spending cut on the Alaska economy. Although reductions and reallocations will certainly occur, deep cuts are not a realistic possibility.

So what options are left? The use of the Railbelt Energy Fund has been proposed. But many Railbelt voters rebel against "their" money being spent to solve a statewide problem, and the construction industry opposes any non-construction use of the money.

Another option is to use the cash reserves (earnings reserve account) of the Permanent Fund. Using the reserves would reduce future dividends. However, the necessary appropriation could be a "loan" with a promised but problematical payback in the future. Combined, the Railbelt Energy Fund and the Permanent Fund earnings reserves are the state's cash reserves since last year the Budget Reserve Fund was emptied to help meet last year's revenue shortfall. Without these funds as backstops, Alaska is left with no emergency monies to meet another precipitous drop in oil prices.

Leaving aside the obvious difficulties inherent in the use of either the Railbelt Energy Fund or Permanent Fund earnings to fill the budget shortfall this year, there remains the issue of revenue stability. This issue deserves very serious consideration for two reasons. First, Alaskans desire and need public services. Second, there clearly exists a now-demonstrated tie between Alaska's revenue stability and Alaska's economic stability. [21]

[21] For evidence of the relationship of state budget stability to economic activity in Alaska, see "Can State Spending Speed Alaska's Recovery," by Professor Scott Goldsmith and Lee Gorsuch, Institute of Social and Economic Research, University of Alaska, December, 1987.

Both reserve sources are only stop-gap measures, providing one or two years of fiscal relief, at most. Neither fund provides an answer to the on-going loss of more than 8 percent of Alaska's oil revenues and the erosion of Alaska's fiscal strength year after year. The new ELF does. It's a long-term solution to what will otherwise be a long-term loss.

Finally, the legislature simply could pretend that there is no problem. Led by the Senate, the legislature gambled last year that oil price increases would cover the shortfall in the budget with extra revenue. It worked then, due in part to the unexpected receipt of some monies owed the state by the federal government. [22] The legislature could roll the dice again. The risk is that the extra revenue will not materialize and that the state will be unable to pay its bills. If oil prices don't rise, current cash flow projections show that the risk could become reality as early as February or March 1989.

Division of Policy

April, 1988

[22] The funds received were $160 million which had been held in escrow by the federal government pending resolution of the Dinkum Sands boundary dispute.

Appendix A

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB164 (fin) am
PUBLISH DATE: _____

FISCAL NOTE

REQUEST:

Revision Date: April 4, 1988
Title: An Act Relating to the Oil and Gas Properties Production Tax & Effective Date
Sponsor: Rules/Governor
Requestor: _____

Agency Affected: _____
BRU: _____
Components: _____

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING						
CAPITAL						
REVENUE	150,150	152.330	203,450	222,850	213,940	207,490

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

See Attached

Prepared by: Charles L. Logsdon
Division: Oil and Gas Audit
Phone: 277-5627
Date: April 4, 1988

Approved by Commissioner: _____
Agency: Revenue
Date: 4/4/1988

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

page ____ of ____

This bill would effectively increase the severance tax rate on fields producing greater than approximately 120,000 barrels per day. At the same time, fields producing less than this amount would be taxed at a lower rate. The relative increase or decrease would depend on the relative per well productivity of the field. The estimates contained in this fiscal note are based on the Department of Revenue March 1988 mid scenario assumptions about production, wells, and oil prices.

The attached tables illustrate the revenue and tax rate impact of the bill by North Slope oil field. The sensitivity of the tax revenues to change in oil prices is also illustrated.

FY 1989 PRICE/REVENUE SENSITIVITY OF CSHB164(fin) am
(Millions $)

	$10.00/bbl	11.00	12.00	13.00	14.00	15.00	16.00	17.00
Prudhoe	93.16	102.47	111.79	121.10	130.42	139.73	149.05	158.36
Kuparuk	21.54	23.69	25.84	28.00	30.15	32.30	34.46	36.61
Milne	0	0	0	0	0	0	0	0
Endicott	-6.49	-7.14	-7.79	-8.43	-9.08	-9.73	-10.38	-11.03
Lisburne	-3.72	-4.10	-4.47	-4.84	-5.21	-5.59	-5.96	-6.33
TOTAL	104.48	114.93	125.37	135.82	146.27	156.72	167.17	177.61

CHANGE IN REVENUE CSHB164
(Millions $)

YEAR	PRUDHOE	KUPARUK	MILNE	ENDI	LISB	W SAK	PT THOM	SEAL IS	NIAKUK	TOTAL
1988	130.03	30.30	0.00	-4.27	-5.93	0.00	0.00	0.00	0.00	150.15
1989	125.82	31.40	0.00	-9.46	-5.43	0.00	0.00	0.00	0.00	152.33
1990	172.12	39.56	0.00	-2.04	-6.19	0.00	0.00	0.00	0.00	203.45
1991	190.27	40.37	0.00	-2.25	-5.53	0.00	0.00	0.00	0.00	222.85
1992	183.74	39.61	0.00	-2.40	-7.01	0.00	0.00	0.00	0.00	213.94
1993	180.62	38.38	0.00	-5.24	-6.27	0.00	0.00	0.00	0.00	207.49
1994	178.59	36.55	0.00	-6.55	-6.74	0.00	0.00	0.00	0.00	199.74
1995	171.39	30.60	0.00	-7.41	-7.18	0.00	0.00	0.00	0.00	187.40
1996	162.83	22.19	0.00	-7.50	-7.83	0.00	0.00	0.00	0.00	169.69
1997	164.10	14.09	0.00	-7.32	-8.17	0.00	0.00	0.00	0.00	162.70
1998	157.08	6.98	0.00	-6.84	-8.44	0.00	0.00	0.00	0.00	148.78
1999	144.16	2.76	0.00	-4.29	-8.30	0.00	0.00	0.00	0.00	134.33
2000	137.86	1.22	0.00	-2.29	-8.44	0.00	0.00	0.00	0.00	128.35
2001	127.38	0.46	0.00	-0.61	-9.29	0.00	0.00	0.00	0.00	117.94
2002	118.80	0.08	0.00	0.00	-9.79	0.00	0.00	0.00	0.00	109.09
2003	122.08	0.06	0.00	0.00	-9.43	0.00	0.00	0.00	0.00	112.71
2004	116.55	0.04	0.00	0.00	-9.28	0.00	0.00	0.00	0.00	107.32
2005	103.90	0.03	0.00	0.00	-8.90	0.00	0.00	0.00	0.00	95.03
2006	91.47	0.00	0.00	0.00	-9.36	0.00	0.00	0.00	0.00	82.11
2007	80.19	0.00	0.00	0.00	-7.52	0.00	0.00	0.00	0.00	72.67
2008	69.43	0.00	0.00	0.00	-6.12	0.00	0.00	0.00	0.00	63.31
2009	61.76	0.00	0.00	0.00	-4.73	0.00	0.00	0.00	0.00	57.03
2010	55.85	0.00	0.00	0.00	-3.38	0.00	0.00	0.00	0.00	52.48

CHANGE IN SEVERANCE TAX RATE PERCENT OF VALUE CSHB164

YEAR	PRUDHOE	KUPARUK	MILNE	ENDI	LISB	W SAK	PT THOM	SEAL IS	NIAKUK
1988	0.0249	0.0391	0.0000	-0.0258	-0.0382	0.0000	0.0000	0.0000	0.0000
1989	0.0281	0.0448	0.0000	-0.0332	-0.0321	0.0000	0.0000	0.0000	0.0000
1990	0.0353	0.0481	0.0000	-0.0040	-0.0324	0.0000	0.0000	0.0000	0.0000
1991	0.0373	0.0513	0.0000	-0.0023	-0.0291	0.0000	0.0000	0.0000	0.0000
1992	0.0384	0.0539	0.0000	-0.0023	-0.0277	0.0000	0.0000	0.0000	0.0000
1993	0.0421	0.0550	0.0000	-0.0028	-0.0270	0.0000	0.0000	0.0000	0.0000
1994	0.0450	0.0545	0.0000	-0.0194	-0.0282	0.0000	0.0000	0.0000	0.0000
1995	0.0488	0.0491	0.0000	-0.0251	-0.0282	0.0000	0.0000	0.0000	0.0000
1996	0.0548	0.0405	0.0000	-0.0315	-0.0289	0.0000	0.0000	0.0000	0.0000
1997	0.0548	0.0334	0.0000	-0.0353	-0.0314	0.0000	0.0000	0.0000	0.0000
1998	0.0574	0.0171	0.0000	-0.0375	-0.0345	0.0000	0.0000	0.0000	0.0000
1999	0.0583	0.0083	0.0000	-0.0320	-0.0368	0.0000	0.0000	0.0000	0.0000
2000	0.0587	0.0042	0.0000	-0.0231	-0.0373	0.0000	0.0000	0.0000	0.0000
2001	0.0585	0.0017	0.0000	-0.0102	-0.0391	0.0000	0.0000	0.0000	0.0000
2002	0.0585	0.0001	0.0000	0.0000	-0.0413	0.0000	0.0000	0.0000	0.0000
2003	0.0589	0.0000	0.0000	0.0000	-0.0426	0.0000	0.0000	0.0000	0.0000
2004	0.0592	0.0000	0.0000	0.0000	-0.0433	0.0000	0.0000	0.0000	0.0000
2005	0.0598	0.0000	0.0000	0.0000	-0.0440	0.0000	0.0000	0.0000	0.0000
2006	0.0462	0.0000	0.0000	0.0000	-0.0475	0.0000	0.0000	0.0000	0.0000
2007	0.0409	0.0000	0.0000	0.0000	-0.0434	0.0000	0.0000	0.0000	0.0000
2008	0.0344	0.0000	0.0000	0.0000	-0.0411	0.0000	0.0000	0.0000	0.0000
2009	0.0339	0.0000	0.0000	0.0000	-0.0357	0.0000	0.0000	0.0000	0.0000
2010	0.0309	0.0000	0.0000	0.0000	-0.0314	0.0000	0.0000	0.0000	0.0000

APPENDIX B

ALASKA NORTH SLOPE ECONOMICS *

Weighted Average of West and Gulf Coast Sales as Reported in PIW

	REVENUE, COSTS &INCOME PER BARREL			
	1985	1986	1987	1988
Wellhead price/barrel	$16.72	$10.17	$7.54	$9.47
LESS:				
Royalty/barrel	$2.01	$0.73	$0.86	$1.10
Severance/barrel	$2.21	$0.87	$1.00	$0.99
Property tax/barrel	$0.21	$0.18	$0.16	$0.15
Producing cost/barrel	$0.90	$0.75	$0.80	$0.85
Depreciation/barrel	$1.53	$2.17	$2.21	$2.25
State income tax/barrel	$0.29	$0.06	$0.08	$0.12
US income tax/barrel	$4.54	$0.84	$0.89	$1.40
PLUS:				
Pipeline profit/barrel	$2.18	$0.64	$0.58	$0.43
EQUALS:				
Industry profit/barrel	$7.22	$1.56	$2.13	$3.03

	NET INCOME SHARES			
Shares in dollars per barrel				
Industry profits/barrel	$7.22	$1.56	$2.13	$3.03
State & local rev./barrel	$4.71	$1.84	$2.10	$2.37
Federal rev./barrel	$4.54	$0.84	$0.89	$1.40
Shares in billions of $ per year				
Industry profits/year	$5.004	$1.102	$1.530	$2.211
State & local revenue/year	$3.269	$1.294	$1.512	$1.728
Federal revenue/year	$3.148	$0.592	$0.640	$1.022
Shares in percent of total				
Industry profits	43.8%	36.9%	41.6%	44.6%
State & local revenue	28.6%	43.3%	41.1%	34.8%
Federal revenue	27.6%	19.8%	17.4%	20.6%

	ALASKA REINVESTMENT PERFORMANCE			
Reinvestment in billions $/year				
Cash flow (billions $/year)	$6.065	$2.630	$3.119	$3.853
Reinvestment (billions $/year)*	$0.860	$1.322	$0.650	$0.700
Reinvestment in $/barrel				
Cash flow per barrel	$3.75	$3.73	$4.34	$5.28
Reinvestment per barrel*	$1.24	$1.88	$0.90	$0.96
Percentage reinvested in Alaska	14%	50%	21%	18%

** Revenue, costs and income data from Petroleum Intelligence Weekly (attached); reinvestment performance estimated by the Division of Policy.*

See the following page for additional notes.

Division of Policy, 4/11/88

Notes to analysis of *PIW* data on North Slope economics:

1. PIW data for the first and second half of 1986 and 1987 were averaged using equal weights to produce the average annual values shown on the preceding page.

2. PIW values stated separately for U.S. West and Gulf coasts were combined to provide weighted average figures; the following weighting factors were used (West/Gulf): 1985-50%/50%; 1986-52.5%/47.5%; 1987-56.66%/46.67%; 1988-60%/40%.

3. Annual revenue figures assume production levels of 1.90 MMB/D, 1.93 MMB/D, 1.96 MMB/D, and 2.00 MMB/D in 1985-88 respectively.

4. Data for 1988 are extrapolated assuming costs and revenues continue at the per barrel levels reported in *PIW* for the first two months of 1988.

5. Reinvestment estimates for 1985-6 are from Income and Investment Flows From Alaska Oil and Gas Producing Activities, by Edward Deakin, May, 1987. Estimates for 1987-8 are Division of Policy estimates based on industry statements of current and planned project activity.

6. Cash flow is understated by an estimated $2.00 per barrel because depreciation on pipeline investments are not accounted for separately in the *PIW* data. (Pipeline tariffs are deducted before determining the wellhead price per barrel.)

Division of Policy
11 April 1988

FOUNDED 1961. Vol.XXVII No.5 February 1, 1988

PETROLEUM INTELLIGENCE WEEKLY®

Short-Haul Sales By Saudis Key To Overseas Stockbuild

Oil markets should be very careful in drawing grand conclusions about Saudi Arabia's oil policies on the basis of its latest foray to charter ships for moving crude oil into its overseas stockpile. The fact is that Saudi Arabia is in the process of placing a large chunk of stockpile crude with several of the Aramco partners on a delivered basis, and it chartered the tankers almost entirely to replenish those supplies, according to well informed PIW sources in shipping circles. The stockpile moves say more about Riyadh's wish to retain a basic presence as a short-haul crude supplier in the Caribbean and Europe (p5) than about its long-term goals or role within Opec (PIW Jan.25,p1). PIW confirms that the Saudis have lined up five ships to move 10-million barrels of oil into overseas storage in the coming weeks, plus at least one other vessel to supply non-Aramco clients like Ashland and Marathon. In the past, the Saudis have used the Western Hemisphere stockpile for occasional spot sales, and more routinely to supply term customers on a prompt basis.

By taking nearby crude from the stockpile now, the Aramco partners get the benefit of the oil in the heart of the winter season, rather than in late March or early April when oil loaded today in Saudi Arabia would arrive at Atlantic Basin destinations. The stockpile barrels are within the overall 1.4-million b/d of crude the partners obtained from the Saudis in January, and are expected to take in February. They do not represent any extra supply. Overall Saudi output volume is still below Opec quota in the 3.8- to 4-million b/d range (excluding the Neutral Zone). This suggests Riyadh is willing to cautiously and temporarily stick with other Opec producers in sharing some of the burden of

(continued on p.4)

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Alaskan Oil Profits Staying Buoyant Amid Volatile Prices

With oil markets again threatening a possible sharp drop in prices, US Alaskan production looks surprisingly well positioned to cope with a repeat of the collapse of 1986. Despite high transport costs that would appear to make Alaskan North Slope output highly vulnerable to lower prices, it is currently making good profits at $14.50-$15.50 delivered prices, and has shown it can break even at $10 a barrel. Profits also bounce back quickly as prices recover, according to a PIW analysis of Alaskan North Slope economics (see table). Producers briefly suffered losses of a few pennies a barrel in mid-1986 when the delivered price at the Gulf Coast fell to $10. But profits rebounded to an average $3.50 in 1987, and even managed to average over $1 a barrel in disastrous 1986. ANS crude — which is one-fourth of US production — realizes a healthy $2.60-$3.20 a barrel now, depending on sales destination.

Even if prices dropped below $10, very little North Slope production would be shut in, mainly because of the large amounts already invested in current output and its importance to US supply. What's more, the oil is primarily absorbed into the refining and marketing systems of producing companies, and low crude prices usually provide

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LONDON: 121 Charterhouse Street, EC1M 6AA; Phone (01)608-1321; Telefax (01) 608-1324. SUBSCRIPTIONS: $1,150 annually to all areas by air or courier

offsetting improvements in the profitability of downstream refining. Meanwhile, the long-term outlook for Alaskan North Slope crude is encouraging a continuing buildup of production capacity, in sharp contrast to plunging production in other US areas. ANS output surged over 2-million b/d in late 1987 as Alaska displaced Texas for the first time as the largest source of US crude. The North Slope is still regarded as holding the best potential for finding big new fields. But discoveries have to be large to offset growing development and operating costs, already apparent at the Kuparuk River and Endicott fields, and for enhanced recovery in super-giant Prudhoe Bay (PIW Jan.25,p10).

Since the 1986 price collapse, the economics for Alaskan North Slope crude sold on the West Coast have become relatively more profitable than the longer shipments to the Gulf and East Coasts, which used to earn almost as much. As a result, more North Slope crude is moving to the California market, with the West Coast absorbing 60% of last year's higher production versus 50% in 1985. Profits on West Coast sales are now about 65¢ a barrel higher than those to Atlantic ports, compared to a gap of 10¢ in 1985. This mainly reflects the much larger $11.66 a barrel drop in ANS prices to Gulf and East Coast destinations in the last two years compared to a drop of just under $10 on the West Coast. The bigger decline in the east is hard to explain but is probably only partly due to the highly competitive Atlantic Basin crude oil market.

THE COMPARATIVE ECONOMICS OF ALASKAN NORTH SLOPE PRODUCTION (In dollars per barrel)

	Sales To US Gulf Coast						Sales To US West Coast					
	1988	1987		1986		1985	1988	1987		1986		1985
Delivered Price	Current	2nd H	1st H	2nd H	1st H	Year	Current	2nd H	1st H	2nd H	1st H	Year
Sohio Price	$15.50	$18.45	$17.00	$12.00	$16.80	$27.00	$14.50	$17.45	$16.00	$11.00	$15.80	$25.00
Average Price(a)	15.25	16.82	16.95	12.31	15.72	26.91	14.25	15.48	15.56	10.75	14.54	24.23
Less:												
Shipping Cost	3.35	3.21	3.19	3.38	3.72	4.21	0.99	0.96	0.94	0.94	1.14	1.29
Valdez f.o.b.	11.90	13.61	13.80	8.93	12.00	22.70	13.26	14.52	14.62	9.81	13.40	22.94
Less:												
Pipeline Loss	0.05	0.10	0.05	0.05	0.05	0.10	0.05	0.10	0.05	0.05	0.05	0.10
Pipeline Tariff	3.20	3.95	3.95	4.50	4.50	6.00	3.20	3.95	3.95	4.50	4.50	6.00
Wellhead Price(b)	8.65	9.56	9.80	4.38	7.45	16.60	10.01	10.47	10.62	5.26	8.85	16.84
Less:												
Royalty(c)	1.00	1.11	1.14	0.47	0.85	1.99	1.17	1.23	1.24	0.58	1.02	2.02
Severance(d)	0.91	1.00	1.30	0.59	0.99	2.19	1.05	1.09	1.40	0.70	1.17	2.22
Property Tax	0.15	0.15	0.15	0.18	0.18	0.21	0.15	0.15	0.15	0.18	0.18	0.21
Producing Cost	0.85	0.85	0.85	0.75	0.75	0.90	0.85	0.85	0.85	0.75	0.75	0.90
Depreciation(e)	2.25	2.25	2.25	2.17	2.17	1.53	2.25	2.25	2.25	2.17	2.17	1.53
Pre-Tax Profit	3.49	4.20	4.11	0.23	2.51	9.78	4.54	4.90	4.72	0.88	3.56	9.96
Less:												
State Income Tax(f)	0.10	0.13	0.12	0.01	0.08	0.29	0.14	0.15	0.14	0.03	0.11	0.30
US Windfall Tax(g)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
US Income Tax(h)	1.19	1.43	1.40	0.11	1.16	4.50	1.54	1.67	1.61	0.41	1.64	4.58
Oil Profit	2.20	2.64	2.59	0.12	1.28	4.99	2.86	3.09	2.98	0.45	1.81	5.08
Pipeline Profit	0.43	0.53	0.53	0.64	0.64	2.18	0.43	0.53	0.53	0.64	0.64	2.18
Overall Profit	2.63	3.17	3.12	0.76	1.92	7.17	3.29	3.62	3.51	1.09	2.45	7.26

a) Average of all producers. b) Price at Pump Station #1. c) Royalty 12.5% after deduction of gathering costs (63¢ 1988, 66¢ 1987 & 1986, 65¢ 1985). d) Severance Tax based on wellhead price after deduction of royalty (11.94% from 2nd Half 1987 to present, 14.96% 1985 to 1st Half 1987. e) Includes depletion. f) Average state income tax rate of 3% for all producers. g) Windfall profits tax not applicable at lower wellhead prices. h) US income tax rate 34% 1987 to present and 46% previously, after deduction of costs, state taxes.

Another big change in the last few years is the more even split between producing company profits and the tax take of federal and state governments. With Alaskan wellhead prices well below the floor level of US "windfall" taxation, the tax burden has shrunk to an estimated $3.35 a barrel currently. Reduced corporate income tax rates from 46% to 34% starting in 1987 has also helped producers. However, Washington claims that the companies may owe $200-million in "windfall" profits taxes for 1984 and 1985 due to disparities in pricing and pipeline charges among the various Alaskan oil producers (PIW June 13,'83,p3).

The settlement of a 7-year legal dispute over Alaskan pipeline tariffs has also put an extra squeeze on profits since 1986, with the Trans-Alaskan Pipeline providing 15% of North Slope profits now compared to 30% in 1985. Aimed at fostering greater competition for North Slope leases, the resolution with the seven owners (BP 50%, Exxon and Arco

20% each, and the rest split between Mobil, Phillips, Union and Amerada Hess) sharply reduced tariffs, settled back claims of overcharges and put the pipeline on a real-rate-of-return basis starting in 1986 (PIW Nov.4,'85,p8).

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US ...n't End ...ans For ... ...ole

The existence of a semi-secret and unofficial "mini-Brent" North Sea market might help London's International Petroleum Exchange win a central role in the globalization of oil futures dealing. Mini-Brent could provide a model for the IPE as it prepares another relaunch for its failed Brent futures contract following the New York Mercantile Exchange's refusal to trade US crude futures in London as a joint venture (PIW Jan.25,p8). Shocked and disappointed by Nymex's rejection of joint trading of West Texas Intermediate futures, the IPE is considering a number of alternative options, with a restyled 1,000-barrel Brent contract based on cash settlement rather than physical delivery at the top of the list (PIW Jan.25,p8). Other possibilities include a London-based West Texas Intermediate contract administered independently of Nymex, and a link to another US exchange such as the Chicago Board of Trade, which dabbled with oil futures several years ago.

Steady but largely unpublicized trade in the unregulated mini-Brent market leaves little doubt that demand exists for a financial tool of this type geared to European crude. Also known as the Brent partial market, and only reluctantly revealed to PIW by major players, mini-Brent is the brainchild of US investment banks. But its future is now in doubt due to new UK laws which may leave room for the IPE to take over instead. Mini-Brent works because the investment banks are willing to buy and sell futures contracts for part-cargoes of Brent in 50,000 barrel increments under their own set terms, normally closing out at an agreed cash-settlement price as 600,000-barrel forward Brent cargoes begin to trade in the physical market. However, this trading could fall foul of the forthcoming UK Financial Services Act (PIW Jan.11,p2). The IPE, as a recognized futures exchange, might win approval of a similar standard contract, using well-established procedures of exchange-of-futures-for-physicals for participants wanting to take delivery. The IPE is now seeking industry advice on how to tailor a new contract, but there's virtually universal agreement that simply restyling the existing 1,000-barrel contract won't work.

Even with its poor track record in marketing and planning, the London futures exchange is still eager to launch its own crude contract that will spark trade both locally and from Mideast and Far East time zones, largely out of New York's normal reach. It plans "some form of significant trading incentive scheme to encourage initial participation" and scope for broader membership, aimed at attracting more active floor traders. While Nymex boasts almost 800 members and last year traded an average 40-million b/d, there are currently just 57 authorized IPE dealers. There's general dismay in European trading circles over the Nymex's "parochial" decision not to come to London, coupled with the recognition that Eastern Hemisphere traders increasingly want to use crude futures (PIW Dec.7,p6). The IPE has already been approached by the Singapore International Monetary Exchange on possible broad cooperation.

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In Opec ...tives To ...counting

Like the big Mideast exporters, Opec's key African members are moving fast to cushion themselves against rapid swings in output even in a weak market. But they are using very different means to achieve the same ends. Resisting straight market-related pricing, the Africans are looking to product sales, processing deals of various kinds and enhanced margins for foreign equity producers to sustain volumes. Though techniques differ, almost all Opec exporters are adapting to an oil market in which some price volatility is seen as inevitable, making maintenance of sales to key customers in ways that cause the least market disruption a top priority (PIW Jan.25,p1). The various methods reflect marketing strengths of individual producers and preferences of traditional customers, among other factors.

Among African producers, Libya appears to have significantly reduced its vulnerability to short-term market swings. Though volume has fallen somewhat, Tripoli seems to be offsetting much of the recent loss of up to 200,000 b/d in third-party crude sales to traders without flooding the Mediterranean with discounted crude. "They've

APPENDIX C -- EXPLANATION OF 1981 OIL TAX LAW CHANGES

I. Introduction

The 1981 oil tax legislation (ch. 116, SLA 1981) replaced the separate accounting oil and gas corporate income tax, enacted in 1978, with a modified apportionment- based corporate income tax. To make up the substantial loss in revenues caused by this shift, the legislation also raised the severance tax rate on Prudhoe Bay from an effective rate of just over 11% (with the ELF) to 15%. This increase was accomplished by raising the nominal rate from 12.25% to 15% and effectively suspending the ELF until the tenth anniversary of Prudhoe Bay production in 1987. (For fields beginning production after June 1981, the nominal rate was set at 12.25% for the first five years of production.) Taken together, the two changes were intended to be revenue neutral.

In addition to the two primary changes -- eliminating separate accounting and increasing the severance tax -- the 1981 law also:

(a) made retroactive technical amendments (known as the "warts" amendments) to state tax laws in order to improve the retrospective constitutionality of separate accounting;

(b) corrected tax problems posed by the sharing of oil and gas revenues among Native corporations under §7(i) of the Alaska Native Claims Settlement Act;

(c) allowed for the retroactive deduction of federal windfall profit tax payments; and

(d) instituted a graduated, stair stepped rate, beginning at 1%, for the taxation of corporate income under $100,000, and raised the top rate from 9.4% to 11% for one year.

Tax "stability" was not the issue in 1981. The 1981 law was passed solely in response to litigation filed by the oil industry challenging the 1978 separate accounting corporate income tax. Unlike the separate accounting law, which was passed after nearly a decade of study, discussion, and debate, the 1981 oil tax changes were not designed to make the state's tax system fair and predictable, or to encourage future exploration and production. Instead, the 1981 law was designed to limit the state's potential liability as a result of the oil companies' legal challenge to the 1978 separate accounting law. Because the oil industry benefitted from the 1981 law, it did not object to the changes in the state's oil tax structure.

At the time the 1981 law passed, many assumed that the oil tax issue would be revisited, after a decision on the 1978 law was made, and before the June 1987 reimposition of the ELF. The state won the separate accounting litigation in the trial court in May 1983 and on appeal to the Alaska Supreme Court in August 1985. The statute's constitutionality was affirmed by the U.S. Supreme Court in January 1986.

II. How It Happened

A. Activity Before 1981

The 1977-78 Alaska Legislature and Hammond Administration, confronted with the prospect of the first commercial production from Prudhoe Bay, instituted a comprehensive revision of the state's oil and gas tax structure. In 1977, the legislature, with the active support of the governor, increased the maximum severance tax rate from 8% (first put in effect in 1970) to 12.25%. An economic limit factor [ELF] formula replaced the statutorily-reduced rates for well production less than one thousand barrels per day (from 1973-1977, a well's first 300 barrels were taxed at 5%, and the next 700 barrels at 6%). The ELF was designed to give the severance tax a curved or sliding scale, instead of stair stepped, rate.

In 1978, the separate accounting oil and gas corporate income tax was enacted. The law was developed and passed in response to detailed analyses, prepared for the legislature and administration from 1970-78, showing that the state's existing apportionment-based corporate income tax would result in Prudhoe Bay oil producers paying less than a third of the statutory rate of 9.4% of net income. The apportionment tax also had the inequitable effect of imposing different tax levels on producers with the same profits in Alaska, in effect penalizing producers with a larger degree of investment and employment in Alaska.

In early 1979, the major Prudhoe Bay oil producers filed suits challenging the constitutionality of the 1978 separate accounting law. Concerned over the amount of revenues at risk in the litigation, in the fall of 1980 the Hammond Administration engaged in substantive settlement discussions with those companies. The options proposed would have required the sacrifice of several hundred million dollars of state revenue in order to settle the litigation.

B. The 1981 Session -- Policy Background

At the beginning of the 1981 session, House and Senate leaders urged the Administration to pursue solutions to the problems posed by the oil industry suit that would not require revenue losses to the state. On March 18, 1981, the leadership of

both chambers, including Senate President Kerttula and Finance Chairmen Dankworth and Bennett, House Speaker Duncan and Finance Chairman Cotten, and Governor Hammond, Attorney General Condon, and Revenue Commissioner Tom Williams, joined in a statement declaring that "any significant decreases in state oil and gas revenues appear both unwarranted and unsupported by a majority of Alaskans. . . . 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."

House leaders did not agree with the Administration's view that existing law needed to be changed. They were more optimistic that the separate accounting statute would be upheld, as it was in 1986. They believed that the tax structure put in place in 1977-78 was sound, and preferable to the alternatives of a higher severance tax or an apportionment- based income tax. They also believed any changes to state tax laws should be made after, not prior to, any unfavorable court decision, and that the potential problem of having to refund money to the oil industry was better left to the future, if and when it was more than a hypothetical possibility.

C. The 1981 Legislation

Because the Administration felt that some action was required to limit the risk posed by the separate accounting lawsuit, the House developed a "backstop" bill (in conjunction with the Administration), which set an oil and gas reserves tax in place to take effect and preserve state revenues if the 1978 separate accounting law were to be found unconstitutional.

Governor Hammond introduced the backstop bill in May 1981 (as SSHB 200). It passed the House (as SB 524) in early June. A free conference committee, consisting of Senators Ray, Bennett, and Dankworth, and Reps. Gardiner, Vaska, and O'Connell, first met on June 11.

During the latter half of the session, Senator Dankworth had attempted to develop a bill that would succeed in settling the separate accounting litigation while preserving, in substantial part, past and future state oil revenues. He was unsuccessful, and gave up the idea of ending the existing separate accounting litigation. He then attempted to craft a bill that would repeal the separate accounting law prospectively and maintain future state oil revenues at a level roughly comparable to those collected under the separate accounting law.

On June 17, following the reorganization of the House, Rep. Halford replaced Rep. Vaska on the conference committee and became the House chair. At that time, the oil industry circulated a settlement proposal which repealed separate accounting, increased severance taxes, and instituted a 10% investment tax credit. The oil

industry estimated the proposal's revenue loss to the state for FY 82-85 at $1.37 billion; legislative staff estimates of revenue losses ranged from $1.5 to $2.1 billion.

Senator Dankworth prepared a draft bill embodying the settlement proposal, and distributed it to the conference committee on June 22. At a later point in the June 22 meeting, he also distributed a draft bill that modified the settlement proposal in two important ways, in order to make the bill as revenue neutral as possible. He abandoned the 10% investment credit and suspended the application of the ELF during a field's first ten years of production in order to achieve a 15% effective severance tax rate at Prudhoe Bay. As a result of these changes, the oil industry was not willing to settle the litigation, and stated in testimony that they would continue the separate accounting litigation even if the modified proposal were enacted.

Prior to the next meeting of the conference committee on June 23, Governor Hammond wrote a letter to all legislators clarifying his position on the oil tax issue. He stated his preference was for a public vote on the backstop bill versus the oil industry settlement proposal. Alternatively, he urged the Senate to pass the backstop bill, and stated he preferred passage of any proposal to doing nothing. He noted that legislative action should "[r]educe the likelihood that the oil tax issue will continue to be a perennial political liability for those in public office."

On June 23, Senator Dankworth submitted to the conference committee the legislation ultimately signed by Governor Hammond, described on the first page of this appendix. The June 23 bill, known as "Dankworth 3," retained the basic characteristics of Senator Dankworth's earlier proposal, but suspended the application of the ELF during the first ten years of production only if the ELF was greater than .7. The change did not affect Prudhoe Bay, but did provide a tax break for Kuparuk.

The June 23 legislation received only cursory examination in the free conference committee and on the floor of the House and Senate before its passage on June 24. No committee report or written analysis was provided by either the bill's sponsor, Senator Dankworth, or the Administration. A bare bones fiscal note, which projected total revenue losses from FY 82-85 of $141 million, did accompany the bill during the legislature's deliberations. Specifically, the note showed revenue losses of $21 million in FY 82, $117 million in FY 83, $18 million in FY 84, and a gain of $15 million in FY 85. No figures for the effect of the reimposition of the ELF on Prudhoe Bay in 1987 were provided. Revenue Commissioner Williams personally prepared the fiscal note and provided no supporting documentation for it, other than stating the estimates were based on confidential figures provided by the oil industry.

Speaker Hayes refused to allow a minority report opposing the legisla ı,

authored by Rep. Gardiner, to be published in the House Journal. At pages 2-3 of the minority report, after questioning the validity of the $141 million estimate, Rep. Gardiner stated the fiscal note "failed to point out an even more significant revenue loss which will occur in the latter half of this decade, due to the sharp decline in severance tax collections from Prudhoe Bay after the reimposition of the economic limit factor in 1987. This loss is on the order of two billion dollars." (The two billion dollar estimate was based on the optimistic oil price assumptions prevailing at the time.) The bill passed over the strenous objections of the former House majority.

At the time he signed the 1981 law, Governor Hammond noted that the new law would only reduce state income by .6%, relying on the figures in the fiscal note.

The key arguments made in opposition to the 1981 law were:

(a) It was not revenue neutral, because the estimates for the amounts to be collected by the new apportionment formula were overstated and speculative.

(b) A future legislature and administration would be saddled with a huge drop in revenues by the reimposition of the ELF in 1987.

Other arguments concerned the harmful effects of a shift from a net income-based separate accounting tax to a gross revenue severance tax.

Both Commissioner Williams and Governor Hammond explicitly recognized that a future legislature would have to deal with the post-1987 revenue effects from reimposition of the ELF. In the press statement issued on July 21, 1981, at the time he signed the oil tax bill, Governor Hammond declared, "As for the possible revenue effects in 1988 and beyond, I have full confidence in the ability of the Legislature to deal at that time with whatever is required to retain the state's 'fair share' of our oil wealth."

In responding to a question about the post-1987 ELF revenue loss at the June 23 conference committee meeting, Commissioner Williams noted that a future legislature would have the option of reimposing separate accounting if it proved constitutional. A newspaper account of the meeting reported that "If the projected revenue loss proves true, Williams said the Legislature would have the option of hiking taxes." (*Anchorage Daily News*, June 25, 1981, p. A4, "Lawmakers Pass Revision of Oil Tax Law.")

During the June 24 House floor debate on the 1981 bill, Rep. Gardiner noted the ELF factor would cause multi-hundred million dollar losses after 1987. Rep. Halford responded that "by that time [1987], if the companies continue to challenge the portion of funds that are in the state's hands under chapter 21 [separate accounting], we should have an answer to that lawsuit. And with that answer, we should be able to develop possibly a more consistent taxing policy at that time. That's

pretty far in the future, but we'll have more information available to us at that time."

III. Postscript

The revenue losses resulting from the shift to the modified appportionment method have exceeded considerably the $141 million estimate for FY 82-85 made in 1981 by Commissioner Williams. Analyses by the Department of Revenue shows the FY 82-85 revenue loss of the 1981 law at over seven hundred million dollars. Through FY 87, the state lost over one billion dollars in revenue as a result of passage of the 1981 law.

The problems arising from the reimpostion of the ELF are the subject of the main body of this report.

Appendix D

DRILLING/WORKOVER DISINCENTIVE
COMMITTEE SUBSTITUTE HB 164

SEVERANCE TAX CALCULATION

CURRENT LAW

Field Rate x *Wellhead Price* x *Severance Tax* x *ELF*

90,168,000 *BOPY* x $9/*BO* x 0.15 x 0.52134

= $63,461,050/year

Addition of 1 well:

90,277,000 *BOPY* x $9/*BO* x 0.15 x 0.5204

=$63,423,203/year

A decrease of $37,846 year

PROPOSED LAW

Field Rate x *Wellhead Price* x *Severance Tax* x *ELF*

90,168,000 *BOPY* x $9/*BO* x 0.16 x 0.7296

=$88,811,873/year

Addition of 1 well:

90,277,000 *BOPY* x $9/*BO* x 0.15 x 0.7292

=$88,870,484/year

An increase of $58,611 year

[Copy of ARCO Handout, March 27, 1987]

TECHNICAL NOTE
ON ARCO'S KUPARUK EXAMPLE

Tax Effects of Drilling an Additional Well Under Current Law

Mr. James Weeks, Kuparuk Unit Manger for ARCO, provided testimony to the House Finance Committee on March 27, 1987. Examples of severance tax effects (see preceding page) accompanied his testimony. The examples compare the severance tax effects of adding one additional well in the Kuparuk field under the current ELF and under the proposed ELF. The examples show that the addition of one well producing just under 300 barrels per day would increase output from 90,168,000 barrels of oil per year (BOPY) to 90,277,000 BOPY. At the $9.00 per barrel price assumed in ARCO's example, annual gross revenue to the owners increases by $981,000.

(90,277,000 BOPY - 90,168,000 BOPY)*($9/barrel) =
(109,000 BOPY)*($9/barrel) = $981,000

The first of ARCO's two examples shows how under current law the owners would collect an annual severance tax *rebate* of $37,846 on this additional revenue. The effective severance tax rate on the new production is thus -3.9 percent. The effect is analagous to a personal income tax where the effective tax rates become lower as increasing income moves the taxpayer into a higher bracket.

The second ARCO example illustrates how this will be changed under the proposed law. Instead of giving the owners a $37,846 windfall, the proposed law will collect $58,611 (6.0 percent) of the incremental $981,000 for the state in severance tax. The table below summarizes the effects under the current and proposed severance tax laws, as shown in the ARCO examples.

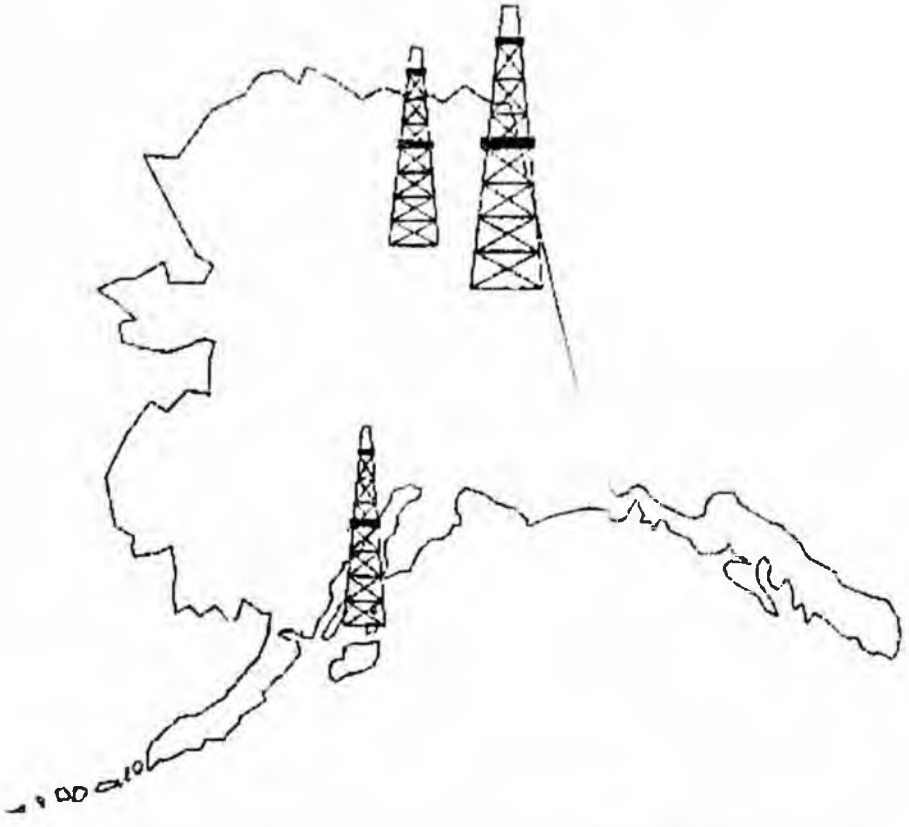
TAX EFFECTS OF DRILLING ONE ADDITIONAL WELL
(ARCO Kuparuk Example)

	Change In Annual Gross Revenue	Annual Severance Tax	Tax Rate On Incremental Production	Average Tax Rate Before Drilling	Average Tax Rate After Drilling	Percent Change In Average Tax Rate Due To Drilling
Current Law	$981,000	($37,846)	-3.9%	7.820%	7.806%	-0.180%
Proposed Law	$981,000	$58,611	6.0%	10.944%	10.938%	-0.055%

Prepared by Division of Policy, April 1987.

f - ELF

Oil Industry Profitability in Alaska 1969 through 1987



Prepared for the Department of Revenue
State of Alaska

by

Edward B. Deakin

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Director, Institute of Petroleum Accounting
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University of Texas

March 15, 1989

Edward B. Deakin is the Distinguished Enterprise Professor at the University of North Texas in Denton, Texas. He directs the Institute of Petroleum Accounting there. He is on leave from his position as the Price Waterhouse Centennial Professor of Accounting at the University of Texas and has also held professorships at Stanford University and the University of Kuwait. Professor Deakin has written more than fifty articles and books, many of which addressed issues in the field of petroleum accounting. He has been an advisor to the U.S. Departments of Energy, Interior, and Treasury on issues related to oil industry accounting. He has also advised several state governments, including the State of Alaska, as well as a number of private companies. He served on two task forces of the Financial Accounting Standards Board which dealt with oil industry accounting matters. He holds a Ph.D. from the University of Illinois and C.P.A. certificates from the states of Illinois and Texas.

Department of Revenue Press Release

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March 15, 1989

A petroleum accounting expert says the oil industry has earned more than $42 billion in Alaska in after-tax profits from 1969 through 1987 -- including more than $460,000 per hour since the super-giant Prudhoe Bay field began producing in 1977.

According to the study by University of Texas Professor Edward B. Deakin, the industry's share of profits from Alaska operations since 1969 is 45 percent greater than the $29.3 billion received by the state. The state collects oil revenues through royalty, tax and lease payments.

Most of the oil company profits leave the state. The study found that the oil industry's cash flow, which includes profit and repayment of original investment, has exceeded $61 billion. The study calculates that the industry has re-invested approximately 28 percent of its cash flow in Alaska since Prudhoe Bay began producing in 1977.

Industry after-tax profits in Alaska in 1986 and 1987 averaged more than $8 million per day. In 1986 -- the year following a sharp decline in the world price of oil -- Deakin found that Alaska North Slope production and pipeline profits were $5.23 per barrel. In 1987 that figure rose to $5.47 per barrel. The industry's $42.6 billion in profits since 1969 represents a profit of $6.59 per barrel for all Alaska activities.

Deakin's study focuses primarily on North Slope production and the trans-Alaska pipeline, which account for $41.5 billion of the industry's Alaska profits since 1969. His analysis does not consider additional profits earned by the North Slope operators on transportation, marketing and refining of Alaska crude oil after it leaves the state.

The 110-page accounting analysis, prepared under contract to the Department of Revenue, is based on public documents, including annual reports and corporate filings with the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state publications and reports by financial analysts.

In addition to his position as Price Waterhouse Centennial Professor of Accounting at the University of Texas at Austin, Deakin is also Distinguished Enterprise Professor and Director of the Institute of Petroleum Accounting at the University of North Texas. He is a certified public accountant, holds a Ph. D. and has served on two task forces of the Financial Accounting Standards Board (F.A.S.B.) which dealt with oil industry accounting matters. He has advised the federal government, as well as various states and companies on issues related to oil industry accounting.

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SUMMARY

Total Profit. The oil industry received an estimated $42.6 billion in profit from production and transportation activities in Alaska from 1969 through 1987. The $42.6 billion represents amounts accruing to producers after accounting for all expenses, including exploration, lease acquisition and income taxes, and allowing for recovery of investment costs (depreciation). The main section of this report presents details of profit for each calendar year. The technical section of this report describes each component of the profit, investment and cash flow elements. Below is a summary statement.

Total Alaska Oil Profit
1969 through 1987
(billions of dollars)

Revenues:		
Production revenues	$ 97.6	
TAPS revenues	33.7	
Total Revenues		**$131.3**
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		88.7
Profit		**$ 42.6 Billion**

Profit per barrel: $6.59

Alaska North Slope (ANS) production contributed $29.1 billion to profit, with $27.8 billion of this amount attributable to Prudhoe Bay and $1.3 billion

attributable to Kuparuk. TAPS provided $12.4 billion. Production in Alaska other than ANS production added $1.1 billion in profit. (Lisburne is included with Prudhoe Bay and Milne Point with Kuparuk. Endicott did not have significant production until after 1987. Alaska production other than ANS production is at Cook Inlet).

Shares. The $42.6 billion in after-tax profit that accrued to the oil industry compares to $29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were $25.8 billion from these activities.

Investment. From 1969 through 1987, the industry invested $25.0 billion in ANS development costs and for TAPS. $13.1 billion of this represents the initial costs of Prudhoe Bay and TAPS. Of the $25.0 billion investment, $11.6 billion has been recovered through depreciation charges ($6.6 billion from Prudhoe, $1.0 billion from Kuparuk and $4.0 billion from TAPS).

Rates of Return on Investment. Cash flows from all Alaska investments from 1976 through 1987, assuming no debt, total $61.3 billion ($41.8 billion of profit plus $12.0 billion of depreciation plus $7.5 billion of interest[1]). Comparing these cash flows to the investment amounts over time implies that the after-tax rate of return on Alaska investments has been 29.7% from 1976 through 1987. Assuming that 75% of the initial investment was borrowed, an assumption that is indicated by available data, the rate of return on the investment is 43.7% after tax.

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[1]Interest is added back under the assumption of no debt because there would be no interest expense if the entire project were funded with equity. This analysis incorporates all ANS investments prior to 1976 into 1976 and 1977. A more detailed timing of these investments was beyond the scope of this study. As indicated in the technical discussion, the effects of this assumption create minimal changes in the results.

These rates of return compare to the long run rate of return on the New York Stock Exchange of 10% *before* tax. [*Wall Street Journal* (February 20, 1989)] The prime rate peaked at 21.5% *before* tax in 1982, but that was an exceptional year. During this period, a prime rate of 10% to 18% *before* tax was more typical. Using an average effective tax rate of 36%, which approximates the tax rate observed in this study, the equivalent after-tax return on the New York Stock Exchange is 6.4%. The equivalent peak prime rate after an effective tax rate of 36% is 13.76%.

Reinvestment of Alaska Cash Flows. Subsequent to the initial investment for Prudhoe Bay field and TAPS, the industry invested $15.8 billion for ANS development and exploration throughout Alaska from 1978 through 1987. This includes $3.9 billion in exploration expenses which are not included in the analyses of profits from individual fields. The reinvestment rate has been 27.8% of cash flows received during this period.

Seventy-five sources of data about Alaska oil operations were researched to develop this report. Although details do not exist on each and every data item, the information available in the references is sufficient to develop a reasonably accurate picture of industry profit. A study of the data suggests that the actual profit number could be as low as $41 billion or as high as $47 billion. The estimate reported here is at the conservative end of this range.

Oil Industry Profit in Alaska: 1969-1987
Overview

How profitable is the oil industry in Alaska? This is a question of major significance to the State of Alaska and to its residents because the State's share of the revenues from oil production and transportation activities are a primary factor in determining the State's General Fund revenues as well as the additions to the Permanent Fund. This report looks at available information on industry activities in Alaska to derive a picture of the profit attained from these activities. The results of the study indicate that the oil industry received $42.6 billion in after-tax profit from 1969 through 1987 from oil production and from TAPS. The components of this profit estimate are given in Table 1:

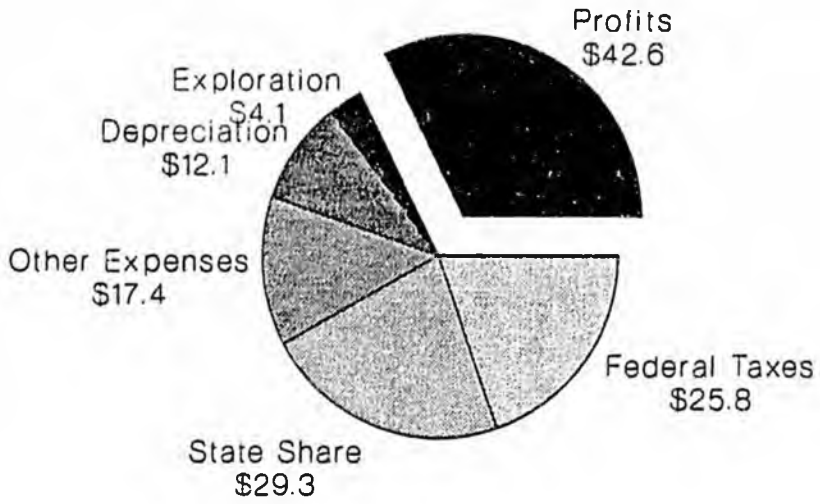
Table 1
Total Alaska Oil Profit
1969 through 1987
(billions of dollars)

Revenues:		
Production revenue	$ 97.6	
TAPS revenue	33.7	
Total Revenues		**$131.3**
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		88.7
Profit		**$ 42.6 Billion**

Profit per barrel: $6.59

Figure 1 graphs the relationship among the revenues, expenses and profit for all Alaska oil production and transportation activities.

Figure 1
Revenues, Expenses and Profit
All Alaska Oil Activities
(billions of dollars)



The $42.6 billion in profit is what the producers received after accounting for all expenses, including exploration, lease acquisition, and after allowing recovery of the costs of investments in Alaska oil activities related to the useful lives of the investments.[1]

From 1977 through 1987, virtually all of these profits were earned from the Alaska North Slope (ANS). ANS production contributed $29.1 billion to profit, with $27.8 billion of this amount attributable to Prudhoe Bay. Total production profit for the Prudhoe Bay field is given in Table 2.

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[1]Details of how the profit estimates were obtained are provided in the technical discussion. Some of the amounts could not be readily determined from publicly available data or the data were ambiguous. In these situations, a conservative approach was taken. As a result, this report gives a low-end estimate of oil industry profits. Throughout this report, the sum of the individual numbers may not add to identical totals due to rounding.

Table 2
Total Prudhoe Bay Production Profit
1977 through 1987
(billions of dollars)

Production Revenue	$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Taxes	5.9
Federal Income Taxes	13.0
Profit	**$ 27.8 Billion**

Profit per barrel: $5.81

Figure 2 shows the division of these revenues, expenses and profit.

Figure 2
Revenues, Expenses and Profit
Prudhoe Bay Production
(billions of dollars)

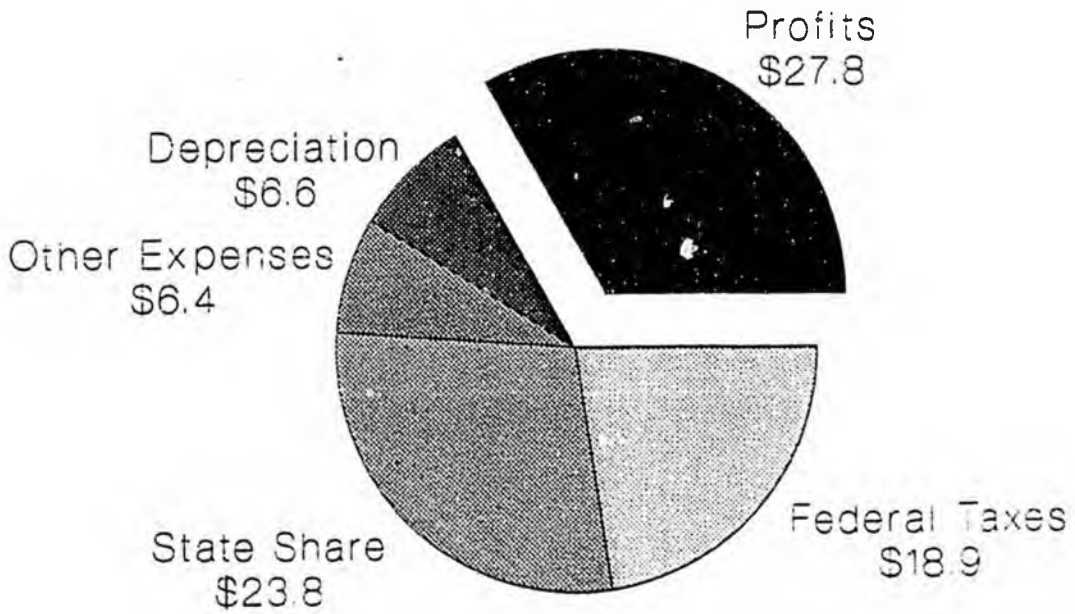


Table 3 shows Prudhoe Bay production profit for the oil producers on a year-by-year basis from 1977 through 1987.

Table 3
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$6,573	$4,327	$9,847	$10,097	$10,079
Expenses:					
Depreciation	1,074	1,110	873	710	632
Operating Expenses	740	514	535	578	394
Overhead	109	104	139	89	93
Interest	146	139	141	119	119
Royalty	787	518	1,179	1,209	1,207
Severance Taxes	787	571	1,300	1,333	1,331
Property Taxes	150	148	150	148	147
State Income Taxes	83	37	165	171	172
Windfall Profit Taxes			39	211	426
Federal Income Taxes	917	0	2,212	1,469	1,756
Profit	**$1,780**	**$1,186**	**$3,114**	**$4,061**	**$3,801**
Profit per barrel:	**$3.55**	**$2.40**	**$6.25**	**$8.26**	**$7.75**

1977 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*	*1977*
Revenue	$11,271	$13,330	$9,541	$5,892	$1,849	$ 717
Expenses:						
Depreciation	581	510	476	320	254	38
Operating Expenses	504	546	182	184	157	46
Overhead	77	51	15	2	0	2
Interest	139	17	10	156	203	117
Royalty	1,350	1,596	1,143	706	221	86
Severance Taxes	1,488	1,291	924	622	195	76
Property Taxes	147	146	146	123	104	30
State Income Taxes	168	669	550	367	67	30
Windfall Profit Taxes	1,375	3,089	797			
Federal Income Taxes	2,125	1,971	2,086	383	9	32
Profit	**$3,315**	**$3,443**	**$3,212**	**$3,030**	**$ 639**	**$ 260**
Profit per barrel:	**$6.78**	**$7.09**	**$6.61**	**$7.39**	**$1.84**	**$2.58**

The Kuparuk field is the second major source of production profit on the ANS. Total producer profit after taxes from this field are shown in Table 4.

Table 4
Total Kuparuk Production Profit
1982 through 1987
(billions of dollars)

Production Revenue	$ 5.1
Less Expenses:	
Depreciation	1.0
Operating Expenses	.7
Overhead	.1
Interest	.2
Royalty	.5
Severance Taxes	.4
Property Taxes	.2
State Income Taxes	.1
Federal Income Taxes	.6
Profit	**$ 1.3 Billion**
Profit per barrel: $3.66	

Annual Kuparuk profits are shown in Table 5.

Table 5
Kuparuk Production Profit
(millions of dollars)

	1987	*1986*	*1985*	*1984*	*1983*	*1982*
Production Revenue	$1,055	$ 644	$1,282	$ 767	$ 707	$ 591
Expenses:						
Depreciation	263	254	204	117	112	83
Operating Expenses	174	110	125	100	77	78
Overhead	20	20	25	11	11	7
Interest	32	32	33	20	21	20
Royalty	113	69	137	82	76	63
Severance Taxes	85	52	103	62	57	48
Property Taxes	44	41	35	20	17	14
State Income Taxes	10	2	19	11	10	8
Federal Income Taxes	105	0	247	91	102	104
Profit	**$ 207**	**$ 65**	**$ 351**	**$ 254**	**$ 222**	**$ 165**
Profit per barrel:	**$2.31**	**$.79**	**$5.04**	**$6.28**	**$6.37**	**$5.80**

Total revenues, costs and profit from Alaska production activities from 1969 to the end of 1987 are given in Table 6.

Table 6
Total Alaska Production Profit
1969 through 1987
(billions of dollars)

Production Revenue	$ 97.6
Less Expenses:	
Depreciation	8.1
Operating Expenses	5.3
Exploration Expenses	4.1
Overhead	.8
Interest	1.7
Royalty	11.8
Severance Taxes	10.4
Property Taxes	1.8
State Income Taxes	2.7
Windfall Profit Taxes	6.4
Federal Income Taxes	14.3
Profit	**$ 30.2 Billion**

Profit per barrel: $4.96

A graph showing the distribution of these revenues, expenses and profit is shown in Figure 3.

Figure 3
Revenues, Expenses and Profit
All Alaska Production
(billions of dollars)

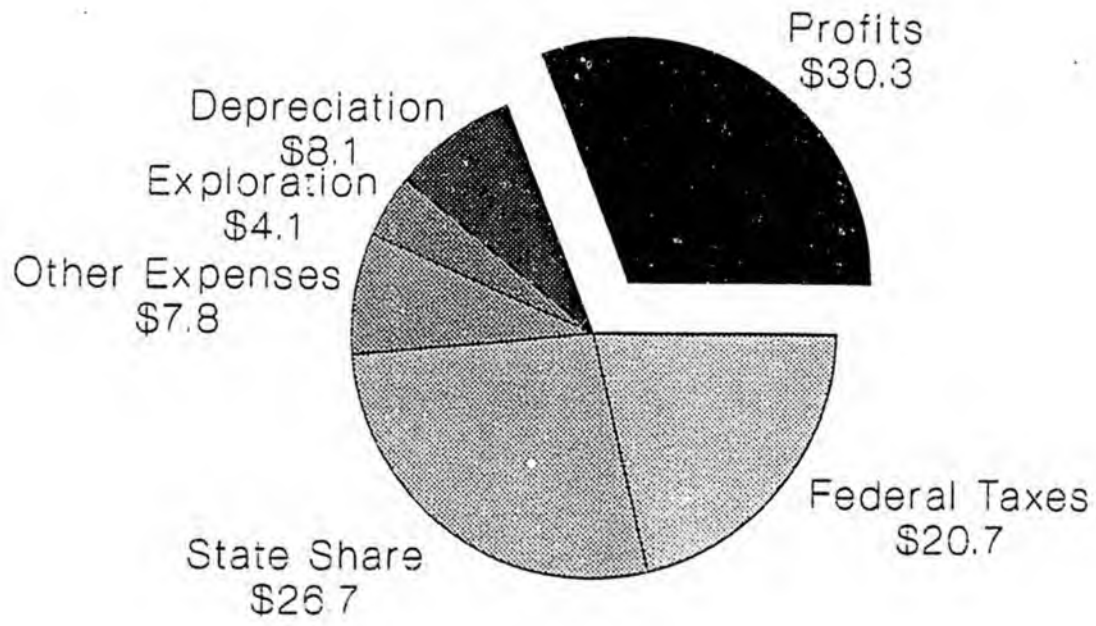


Table 7 shows the annual profits received from production activities in Alaska from 1969 through 1987.

Table 7
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$8,046	$5,367	$11,735	$11,592	$11,564
Depreciation	1,394	1,418	1,123	866	779
Operating Expenses	940	653	679	678	500
Exploration Expenses	288	288	514	258	818
Overhead	139	133	173	106	111
Interest	192	183	183	148	150
Royalty	970	647	1,414	1,397	1,393
Severance Taxes	871	623	1,403	1,395	1,388
Property Taxes	197	192	188	172	159
State Income Taxes	92	37	182	189	174
Windfall Profit Taxes			39	235	475
Federal Income Taxes	1,007	0	2,424	1,627	1774
Profit	**$1,956**	**$1,192**	**$3,413**	**$4,521**	**$3,841**
Profit per barrel:	**$3.18**	**$2.01**	**$5.83**	**$8.15**	**$6.97**

1978 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenue	$12,785	$14,484	$9,961	$6,321	$2,254
Expenses:					
Depreciation	698	540	504	345	280
Operating Expenses	506	571	183	188	176
Exploration Expenses	647	419	176	174	274
Overhead	91	55	16	2	a
Interest	171	18	10	167	247
Royalty	1,641	1,745	1,198	762	272
Severance Taxes	1,536	1,291	923	622	195
Property Taxes	165	151	152	130	113
State Income Taxes	175	702	556	369	66
Windfall Profit Taxes	1,491	3,314	861		
Federal Income Taxes	2,212	2,067	2,110	399	8
Profit	**$3,452**	**$3,610**	**$3,270**	**$3,161**	**$ 623**
Profit per barrel:	**$6.33**	**$6.96**	**$6.21**	**$6.97**	**$1.56**

Table 7 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

	1977	*1976*	*1975*	*1974*	*1973*
Revenue	$ 1,054	$ 380	$ 396	$ 372	$ 377
Expenses:					
Depreciation	53	16	16	16	16
Operating Expenses	64	16	15	10	3
Exploration Expenses	25	25	25	25	25
Overhead	3	a	a	a	a
Interest	177	1	1	a	a
Royalty	131	46	48	45	45
Severance Taxes	76	28	27	15	15
Property Taxes	31	12	13	13	13
State Income Taxes	49	23	24	24	24
Federal Income Taxes	52	85	91	89	89
Profit	**$ 394**	**$ 133**	**$ 142**	**$ 140**	**$ 140**
Profit per barrel:	**$2.49**	**$1.94**	**$1.94**	**$1.89**	**$1.33**

1969 - 1972:

	1972	*1971*	*1970*	*1969*
Revenue	$ 283	$ 279	$ 278	$ 227
Expenses:				
Depreciation	16	16	17	14
Operating Expenses	3	2	1	1
Exploration Expenses	25	25	25	25
Overhead	a	a	a	a
Interest	a	a	a	a
Royalty	34	34	34	27
Severance Taxes	12	11	8	6
Property Taxes	13	10	14	13
State Income Taxes	17	17	17	13
Federal Income Taxes	63	63	64	50
Profit	**$ 99**	**$ 98**	**$ 100**	**$ 79**
Profit per barrel:	**$1.23**	**$1.22**	**$1.17**	**$1.04**

a. Less than $1 million.

TAPS PROFIT

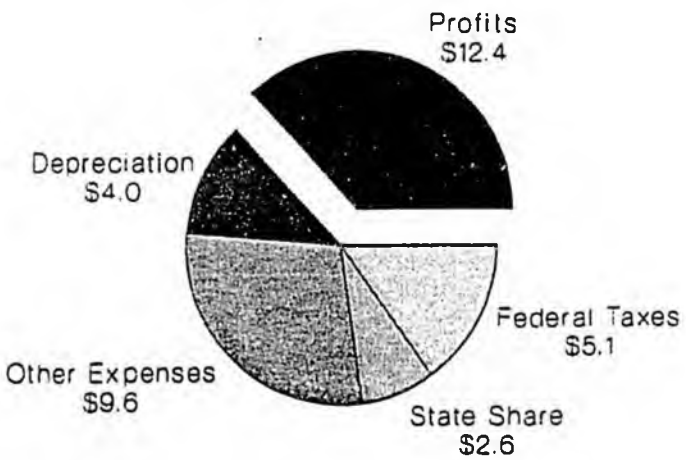
The Trans-Alaska Pipeline System (TAPS) is owned by the Prudhoe Bay producers in approximately the same proportion as their ownership interest in the Prudhoe Bay field. Profit from TAPS, therefore, accrues to the same producers. Table 8 shows the overall revenues, expenses and profit for TAPS from 1978 through 1987.[2]

Table 8
Total Estimated TAPS Profit
(billions of dollars)

Revenue	$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
State Income Taxes	.9
Federal Income Taxes	5.1
Profit	**$12.4 Billion**
Profit per barrel: $2.41	

The distribution of these items are shown in Figure 4.

Figure 4
TAPS Revenues, Costs and Profit
(billions of dollars)



[2]The one-half year of activity during 1977 when TAPS started does not have a significant effect on the results. Data from that year are unavailable.

A year-by-year comparison of TAPS profit is shown in Table 9.

Table 9
Annual TAPS Profit
(millions of dollars)

1983 through 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Revenue	$2,765	$3,080	$3,578	$3,926	$3,899
Expenses:					
Depreciation	299	310	309	431	475
Operating and Administrative	255	343	247	387	483
Interest	150	440	411	570	579
Property Taxes	147	164	168	171	165
State Income Taxes	57	55	73	71	66
Federal Income Taxes	631	0	984	610	674
Profit	**$1,226**	**$1,768**	**$1,386**	**$1,686**	**$1,457**
Profit per barrel:	**$2.08**	**$3.07**	**$2.44**	**$3.17**	**$2.77**

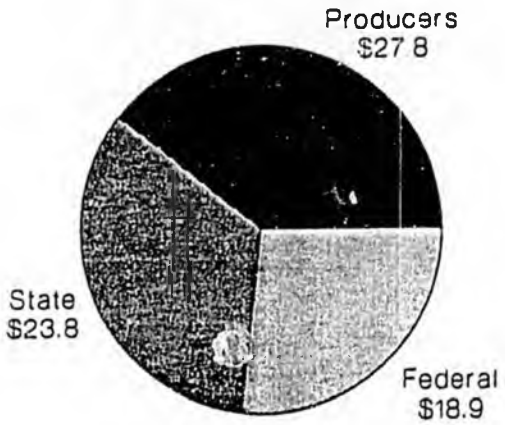
1978 to 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenue	$3,896	$3,605	$3,554	$2,963	$2,394
Expenses:					
Depreciation	467	431	503	421	355
Operating and Administrative	498	474	435	330	381
Interest	648	681	720	771	846
Property Taxes	168	171	168	174	174
State Income Taxes	63	203	162	119	60
Federal Income Taxes	802	599	617	129	8
Profit	**$1,250**	**$1,046**	**$ 949**	**$1,019**	**$ 570**
Profit per barrel:	**$2.42**	**$2.15**	**$1.95**	**$2.49**	**$1.64**

SHARES

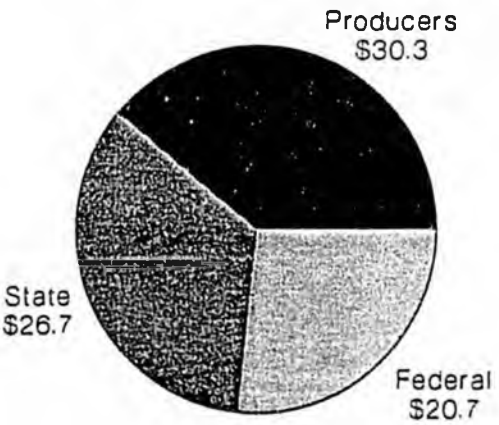
At the super-giant Prudhoe Bay field, producers earned $27.8 billion. The State received $23.8 billion from Prudhoe Bay and the Federal government received $18.9 billion. This is shown visually in Figure 5. The nearby giant Kuparuk field added $1.3 billion to producer profit, $1.2 to the state and $0.6 billion to the Federal government's revenues.

Figure 5
Shares
Prudhoe Bay Production
(billions of dollars)



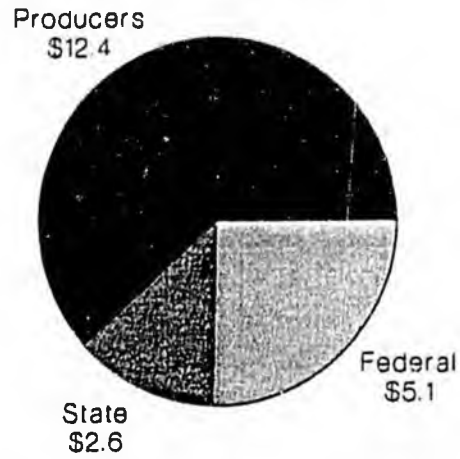
The sharing from all production in Alaska between 1969 and 1987 is shown in Figure 6, with $30.3 billion to the producers, $26.7 billion to the State and $20.7 billion to the Federal government.

Figure 6
Shares
All Alaska Production
(billions of dollars)



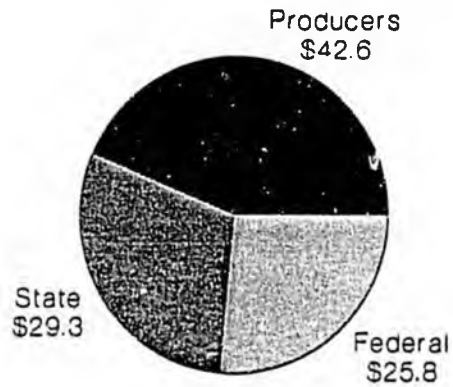
TAPS profit of $12.4 billion went to the producers, $2.6 billion went to the State through property and income taxes and $5.1 billion went to the Federal government through income taxes. This distribution is shown in Figure 7.

Figure 7
TAPS Shares
(billions of dollars)



A summary of the distribution for all Alaska oil operations is shown in Figure 8. The $42.6 billion in after-tax profit that accrued to the oil producers compares to $29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were $25.8 billion from these activities. Figure 8 shows the relationship between industry profit and the state and federal receipts from oil industry revenues.

Figure 8
Shares
All Alaska Production and Transportation
(billions of dollars)



ADDITIONAL BENEFITS OF ANS OIL

ANS producers receive profits from Alaska oil outside of Alaska which provides an additional bonus beyond what it would cost if they had to purchase imported oil. An additional profit of approximately $0.7 billion went to the producers through the operation of the U.S. Department of Energy crude oil entitlements program. Producers are believed to earn additional profit through the refining of ANS crude because, among other things, they have access to a secure source of crude oil. If they did not have the ANS crude, it would be necessary for them to acquire crude from foreign sources.

Others estimate that profits on tanker operations and trans-Panama shipment activities added between $.25 and $1.00 profit per barrel of ANS crude produced. These additional profits would have been received on the nearly 6 billion barrels of ANS production. These added profits are not included in the $42.6 billion of total oil industry profit in Alaska covered in this report.

INVESTMENTS MADE ON THE ALASKA NORTH SLOPE

Figure 9 shows the relative amounts of money invested in projects to produce ANS crude. The greatest investment was $9.4 billion in TAPS. The total investment to date in Prudhoe Bay was $8.7 billion. This includes the waterflood project and the miscible gas injection project as well as infield drilling. The investment in Kuparuk was $4.3 billion which includes amounts for the newly installed waterflood project that had not been in operation during the period of this study. Milne Point cost $575 million. Endicott and Lisburne each cost approximately one billion dollars. As of the end of 1987, Milne Point had been shut in, while Endicott and Lisburne had just begun operations too recently to have a significant impact on the revenue numbers reported here. The investments made in Cook Inlet during this period were not significant relative to the ANS investments during this period.

Figure 9
ANS Investments
(billions of dollars)

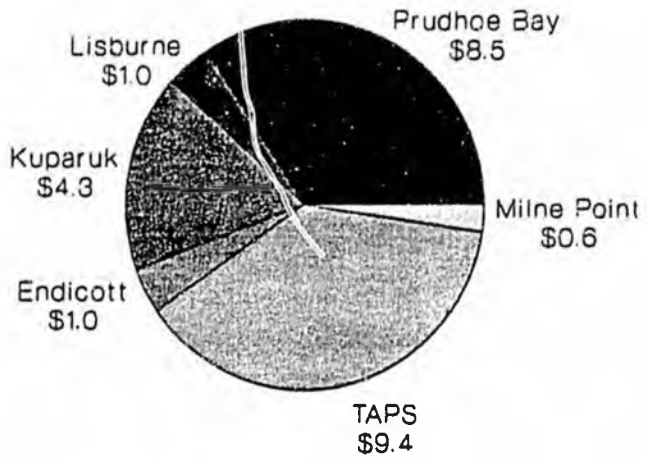


Table 10 shows the timing of the investments in Prudhoe Bay and other ANS projects together with an estimate of the timing of the investment in TAPS. These investment timings are based on information from the producers and may not be exact.

Table 10
ANS Investments
(millions of dollars)

Year	*Project*	*Amount*
1987	Prudhoe gas	$ 720
1987	Kuparuk waterflood	900
1987	Endicott	1,000
1986	Lisburne	1,000
1985	Prudhoe gas plant	720
1984	Milne Point	570
1983	Prudhoe waterflood	2,000
1981	Kuparuk	3,400
1981	Prudhoe drilling	1,100
1980	Prudhoe drilling	250
1979	Prudhoe drilling	250
1977	Prudhoe*	1,850
1977	TAPS*	4,700
1976	Prudhoe*	1,850
1976	TAPS*	4,700
Total		**$ 25,015**

*These amounts were spent over the period 1969 through 1977, with the majority of the funds spent later in the construction phaso of the project.

Cash flows can be related to these investments to compute a rate of return on the investment in Alaska. Assuming the entire investment was made with equity funds, cash flows are deemed equal to profit plus depreciation and interest. A schedule of these "all-equity" cash flows is shown in Table 11.

Table 11
All-Equity Cash Flows
(millions of dollars)

		---Cash Flows---		Net
Year	*Investment*	*Production*	*TAPS*	*Cash Flow*
1987	2,620	3,542	1,675	2,597
1986	1,000	2,793	2,518	4,311
1985	720	4,719	2,106	6,105
1984	570	5,512	2,687	7,629
1983	2,000	4,770	2,511	5,281
1982	0	4,321	2,365	6,686
1981	4,500	4,168	2,158	1,826
1980	250	3,764	2,172	5,686
1979	250	3,673	2,211	5,634
1978	0	1,151	1,771	2,922
1977	6,550	655	0	-5,895
1976	6,550	0	0	-6,550

The equivalent rate of return earned on this stream of cash flows after tax is 29.7%.

As it happened, a substantial portion of the investment was financed with borrowed monies. The 1978 Sohio annual report to shareholders indicated that 75% of the company's funds were from debt. In this case, the investments in 1976 and 1977 as shown in Table 11 would be $1,638 net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data in Table 12 is the profit plus depreciation. These cash flows include a deduction for interest expense. Assuming that all of the cash flows were used to pay of the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978

through 1979 and all but $2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table 12.[3]

Table 12
Cash Flows with 75% Borrowing
(millions of dollars)

		-----Cash Flow-----		*Net Cash*
	Investment	*Production*	*TAPS*	*Flow*
1987	2,620	3,350	1,525	2,255
1986	1,000	2,610	2,078	3,688
1985	720	4,536	1,695	5,511
1984	570	5,364	2,117	6,911
1983	2,000	4,620	1,932	4,552
1982	0	4,150	1,717	5,867
1981	4,500	4,150	1,477	1,127
1980	250	3,754	1,452	2,131
1979	250	3,506	1,440	0
1978	0	903	925	0
1977	6,550	478	0	-1,160
1976	6,550	0	0	-1,637

The rate of return implied from the stream of cash flows shown in Table 12 is 43.7%.

REINVESTMENT OF ALASKA PROFIT

A question of importance to Alaska is what happens to the profit earned from oil activities in Alaska. It has been necessary for the industry to make certain investments to maximize production from the Prudhoe Bay field. Initial investments are shown in 1976 and 1977 in Table 10. Reinvestments are shown in Table 10 for the years 1978 through 1987. In addition, the industry has reinvested through exploration.

Reinvestments shown in Table 10 are added to exploration expenses to obtain total reinvestments for the period 1978 through 1987. These reinvestments are shown in the first column of Table 13. For the years 1978

---

[3]Loan repayments took place over a longer time period, but it is not feasible within this project to determine actual repayment dates for ANS investment-related debt. This model assumes earlier repayment, but also includes the later interest costs reported by the producers. The net effect of this is to understate the rate of return.

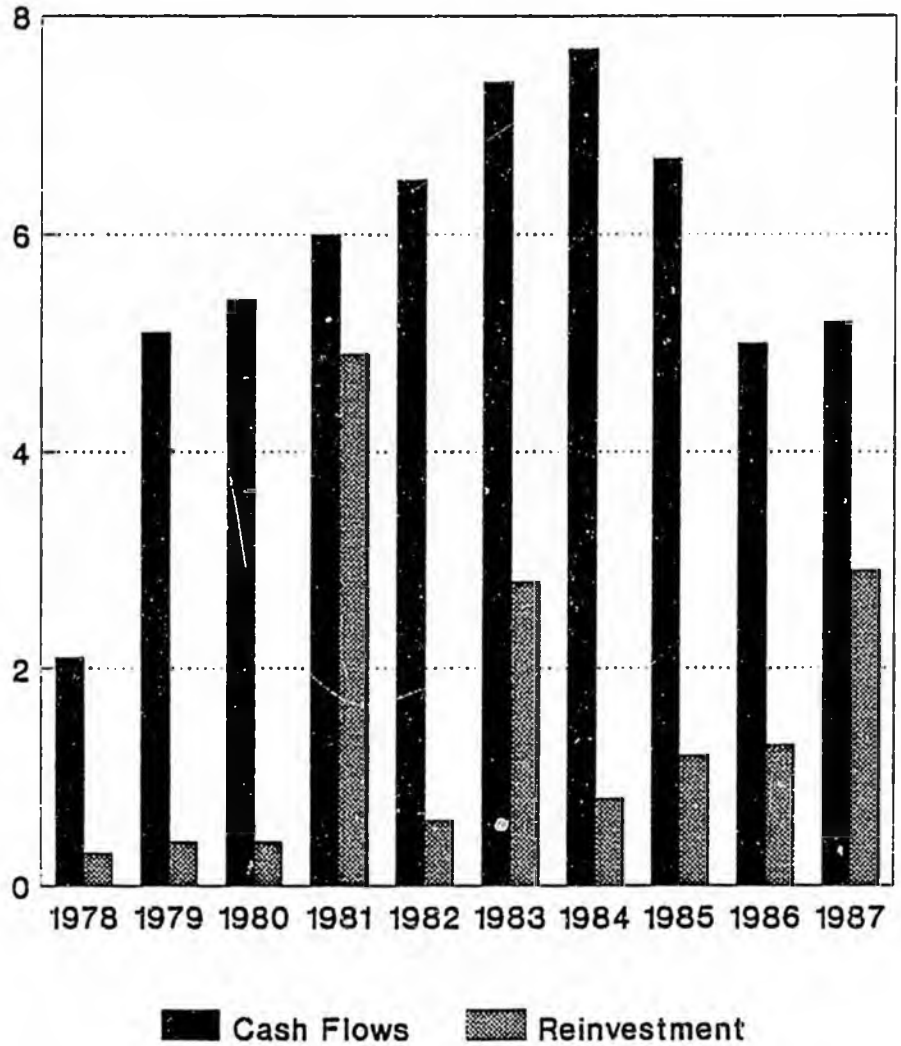
through 1987, these reinvestments are compared to cash flows received from Alaska oil operations. These cash flows are equal to profit plus depreciation and exploration expenses. They are shown as the third and fourth columns in Table 13. Each year's ratio of reinvestment to cash flows is shown in the last column of Table 13.

Table 13
Reinvestment and Reinvestment Flows
(millions of dollars)

	Re-	*----Cash Flows----*			*Reinvestment*
Year	*investment*	*Production*	*TAPS*	*Total*	*Ratio*
1987	2,908	3,638	1,525	5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%

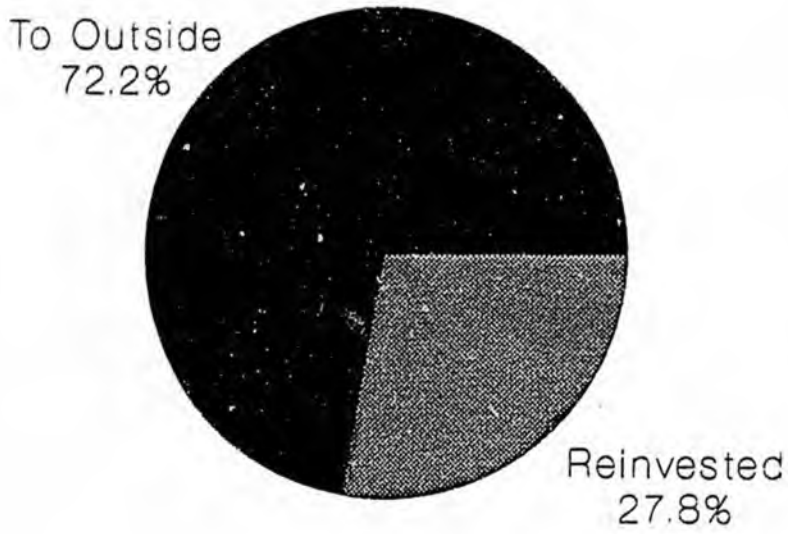
Table 13 indicates that 27.8% of the cash flows from oil and gas industry activities in Alaska was reinvested in Alaska. The reinvestment is shown graphically in Figure 10.

Figure 10
Reinvestment in Alaska by Years
(billions of dollars)



The relationship between the percentage of funds reinvested in Alaska oil projects and those which flow outside is shown in Figure 11.

Figure 11
Overall Reinvestment of Oil Industry Flows
(percentage)



HOURLY PROFIT RATE

Looking at these profits as an hourly earnings number may bring the amounts into better perspective. After-tax profits have been earned by the producers at the rate of $463,144 per hour, twenty-four hours per day for each day of the first ten and one-half years of ANS production.

SENSITIVITY OF ESTIMATES

Where possible, the different assumptions used to develop these profit estimates were studied in more detail to see how sensitive the profit estimates were to the different assumptions. When in doubt, a conservative approach was taken. A total of $7.5 billion in potential profit increases related to assumptions

that were resolved in favor of conservatism was ignored. By contrast, a total of $.6 billion in potential profit decreases related to assumptions were also ignored.

After considering the impact of all potential adjustments due to the assumptions used in the report, the range of profit estimates runs from a minimum of $41 billion to a maximum of $47 billion. The $42.6 billion reported here is at the low end of this range.

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Oil Industry Profitability in Alaska

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TECHNICAL DISCUSSION

Oil Industry Profitability in Alaska 1969 through 1987

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Technical Discussion

The profit estimates reported in this report were developed from publicly available information about oil industry activities in Alaska. Although a substantial amount of information exists about oil industry activities in Alaska, a complete picture of profit from Alaska activities is not published in any known reference. Assembling a report on oil industry profit requires gathering information from a number of different sources, piecing together an overall picture of profit and cross-checking the estimate obtained in this manner with other data sources. In the end, the profit estimate should be quite close to the actual results.

Throughout this report the terms "approximate" and "estimate" appear quite frequently. These terms are necessary because public data do not exist which would enable one to compute Alaska profit precisely. The approach taken here, when there are questions about amounts, is to take the conservative approach. The profit reported then will represent the low end of the range. This section of the report provides details on how the pieces of the puzzle were assembled and how the resulting profit estimates were cross checked. After all of this, some questions still remain. The effect of these remaining questions is covered in Section III of this technical discussion.

APPROACH TO MEASURING ALASKA OIL COMPANY PROFIT

In its most fundamental form, profit is the amount that is left over from revenues after paying all expenses including income taxes and an allowance for the cost of the initial investment. In accounting terms, estimation of profit becomes more complex because accountants must relate revenues to expenses that occur in different times. Accounting profits therefore are based on an

analysis of transactions that took place in the past with appropriate adjustments to determine the profit attributable to a specific period of time. In this report, profit from Alaska oil industry activities are estimated over the period 1969 through 1987.[1]

Alaska oil producers earn profit from the production, transportation and sale of crude oil. The primary sources of these profits are production from Prudhoe Bay field on the Alaska North Slope (ANS) and TAPS.

A company engaged in Alaska oil activities can estimate its own profit rather readily by extracting transaction data from its own books and by making appropriate adjustments. To make such an estimate from the outside is much more complex because a significant portion of company data is kept private. Hence, it is necessary to identify that information which is public and piece together a picture of the profitability of Alaska oil operations. This task requires obtaining as much information as possible and then making assumptions about the missing data and, where possible, cross-checking the results with other public data sources. This is the process followed to develop the profit estimates reported here.

For example, Standard Oil Company of Ohio (formerly Sohio, now BP America) includes a section in its corporate annual report that states its profit from Alaska oil production operations. (See Appendix A for an example of this disclosure.) If every other producer obtained the same revenues per barrel of crude oil and incurred the same costs to produce that oil, one could project from the Sohio data to all Alaska production. However, this approach cannot be used because it is widely known that Sohio sells most of its ANS crude on the U.S. Gulf Coast whereas other producers sell their crude oil on the U.S. West Coast.

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[1]See Financial Accounting Standards Board, *Statement of Financial Accounting Concepts No. 3*, Pars. 12 and 56 - 62 for a comprehensive discussion of profit concepts.

Prices in the two markets differ. According to Barclay's de Zoete Wedd (1988), U.S. West Coast prices are about $1 lower than the Gulf Coast, but it costs about $2.45 more to ship a barrel of crude oil to the Gulf Coast. To obtain revenues for all producers, it is necessary to adjust Sohio revenues by taking account of the differences in crude oil values. This is one of the many adjustments necessary to obtain an estimate of profit.

The more assumptions that need to be made, the more questions that will arise about the profit number that is obtained. However, there are alternate sources of information that can be used to compare a significant portion of the data used to compute profit. To the extent that these alternate sources are consistent, the computed profits will be more reliable. The most important item in the profit equation is revenue. Fortunately, estimates of producers can be checked against Alaska severance tax collections. For most of the period covered by this report, the Alaska severance tax is stated as 15% of the value of producers' production, subject to certain adjustments. This implies that for production subject to the 15% rate, an amount equal to 15% of production revenue should approximate the reported severance tax collections by the State of Alaska. Similar comparisons can be made for production subject to other severance tax rates.

In addition, the estimate included in this report is not the only estimate of oil industry profit in Alaska. Financial analysts and others have, from time to time, estimated profit from Alaska oil industry activities. (See Appendices B and C for examples.) The numbers reported here have been checked, to the extent possible, with other data sources.

Not all of the numbers can be checked and many of the alternate information sources use different bases for reporting their data. The last part of section III of

this report discusses the effects that substantial questions raised by the estimation process are likely to have on the total estimated profit. As noted in this report, most of the effects are quite small. This is an unavoidable problem. Indeed, it is very likely that producers are unable to estimate their own profits down to the last cent because of the assumptions that they make in developing their profit numbers. The point is that the estimate developed here is, on balance, consistent with other estimates of profits earned in Alaska. Indeed, the total effect of questions about alternate treatments is that the profit reported here is on the conservative side. One may perhaps argue that total profit is $2 billion higher or lower than this estimate, but such a debate should not detract from the validity of the overall picture presented here.

The first part of this report develops estimated revenues from production activities, essentially the gross receipts from operations. This report focuses on the revenues that accrue to the producers, net of royalty. This is defined as "working interest revenue." To calculate working interest revenue, it is necessary to know production and the value of each barrel of production. Those matters are discussed in Section I under "Production Revenues".

Section II covers the expenses that must be deducted from revenues to obtain profit for this project. These expenses include depreciation, severance taxes, operating expenses, windfall profit taxes, exploration expenses, overhead and interest. Each of these items is discussed in turn. Both the State of Alaska and the U.S. government levy taxes on income as defined in their laws. These are expenses for accounting purposes and are also presented in Section II. Royalties are eliminated from revenues reported by oil and gas producers. In Section III, royalties are included as a separate line item to determine both the working interest (producers') revenues and total revenues.

The third section of the report gives the detailed statements of profit for Prudhoe Bay, Kuparuk and all Alaska production. This section also includes a discussion of the sensitivity of the profit estimates to cost estimates, missing data, various allocations, and other factors on the profit estimates.

The fourth section of the report shows the profit earned from TAPS. Here it is reasonable to rely extensively on Sohio Pipeline Company's disclosures. Other data sources generally confirm the Sohio Pipeline information.

Each part of this technical discussion is designed to provide further detail about the way the data presented in the report was developed. To the extent possible, the report follows accounting practices and conventions that enable one to obtain a reasonable estimate of the profitability of Alaska's oil industry activities. The resulting estimates give an accurate, although not exact, picture of the profitability of Alaska's oil industry operations.

Profit has been estimated for Prudhoe Bay, Kuparuk, all Alaska production and TAPS. After making all of the calculations and cross-checking available data, total oil industry profit in Alaska is estimated as $42.6 billion. This includes $27.8 billion from Prudhoe Bay, $1.3 billion from Kuparuk and $12.4 billion from TAPS. An additional $1.1 billion was earned elsewhere in Alaska.

After looking at the effects of all of the estimates made on reported profit, a range within which the actual number is likely to fall can be developed. The low end of this range is $41 billion and the high end is $47 billion. The estimated profit of $42.6 billion reported here is in the low end of this conservative estimated range.

Finally, reported profit is based on public information which was available at the time this report was written. It is entirely possible that data not available

could affect the analysis. Any such data would be welcomed to advance the goal of obtaining a more precise estimate of Alaska oil industry profit.

I. PRODUCTION REVENUES

PRODUCTION ESTIMATES

Production estimates for crude oil and natural gas were obtained from different data sources and compared. Since the foundation of reported profit depends on production estimates, it is important to note how the estimates compare. Moreover, each company's reported accounting data are based on its production estimates. Thus, the production data are needed for making certain computations from company reports. The estimates for crude oil are discussed first in this section, followed by the estimates for natural gas.

Crude Oil. Production estimates were obtained from the corporate annual reports of Arco, Sohio and BP America, the Alaska Oil and Gas Conservation Commission Statistical Series, DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1987) and the *International Petroleum Encyclopedia*, as well as from the *U.S. Energy Statistics Sourcebook* (1988). As shown below, the estimates provided by each of these sources differ with respect to the time periods covered, the level of detail and the volumes of production.

The producers' corporate annual reports present production information in terms of barrels per day of production. The data as reported by each company are shown in Table I-1.

Arco presented separate information on the production from Prudhoe Bay, Kuparuk and Lisburne for the years 1980 through 1987. From 1978 on, Sohio/BP presented data for all of its Alaska operations. Prior to 1982, virtually all of Sohio/BP's production was from the Prudhoe Bay field. These data facilitated obtaining production estimates for each of those fields.

Table I-1
Company Net Production Data
(000 barrels per day)

	-------Arco Reports-------			
Year	*Prudhoe*	*Kuparuk*	*Lisburne*	*Sohio/BP*
1987	324.9	122.0	15.0	827.2*
1986	306.9	109.9	4.1	706.4#
1985	304.9	94.9	8.5	699.7
1984	326.1	71.7	8.9	617.9
1983	336.4	69.9	10.0	594.8
1982	292.4	61.8	na	676.6
1981	275.5	2.1	na	698.2
1980	274.7			696.4
1979	248.6**			590.8
1978	213.3**			506.8
1977	213.3**			143.8
1976	78.4**			
1975	27.9**			

* BP America data.
# Sohio data. BP America reported 781.4 thousand barrels per day.
** Arco's total Alaska production.

The data reported in Table I-1 were converted to an annual number by multiplying the daily figures by 365. The company statistics were then divided by the company's proportionate share in production to arrive at an estimate of total production based on each company estimate. Adjustments were made for the 1982 redetermination of each company's Prudhoe Bay share of production. The estimates of total Prudhoe Bay production based on Arco's and Sohio/BP's corporate disclosures are in the first two columns of Table I-2, below. The estimates of total Kuparuk production based on Arco's corporate disclosures are in the first column of Table I-3, below. The corporate disclosures give the company's working interest production (net of royalty).

The Alaska Oil and Gas Conservation Commission provides gross production by field for all years covered by this study. The *International Petroleum Encyclopedia* reports gross production from major fields by year. However, the *Encyclopedia* is not complete. In certain years it does not show all fields.

The DeGolyer and MacNaughton statistics are based on the U.S. Department of Energy reports and show gross production from Alaska. They do not show production from specific fields.

The *U.S. Energy Statistics Sourcebook* data show total ANS production for 1981 through 1987 and total Alaska production for prior years. An assumed 1/8 royalty interest was deducted from this number to arrive at an estimate of ANS working interest production. Production from Kuparuk and Lisburne (based on Arco's disclosures) were deducted to arrive at an estimate of Prudhoe Bay production. These data are in Column 3 of Table I-2.

The estimates presented under each method differed. To test the different estimates for reasonableness, TAPS and Kuparuk pipeline throughputs were analyzed. This analysis is based on the assumption that all of Kuparuk production (including royalty oil) should equal the Kuparuk pipeline throughput. TAPS throughput should be comprised of Kuparuk, Lisburne, and Prudhoe Bay crude, including royalty oil. Deducting Kuparuk, Lisburne and Prudhoe Bay royalty oil should give the working interest production from Prudhoe Bay.

Annual total TAPS throughput for 1982 through 1987 was obtained from the Arco annual report. Similar data for 1980 to 1981 were obtained from the Sohio report. Royalty interests as well as Lisburne and Kuparuk production were deducted from total TAPS throughput to obtain an estimate of Prudhoe Bay production. The results of this analysis are shown in Column 5 of Table I-2.

In addition to these estimates, data on total production from Prudhoe Bay, including royalty, were presented in the *International Petroleum Encyclopedia*. These data were available for 1983, 1984, 1985, and 1987. Royalty of 1/8 was deducted from gross production to obtain another estimate of Prudhoe Bay working interest production for comparison purposes.

The sources that provided reasonably complete data series included Arco, Sohio/BP, the *U.S. Energy Statistics Sourcebook*, the Alaska Oil and Gas Conservation Commission statistics and the analysis of pipeline throughput. The estimated working interest production from Prudhoe Bay based on each of these different estimates is shown in Table I-2. After reviewing the data and the different levels of complexity required for each alternate estimate, it appears that the Alaska Oil and Gas Conservation Commission (AOGCC) statistics provided a reasonable, conservative and consistent data series over the period covered by this report.

Table I-2
Annual Production Estimates: Prudhoe Bay
Net of Royalty
(000,000 barrels per year)

Year	*Arco*	*Sohio/BP*	*U.S. Energy Data Sourcebook*	*AOGCC Statistics*	*Pipeline Throughput Analysis*
1987	544.5	592.0	507.3	500.8	520.9
1986	500.1	508.8	493.6	494.5	493.8
1985	496.8	503.9	497.8	498.5	497.3
1984	531.4	467.5	492.1	491.9	489.6
1983	547.4	458.6	487.3	490.8	486.1
1982	492.7	490.0	489.2	489.2	488.4
1981	493.4	480.8	486.7	485.8	495.0
1980	527.7	479.6	517.7	486.0	479.1
1979	na	406.9	447.4	409.9	na
1978	na	349.0	392.5	348.0	na
1977	na	99.1	148.1	100.9	na

For 1977 through 1986, production estimates used for computing Prudhoe Bay profit are based on the AOGCC statistics shown in Table I-2. The 1987 estimate used the AOGCC estimate for Prudhoe Bay plus Arco's estimate for Lisburne. The production number chosen was neither the highest nor the lowest for all years. It is generally believed that the AOGCC estimates are reliable and acceptable estimates of field production.

Kuparuk production estimates are based on 7/8 of Kuparuk pipeline throughput as reported by Arco. The 7/8 number reflects the net working interest

production. The *International Petroleum Encyclopedia* also reported estimated production from Kuparuk. The *International Petroleum Encyclopedia* data were adjusted to reflect a 1/8 royalty interest. The AOGCC reported Kuparuk production was adjusted to reflect a 1/8 royalty interest also. These different annual working interest production estimates for Kuparuk are reproduced in Table I-3.

Table I-3
Annual Production Estimates: Kuparuk
Net of Royalty
(000,000 barrels per year)

Year	*Arco*	*International Petroleum Encyclopedia*	*AOGCC Statistics*
1987	90.4	87.1	89.6
1986	87.2	na	82.2
1985	70.3	69.6	69.7
1984	40.2	32.6	40.4
1983	38.3	34.0	34.9
1982	28.4	na	28.6
1981	na	na	.1

The Arco data are slightly higher for most of the years of Kuparuk production. Since the differences are minor, the Arco production data were used for Kuparuk. The very small production from Milne Point and Endicott would be included with Kuparuk. However, the amounts are too small to affect the analysis.

Lisburne production was reported by Arco at 14.4 million barrels in 1987. The *International Petroleum Encyclopedia* and the AOGCC reported this production at 14.3 million barrels in 1987. This amount has been included with Prudhoe Bay production in subsequent analysis.

For 1981 through 1987 and for years prior to 1978, other Alaska production was reported separately in the *U.S. Energy Statistics Sourcebook*. These data were used for comparison for those periods. For 1978 through 1980, other Alaska production was estimated as the difference between total Alaska production as reported in the *U.S. Energy Statistics Sourcebook* and ANS

production as computed in the two tables above. The results gave significantly higher estimates of other Alaska production during those three years. It was not possible to ascertain the reasons for the difference between these data and the AOGCC data. The two series of working interest production estimates for non-ANS production reproduced in Table I-4.

Table I-4
Non-ANS Production Estimates
Net of Royalty
(millions of barrels)

Year	*AOGCC Statistics*	*U.S. Energy Statistics Sourcebook*
1987	14.3	14.1
1986	15.4	15.4
1985	14.8	14.8
1984	19.3	19.2
1983	21.7	21.7
1982	24.0	24.0
1981	27.1	27.2
1980	31.7	98.1
1979	37.5	91.4
1978	43.8	87.1
1977	49.1	61.4
1976	58.6	55.5
1975	63.0	61.1
1974	63.2	61.8
1973	64.0	63.3
1972	64.4	63.8
1971	69.0	70.0
1970	73.2	73.2
1969	65.0	64.7

The Alaska Oil and Gas Commission statistics were used for purposes of non-ANS production in this report. The differences between AOGCC and an approach based on the Energy Statistics Sourcebook appears significant only in the years 1977 through 1980. During that period, the AOGCC data appear more reliable because the significant increase in production indicated for 1978 - 1980 by the *U.S. Energy Statistics Sourcebook* cannot be confirmed from other sources. It appears that this increase is a statistical fluke. In other years the two

data series track one another closely. It is unlikely that the differences in other years would have any substantial effect on the results.

Natural Gas. Estimation of natural gas production was simplified because there were fewer data sources. BP/Sohio provided information about gas production in their annual reports. All of Sohio's gas production was on the North Slope, and most of that was produced from Prudhoe Bay for use in production operations. Estimates of natural gas production in column 1 of Table I-5 are based on these data. The *U.S. Energy Statistics Sourcebook* provided data on total Alaska natural gas production. This data series is gross of royalty. Adjusting the *U.S. Energy Statistics Sourcebook* data for a 1/8 royalty and deducting the Sohio-based estimate of ANS production gives an estimate of ANS natural gas working interest production and other Alaska natural gas working interest production. The non-ANS production data computed by this method are reported in column 3 of Table I-5. These estimates were compared with AOGCC data and with data reported by the U.S. Department of Energy. The differences were not significant.

Table I-5
Natural Gas Production Estimates
Net of Royalty
(billions of cubic feet)

Year	*ANS per BP/Sohio*	*All Alaska per Sourcebook*	*Non-ANS Estimate*
1987	80.1	314.8	234.6
1986	70.4	266.7	196.4
1985	55.5	281.2	225.6
1984	41.8	253.0	211.2
1983	39.4	242.1	202.7
1982	35.8	231.3	195.5
1981	33.2	212.2	179.0
1980	48.5	201.8	153.2
1979	25.6	193.2	167.5
1978	20.5	177.7	157.2
1977	8.0	164.4	156.4
1976			145.3
1975			140.2
1974			112.8
1973			114.6
1972			110.0
1971			106.4
1970			97.6
1969			44.5

REVENUE ESTIMATES

Production data multiplied by the price per unit of production gives gross revenues. The question is how to obtain an accurate estimate of the price per barrel of ANS crude oil given that the oil is disposed of at different prices.

There are several estimates of ANS per barrel revenue which must be considered when preparing a total revenue estimate. The approach used here was based primarily on the weighted average of the reported per barrel prices given in the producers' corporate annual reports. Adjustment was made to reflect the transportation and quality differences between Kuparuk and Prudhoe Bay crude. These adjustments were based on information provided by Salomon Brothers and Barclay's.

The first set of data used were the reported per barrel prices for crude oil obtained from the annual reports of Sohio and Arco as well as the *U.S. Energy*

Statistics Sourcebook. These data are presented in columns 1 through 3 respectively of Table I-6. In 1988, Barclay's produced a report on BP which, among other things, detailed revenues at Pump Station 1 for 1985 through 1987. This information is included in column 4 of Table I-6 for comparison.

Estimates given in Table I-6 are based on overall production. It is necessary to disaggregate the data for Prudhoe Bay and for Kuparuk. Given that Arco reported production for both fields, and that its per barrel revenue is, effectively, a weighted average of the prices from these two fields, it is possible to disaggregate the prices if the difference between the two prices is known. The difference between the Prudhoe Bay price and the Kuparuk price would be due to the Kuparuk pipeline tariff and a quality differential between the two fields.

Table I-6
Per Barrel ANS Revenue Data
(Pump Station #1)

Year	*Sohio*	*Arco*	*Sourcebook*	*Barclay's*
1987		$ 10.95	$ 10.84	$ 10.74
1986	$ 7.38	6.43	6.45	6.76
1985	16.92	16.81	16.98	17.83
1984	17.78	17.11	17.91	
1983	17.73	17.31	17.69	
1982	19.97	19.08	19.92	
1981	23.86	22.65	23.23	
1980	16.79	16.95	16.87	
1979	10.72	na	10.57	
1978	4.56	na	5.21	
1977			5.84	
1976			5.02	
1975			4.92	
1974			3.62	
1973			3.23	
1972			3.17	
1971			3.01	
1970			2.90	
1969			na	

According to Barclay's, the Kuparuk pipeline tariff is $1.00 per barrel. Barclay's also estimated that the quality differential is $.50. For the years 1982 and 1983, these estimates are consistent with other sources. Therefore, the

Kuparuk price should be $1.50 per barrel less than the Prudhoe Bay price for 1982 and 1983. In 1984, the new Kuparuk pipeline was brought on stream and a new pipeline tariff established. *Petroleum Intelligence Weekly* (February 1988) and other sources indicate that the price difference between Prudhoe Bay and Kuparuk for 1982 and 1983 should equal $.95 per barrel. In later years the difference declines. The $.95 per barrel differential together with the average per barrel ANS price data were used to construct estimates of the price of crude oil for each field.

The formula for generating these estimates is developed as follows. For 1984 through 1987, Arco's average per barrel price:

$$\frac{P_{Kuparuk} \times (X - \$0.95) + P_{Prudhoe} \times X}{\text{Total Production}}$$

Where P = Production for each field and
X = Price for Prudhoe Bay

Using the formula for 1987, for example, gives the following price estimates:

$$\frac{122.0 \times (X - \$0.95) + 324.9\ X}{446.9} = 10.95$$

$$X \text{ (Prudhoe Bay Price)} = \underline{11.21}$$

$$X - \$\ 0.95 \text{ (Kuparuk Price)} = \underline{10.26}$$

Similar estimates are obtained for each other year when Kuparuk was in production.

The amounts reported in Table I-6 and the field prices obtained from the calculations discussed above provide a starting point for determining the final estimate. The per barrel revenue amounts for Arco are widely believed to be greater than for Sohio because a greater portion of Arco's ANS crude is disposed of on the U.S. West Coast and, therefore, avoids the extra cost of the longer marine voyage and trans-Panama shipment.[2] The realizations for Exxon are

[2]See Barclay's de Zoete Wedd (1988), *Petroleum Intelligence Weekly* (Feb. 1, 1988) and Salomon Brothers (1987) for discussions of the differences in dispositions.

also believed to be somewhat greater than for Sohio because Exxon's dispositions occur almost exclusively on the U.S. West Coast. For these reasons, the per barrel data given in Table I-6 probably understate actual realizations. This belief is confirmed by reports by financial analysts such as Salomon Brothers and *Petroleum Intelligence Weekly* who use higher realization prices for Arco's ANS crude.

As a result of all these factors, it appeared that the revenue number needed to be adjusted for the greater proportion of dispositions on the West Coast by producers other than Arco and Sohio. Examination of price differentials for West Coast and Gulf Coast dispositions as well as cost differences suggests that, conservatively, crude oil disposed of on the West Coast should have a value that is approximately $1 per barrel greater on the North Slope than crude oil disposed of elsewhere. Because public data are limited on the precise value of each North Slope company's crude oil, the revenue here is based on the assumption that Arco and Sohio's average disposition prices were as reported in their 10-K's and that other producers obtained an average of $1 more per barrel for their crude. The difference is presumed due to Arco's netback method. The results are more consistent with outside analysts' observations and tie more closely to the State's reported severance tax collections. The Alaska Department of Revenue's report of revenue sources states that severance tax collections totalled $10.2 billion over the period 1969 through 1987. The analysis in this report gives a total severance tax collection of $10.4 billion. The amounts are within a 2.3% margin of error.

Estimates of total revenue for Prudhoe Bay were calculated by using a weighted average price for Prudhoe Bay crude oil. It was assumed that 51% of Prudhoe Bay crude was sold at the price reported by Sohio and 21% at the price calculated for Arco. The remaining 28% of Prudhoe Bay production was

assumed to have been sold at a price that was $1 per barrel greater than that reported by Arco. This approximates the dispositions indicated in other information sources.[3] Data were available to make these calculations for the years 1980 through 1986. In 1987, Sohio was no longer in existence as a separate entity. Its successor, BP America, did not report weighted average ANS crude prices. Dividing BP America's Alaska revenues by its ANS production gives a substitute estimate. For 1978 and 1979, data limitations required use of Sohio's prices. The 1977 average price was based on the *U.S. Energy Statistics Sourcebook* because other data were not available. Comparing all of the different estimates across time, it does not appear that using different base estimates will have a significant effect on the results.

An alternate method for computing Prudhoe Bay revenue is to take Sohio's price per barrel times total production. This should provide a lower overall estimate since Sohio's price realizations are expected to be lower due to their additional transportation costs.[4] The weighted-average revenue estimate used in this report is 1.19% greater over the eleven-year production history. Given that Sohio's prices are expected to be lower, this lends further support to the assertion that the estimate used in this report is reasonably close, and probably somewhat conservative, relative to the actual revenue realized.[5]

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[3]It may be possible to derive more accurate estimates of revenue. Examination of public and private data sources indicated in the list of references suggests that the resulting revenue estimates will be somewhat greater than those reported here.

[4]The per barrel prices reported in the 10-K are different from what one would expect given that Sohio's transportation costs downstream of Valdez are higher than the costs for Arco. The reasons for this discrepancy are unknown. The *Sourcebook* data series and the Barclay's data suggest that the per barrel numbers used here are not consistently the highest nor the lowest. Moreover, the different series are usually within a few cents per barrel of each other. At best, it appears that the data are approximately consistent. It is not possible to obtain an exact estimate of these revenues.

[5]Indeed, on a weighted average basis over the life of ANS production, an estimate using Sohio's price alone should be approximately 7% lower than actual realizations.

Kuparuk revenue was based on the calculated Kuparuk price per barrel times the production estimate for Kuparuk. The Kuparuk price was estimated by taking the weighted average Prudhoe Bay price and deducting $0.95 per barrel for the years 1984 through 1987 and deducting $1.50 per barrel for 1982 and 1983. The results conform to the prices reported in such other sources as *Petroleum Intelligence Weekly*, Salomon Brothers and Barclays de Zoete Wedd (1988).

For 1977 through 1987, price data for non-ANS crude was obtained from DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1988), which is derived from U.S. Department of Energy statistics. The DeGolyer and MacNaughton data report Tier I and Tier II prices, but do not indicate how much crude was sold under either price level. For lack of any available data, it has been assumed that 1/2 was Tier I and 1/2 was Tier II. Prior to 1977, the composite published Alaska prices are directly available from the *U.S. Energy Sourcebook*. Other Alaska crude oil revenue was based on the AOGCC production data times the prices obtained from DeGolyer and MacNaughton for 1978 through 1987 and from the *Sourcebook* for prior years. There does not appear to be a substantial difference between the estimates obtained under other methods not described here.

A summary of the estimated revenues realized for Prudhoe Bay (including Lisburne), Kuparuk (including Milne Point) and all other Alaska crude oil production is provided in Table I-7. These revenue data are net of royalty. In Section III, an adjustment is made to add royalty to these revenues and then to deduct it as an expense.

Table I-7
Crude Oil Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Other Alaska*	*Total*
1987	$5,695	$ 942	$ 232	$6,869
1986	3,729	575	191	4,495
1985	8,600	1,145	343	10,088
1984	8,842	685	468	9,995
1983	8,823	631	539	9,993
1982	9,842	528	674	11,044
1981	11,665		873	12,538
1980	8,304		284	8,568
1979	5,136		285	5,421
1978	1,587		291	1,878
1977	631		262	893
1976			294	294
1975			329	329
1974			311	311
1973			232	232
1972			208	208
1971			218	218
1970			221	221
1969			189	189

Natural Gas. Natural gas price estimates were available for Arco for the years 1983 through 1987. Sohio presented natural gas price data for 1977 through 1986. These numbers were used to estimate revenues from natural gas on the North Slope for the years when Prudhoe Bay was in production. The numbers are relatively close in amount. A weighted average was used for the years when both Arco and Sohio published these data. The assumption was that the Arco price was attributable to 76% of the production, the Sohio price was attributable to 24%, and the missing data are proportional to these numbers. Separate data were not available for Kuparuk.

Other Alaska gas prices were based on the *U.S. Energy Sourcebook* unit prices and are shown in column 3 of Table I-8. All of the unit price data are given for comparative purposes in Table I-8.

Table I-8
Natural Gas Price Data
(dollars per thousand cubic feet)

Year	*Sohio*	*Arco*	*Sourcebook*
1987		$ 1.14	$ .50
1986	$ 1.06	1.16	.74
1985	1.06	1.28	.73
1984	1.06	1.10	.73
1983	1.97	1.03	.63
1982	2.20		.62
1981	2.08		.73
1980	1.96		.52
1979	2.00		.52
1978	2.02		.40
1977	na		.39
1976			.30
1975			.17
1974			.18
1973			.15
1972			.24
1971			.25
1970			.25
1969			.25

na. Not available.

Multiplying the unit price data from Table I-8 times the production data from Table I-5 gives an estimate of total revenues. The revenue estimates for natural gas are given in Table I-9.

A comparison of Table I-9 with Table I-7 shows that natural gas revenues are not significant in dollar terms for the Alaska North Slope. Hence, the inability to subdivide ANS natural gas revenues between Prudhoe Bay and Kuparuk will not have a meaningful effect on the analysis. By contrast, natural gas revenues are significant for the remainder of Alaska. In some years they account for more than one-half of the reported revenues.

Table I-9
Natural Gas Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Other Alaska*	*Total*
1987	$ 91	$ 117	$ 208
1986	80	145	225
1985	68	165	233
1984	46	154	200
1983	49	128	177
1982	79	121	200
1981	69	131	200
1980	95	80	175
1979	51	87	138
1978	41	63	104
1977		61	61
1976		44	44
1975		24	24
1974		20	20
1973		17	17
1972		26	26
1971		27	27
1970		24	24
1969		11	11

Combining natural gas revenues from Table I-9 with the crude oil revenues reported in Table I-7 yields the total revenue estimates for each major area in Alaska. These estimates are shown in Table I-10. It is these revenue estimates that form the basis for the profit analysis which follows. To obtain profit, it is necessary to deduct expenses incurred to earn the revenues reported in this section. Estimation of these expenses is the next topic in this report.

Table I-10
Producers' Revenue Data
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Other Alaska*	*Total*
1987	$5,786	$ 942	$ 349	$7,077
1986	3,809	575	336	4,720
1985	8,668	1,145	508	10,321
1984	8,888	685	622	10,195
1983	8,872	631	667	10,170
1982	9,921	528	795	11,244
1981	11,734		1,004	12,738
1980	8,399		364	8,763
1979	5,187		372	5,559
1978	1,628		354	1,982
1977	631		323	923
1976			338	338
1975			353	353
1974			331	331
1973			249	249
1972			234	234
1971			245	245
1970			245	245
1969			200	200
Totals	**$73,523**	**$4,507**	**$ 7,889**	**$85,918**

II. PRODUCTION EXPENSES

Production expenses fall into nine major categories: depreciation, severance taxes, operating expenses, windfall profit taxes, exploration costs, overhead, interest, state and federal income taxes. Federal income taxes, severance taxes and depreciation are larger in amount relative to the other expenses. Overhead, interest and state income taxes are relatively low. The ability to estimate each of these cost categories accurately varies. The most difficult to estimate are overhead and interest. Fortunately, these are relatively small in amount. Severance taxes and depreciation are relatively easy to estimate. Federal income tax estimates depend on several assumptions. The effect of the assumptions on reported profit is tested later in this technical discussion.

Each of the expense categories and the method of determining the expense is discussed in this section.

DEPRECIATION

Depreciation represents a pro rata share of the initial cost of the investment in drilling, lease acquisition, production facilities and other similar costs over the periods or products that benefit from those investments. Depreciation expense also includes a provision for future dismantlement of the facilities and for restoration of the affected sites. Unlike most other expenses, depreciation does not require a current outlay of cash; it is a current accounting for a prior or an anticipated outlay.

There were three company sources for estimates of depreciation on the Alaska North Slope: (1) BP America's 1987 annual report, (2) Sohio's annual reports from 1977 to 1986, and (3) Arco's 10-K's. In addition, the public data reported here were compared to Alaska property tax information. The results

suggest that use of private data would tend to support the findings reported here. The data and the limitations of the data from each source is addressed in turn.

In its 1987 Annual Report, BP America provided an estimate of its 1986 and 1987 Alaska depreciation which, when divided by its Alaska production, gave a per barrel depreciation amount. However, when BP purchased the outstanding shares of Sohio, it paid a premium over the book value of the assets of Sohio. BP added this premium to its asset base and depreciated this premium along with the cost of the assets. As a result, BP America's Alaska depreciation reflects not only a portion of the costs actually incurred in Alaska, but an additional amount which reflects payments to Sohio shareholders. This latter amount was not part of the cost to acquire oil producing facilities in Alaska. Rather, it reflects BP's purchase of shares from Sohio stockholders. The amortization of this cost is not a cost of operating BP America's Alaska properties, but rather is a transfer payment.[6] As a result, BP America's depreciation numbers overstate amortization of the costs incurred in Alaska and would understate profit.

In its annual reports for 1981 to 1986, Sohio provided a per barrel total production cost amount with and without depreciation. Subtracting the reported production costs without depreciation from production costs with depreciation yields the depreciation per barrel for Alaska production.

Certain of Arco's 10-K reports stated its depreciation charge for Alaska production activities as a total dollar amount. Dividing these amounts by each year's Alaska production volumes gave an estimate of Arco's per barrel Alaska depreciation. This is referred to below as the Arco production-based estimate.

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[6]See Barclay's de Zoete Wedd 1988 report on British Petroleum, p. 4, for the reasons why BP was willing to pay a premium for the remaining outstanding shares of Sohio.

Arco's 10-K also gave its Alaska producing property plant and equipment. When these amounts were divided by Arco's proved reserves each year, an alternate estimate of per barrel depreciation was obtained. This is referred to as Arco's reserve-based estimate. These are composite estimates for all Alaska production, so that adjustments are necessary to obtain estimates for crude oil for each significant field. The alternate estimates are given in Table II-1.

Table II-1
Unit Depreciation Data
($ per equivalent barrel)

			Arco	
Year	*BP America*	*Sohio*	*Production*	*Reserves*
1987	$ 2.83		$ 2.21	2.49
1986	2.26	$ 2.15	2.56	2.62
1985		1.51	2.47	2.47
1984		1.34	1.65	2.17
1983		1.14	1.81	1.92
1982		1.11	1.56	1.73
1981		1.07	1.30	1.23
1980		1.05		.96
1979		.90		
1978		.84		

These depreciation numbers reflect a weighted average of both Kuparuk and Prudhoe Bay. It is generally recognized that Prudhoe Bay depreciation is lower than Kuparuk. For example, Barclay's de Zoete Wedd (1988) reported Prudhoe Bay depreciation in 1987 at $2.00 per barrel and Kuparuk at $3.80. If Barclay's estimates are correct, and assuming that Arco's depreciation is approximately equal to Sohio's, Arco's 1987 weighted average depreciation per barrel should equal:

$$\frac{\$3.80 \times 122 + \$2.00 \times 340}{122 + 340} = \$2.475$$

where 122 and 340 represent Arco's daily average production from Kuparuk and Prudhoe Bay (plus Lisburne) fields as shown in Table I-1, above. Based on this calculation, $2.475 should be the weighted average per barrel depreciation shown in Arco's annual reports. However, Table II-1 suggests that Arco's

weighted average depreciation is about $2.21 to $2.49. Averaging these two estimates gives $2.35, which is probably the best estimate of Arco's North Slope production depreciation available from Arco's financial statements.[7] This suggests that the $3.80/$2.00 estimates of depreciation for each field are too high.[8]

Given that Sohio's weighted average depreciation number for 1986 was $2.15 and that was an average of the lower-depreciation Prudhoe Bay and the higher-depreciation Kuparuk, it is likely that Arco's 1986 Prudhoe Bay depreciation was no more than $2.15 per barrel. This amount is slightly higher than the Barclay's estimate. Presumably, Sohio's depreciation for Prudhoe Bay alone would be lower than $2.15, so the basis used here could result in an understatement of profit. Assuming Prudhoe Bay depreciation is $2.15 per barrel, then we can solve for Kuparuk using the equation:

$$462 \times \$2.35 = 122\,X + 340 \times \$2.15$$

$$X = \underline{\$2.91}$$

This equation states that Arco's weighted average depreciation per barrel ($2.35) should equal the Kuparuk production times the unknown depreciation for Kuparuk plus the estimated $2.15 per barrel depreciation for Prudhoe Bay. The result suggests a $2.91 per barrel depreciation estimate for Kuparuk.

If Kuparuk depreciation is $2.91 per barrel, then Prudhoe Bay depreciation per barrel for the years when Kuparuk and Prudhoe Bay were both in production is as given in Table II-2, below. The numbers in Table II-2 should be compared

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[7]Salomon Brother's financial analysis of Arco's operations states that Arco's Alaska depreciation is lower than Sohio's. This is the opposite of the data from the financial statements. Public data are not available which would enable us to resolve this disparity. The data in this report are based on the higher estimate from the 10-K's, even though this may overstate depreciation and understate profit.

[8]Salomon Brothers Inc. reported an estimate of $1.60 per barrel 1985 depreciation for Prudhoe Bay and $1.75 for 1987. They reported 1985 Kuparuk depreciation at $3.75 per barrel and 1986 at $3.55 This confirms the suggestion that Barclay's Prudhoe Bay depreciation is too high. The effects of alternate depreciation estimates on the reported profit for each field are discussed in Section III.

with other sources. For example, *Petroleum Intelligence Weekly* estimated Prudhoe Bay depreciation at $2.25 in 1987, $2.17 in 1986 and $1.53 in 1985. Salomon Brothers estimated Arco's Prudhoe Bay depreciation at $1.80 in 1987, $1.75 in 1986 and $1.60 in 1985.

Table II-2
Estimated Prudhoe Bay Depreciation
($ per barrel)

Year	*Amount*
1987	$ 2.15
1986	2.25
1985	1.75
1984	1.44
1983	1.29
1982	1.19
1981	1.05
1980	.98
1979	.78
1978	.73
1977	.38

These data are higher than Sohio's reported weighted average depreciation charges, but appear more reasonable than the Barclay's numbers. The numbers are lower than Arco's weighted average, which is consistent with expectations. Moreover, they are higher than the Salomon Brothers numbers. In brief, depreciation based on these numbers is a "middle-of-the-road" approximation.

Since depreciation expense for each field was computed using a weighted average based on working interest production from each field, total depreciation for both fields taken together will be approximately the same. That is, Prudhoe Bay might be assigned too much depreciation as a result of this process, but that will be offset by lower depreciation charges to Kuparuk. The "bottom-line" effect of this is discussed in Section III.

Prior to the start of Kuparuk production, depreciation estimation is simplified. For each of the years 1978 through 1981, a weighted average of the reported per-barrel depreciation numbers for Arco and Sohio was used. There was one

estimate of Sohio's depreciation each year. There were three Arco estimates in 1981, two in 1980, and one for each of 1978 and 1979. It was assumed that Sohio's depreciation number was applicable to 72% of field production and Arco's to 28%. This ratio reflects Sohio's 53% of overall production to the total production for which depreciation data are available (53% Sohio; 21% Arco). It is assumed that the missing data equals a weighted average of the available data.

For 1977, the only depreciation estimate was that based on Arco's production. Lacking any alternate estimate, it was used for that year. Since production in that year was relatively low, it is unlikely that changing the estimate by a reasonable amount will have a substantial effect on the results.

Per-barrel depreciation estimates for Prudhoe Bay are reported in Table II-2, above. Kuparuk depreciation is estimated at $2.91 per barrel. Although this estimate of Kuparuk depreciation is lower than that reported by some of the financial analysts discussed above, Barclay's reports that Kuparuk had an original estimated 1.9 billion barrels of recoverable crude oil. Given estimated investment in Kuparuk of $4.3 billion a depreciation charge of $2.28 per barrel (i.e. $4.3 billion/1.9 billion) is indicated. The $2.91 per barrel estimate may result in understatement of Kuparuk profit.

Total depreciation for each field is the product of crude oil production times the per-barrel amount. For non-ANS production, gas is converted to equivalent barrels using the standard 6 mcf of gas = 1 bbl. crude oil energy content ratio. It was assumed that non-ANS depreciation per barrel was 1/3 of ANS per-barrel depreciation. Use of this assumption yields total depreciation amounts that are relatively close to what one would expect given non-ANS investment and production levels. Total depreciation amounts for each year are presented in

Table II-3. These data represent the depreciation expense numbers included in the production profit estimates in Section III.

Table II-3
Total Depreciation Expense
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total Alaska*
1987	$1,074	$ 263	$ 1,394
1986	1,110	253	1,418
1985	873	204	1,123
1984	710	117	866
1983	632	112	779
1982	581	83	698
1981	510		540
1980	476		504
1979	320		345
1978	254		280
1977	38		53
1976			16
1975			16
1974			16
1973			16
1972			16
1971			16
1970			17
1969			14
Totals	**$6,579**	**$1,032**	**$8,127**

SEVERANCE TAXES

Severance taxes are levied on the gross value of production which accrues to producers (i.e., working interest production). In Alaska, prior to 1981 severance taxes were 12.25% of production. Subsequent to 1981, the amount was revised to 15% of production (except that it remained 12.25% for the first five years of a field's commercial production). An economic limit factor is applied to production from each field which causes the actual severance tax to be lower than the statutory rate. The 1981 Legislation suspended the application of the economic limit factor at Prudhoe Bay until mid-1987. Prior to 1981, it was estimated that the severance tax on Prudhoe Bay production averaged approximately 11%. From 1982 to mid-1987, the Prudhoe Bay severance tax was estimated at 15%. From the middle of 1987 on, the Prudhoe Bay severance

tax was estimated at 12.25%.[9] Severance taxes on Kuparuk production have been estimated to range between an effective rate of 8% and 9%. A 9% rate was used for this study for Kuparuk. Recent severance tax returns suggest that by 1987 the economic limit factor reduced severance taxes on non-ANS Alaska production to close to zero. The effect of changes in the non-ANS depreciation amounts does not have a meaningful impact on reported profit.

To determine profit from oil producing activities, it is necessary to deduct severance taxes from revenues. Severance taxes are not reported separately for Alaska production in the annual reports of the producers. Therefore, the effective severance tax rates were applied to revenues reported here to obtain estimated severance tax expense for 1977 through 1987 for each field. For prior years, Alaska Department of Revenue reported collections were used as the severance tax expense. This amount corresponds closely to the expense that would be estimated if the statutory rate were applied to the production values.

The Alaska Department of Revenue reports severance tax collections from oil production in Alaska. Over time, severance tax expense as deducted to compute profit should tend to equal severance tax collections by the state. There is one significant wrinkle in this comparison. In 1975, the State levied a reserves tax which was allowed as a later credit against severance tax due later. The amount of the reserves tax was $493.7 million. This tax was considered a credit against severance tax payments due. Thus, when comparing severance tax collections to recorded expense, it is necessary to include this $493.7 million as a collection.

The estimated severance taxes for Prudhoe Bay, Kuparuk, non-ANS, and the total expense are summarized in Table II-4. These amounts are compared to

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[9]Effective severance tax rates are based on *Petroleum Intelligence Weekly* (February 1, 1988).

severance tax collections, including the reserves tax, as reported by the Department of Revenue. The results of the comparison indicate that the estimates are quite close to collections as they should be over time.[10]

Table II-4
Severance Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Non-ANS Alaska*	*Total Expense*	*Revenue Collections#*	
1987	$ 787	$ 85	$ 0	$ 871	$ 649	
1986	571	52	0	623	1,108	
1985	1,300	103	0	1,403	1,389	
1984	1,333	62	0	1,395	1,393	
1983	1,331	57	0	1,388	1,494	
1982	1,488	48	0	1,535	1,572	
1981	1,291		0	1,291	1,170	
1980	924		0	924	507	*
1979	622		0	622	174	*
1978	195		0	195	108	*
1977	76		0	76	295	*
1976			28	28	251	*
1975			27	27	27	
1974			22	22	22	
1973			11	11	11	
1972			11	11	11	
1971			11	11	11	
1970			8	8	8	
1969			6	6	6	
Totals	**$9,918**	**$ 406**	**$ 124**	**$10,441**	**$10,206**	

* Reflects differences due to reserves tax included in 1976 and 1977 collections but credited against later liabilities.

#Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons.

It is likely that some of non-ANS production during 1977 through 1987 incurred a severance tax liability. However, the amounts are too low to affect the analysis. Total severance tax expense reported in the analysis of profit is $10,441 million. Total actual tax collections amount to $10,206 million. The difference is 2.3%. It is possible that this difference is due to overstatement of effective severance tax rates or the delay between the time when severance

[10]Expense should exceed collections because collections are reported when received by the Alaska Department of Revenue and expenses are reported when the related production occurs.

taxes are due and when they are collected. The difference may also be due to the revenue estimates used. In any event, it is unlikely that the differences will have a significant effect on the results of the analysis.

OPERATING EXPENSES

Operating expenses are those costs which are necessary to continue production from an oil or gas field. They include well workover costs, fuel, maintenance and similar items. Information on these costs for the years 1980 to 1986 is available in the corporate annual reports of Sohio. Financial analyst reports include estimates of operating expenses as determined through meetings with company officials as well as based on their evaluation of operating costs.

For this report, operating expenses reported by Sohio were analyzed first. Sohio reports operating expenses combined with production taxes, windfall profit taxes and its net profits interest payments to BP America. It was necessary to separate production and windfall profit taxes from Sohio's reported data since these taxes are reported on another line in this income statement. The net profits interest payments to BP America would be an expense to Sohio, but a revenue item to BP America. This is a transfer payment between two field owners. The transfer payment needs to be cancelled when estimating income for the total project.

Net profits interest payments were reported in the notes to Sohio's financial statements. Severance taxes were estimated using the effective severance tax rates times the reported revenues. Windfall profit taxes were reported on a per-barrel basis in Arco's annual reports. These estimates were used to obtain an estimate of Sohio's windfall profit taxes. As described below, the resulting estimated windfall profit tax expense was lower than the reported windfall profit

tax collections by the U.S. Internal Revenue Service. As a result, the estimates of operating expenses may be higher than actual.

Table II-5 summarizes Sohio's reported production expenses, the computed estimates of severance and windfall profit taxes and the net profits interest payments to BP. The last column of Table II-5 is estimated operating expenses for the ANS based on the Sohio data.

Table II-5
Sohio's Operating Expenses
(millions of dollars)

Year	*Production Costs*	*Severance and Windfall Profit Taxes*	*Net Profits Interest*	*Operating Expenses*
1986	$ 727	$ 271	$ 44	$ 412
1985	1,216	680	108	428
1984	1,113	649	36	428
1983	1,021	699	0	322
1982	1,685	1,199	92	394
1981	2,550	2,030	153	367
1980	1,181	862	145	174

The resulting operating expenses were analyzed to see if they were mathematically related to revenues or production. It appeared that the operating expenses were not related to revenues and were only weakly related to production levels. Regression analysis, a statistical technique used to compare two sets of data (such as operating expenses and revenues), found no relationship between the numbers. This leads to the suggestion that these expenses are fixed costs. Further study of the expenses showed that they increased when the Prudhoe Bay waterflood project was installed and when the gas reinjection recovery program was installed. This further supports the suggestion that these costs are fixed with respect to annual production and revenues.

The best available overall estimate of production costs, then, is based on the relationship of Sohio's interest in Prudhoe Bay field. Thus, total ANS operating

expenses are estimated as equal to Sohio's operating expenses divided by Sohio's interest in Prudhoe Bay field. These expenses were subdivided between Prudhoe Bay and Kuparuk based on relative revenues from each field. Admittedly, this may misstate the precise relationship since operating expenses are not a function of annual revenues. However, there are no other direct operating expense data sources available publicly from the companies. The results of the calculations used for this estimate are presented in Table II-6.

Table II-6
Estimated Total Operating Expenses
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 890	$ 218	$1,137
1986	662	152	845
1985	685	160	867
1984	726	120	850
1983	541	96	659
1982	651	92	771
1981	692		722
1980	328		335
1979	307		318
1978	261		289
1977	76		95
1976			28
1975			27
1974			23
1973			16
1972			14
1971			15
1970			15
1969			12
Totals	**$5,820**	**$ 837**	**$7,038**

Production costs for 1987 and for 1977 through 1979 were estimated based on an approximate relationship between revenues and these costs. Given the lack of other company data on these costs, reliance on revenues is one way available to approximate the operating expenses for the missing years.[11] There is a significant increase in the estimated operating expenses between 1980 and

[11]Although production costs are not related to revenues mathematically, there are relatively few options available for estimating costs attributable to each field. Since production costs are low relative to revenues, it is probable that the effect on reported profit is minor.

1981. This is probably due to the differences in windfall profit taxes included in the Arco data used to derive the windfall profit tax number and the Sohio data used as a basis for operating costs before deducting windfall profit taxes. As noted in the section on windfall profit taxes, Arco-based windfall profit tax numbers result in an expense that is lower than when using the I.R.S. collection data. It is possible that the use of Arco windfall profit tax numbers in the operating cost computation overstates operating costs with a resulting understatement of profit.

Other analysts such as *Petroleum Intelligence Weekly* and Salomon Brothers estimate that operating costs amount to an average of $1 per barrel of ANS crude oil production. *International Petroleum Finance* estimates operating costs at $.91 per barrel. The results here average $1.08 per barrel. Therefore, even though the expense number is calculated based on a number of assumptions, the outcome of the calculations follows closely, and conservatively, the costs indicated by other observers.

For 1984 to 1986, the operating costs per barrel for the Prudhoe Bay field should be greater than in prior years due to installation of the waterflood program. Since the method used here is based on a combined operating cost for Prudhoe Bay and for Kuparuk, it is probable that the costs for Kuparuk are somewhat overstated during 1984 to 1986 and the costs for Prudhoe Bay are understated by a like amount. The results could be a shifting of profit from Kuparuk to Prudhoe Bay in the amount of up to $100 million over the six-year period of Kuparuk operations. It does not appear that this is a significant amount relative to the profit for each field.

Production costs also include property taxes. Company data do not show the property taxes in Alaska separate from other production costs. Therefore, it is necessary to use alternate sources. Barclay's estimated Prudhoe Bay property

taxes at $.50 per barrel and Kuparuk at $.30. Non-ANS was estimated at $.25. The results were compared to Department of Revenue data and are comparable.

Production costs, net of property taxes, are obtained by deducting the property tax collections from the production costs reported in Table II6. Table II-7 shows the Alaska and municipal property taxes for the areas covered in this report. Table II-8 gives the production expenses net of property taxes.

Table II-7
Property Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 150	$ 44	$ 197
1986	148	41	192
1985	150	35	188
1984	148	20	172
1983	147	17	159
1982	147	14	165
1981	146		151
1980	146		152
1979	123		130
1978	104		113
1977	30		31
1976			12
1975			13
1974			13
1973			13
1972			13
1971			13
1970			14
1969			13
Totals	**$1,438**	**$ 171**	**$1,754**

Table II-8
Operating Expenses
Net of Property Tax
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 740	$ 174	$ 940
1986	514	110	653
1985	535	125	679
1984	578	100	678
1983	394	77	500
1982	504	78	606
1981	546		571
1980	182		183
1979	184		188
1978	157		176
1977	46		63
1976			14
1975			15
1974			10
1973			3
1972			1
1971			2
1970			1
1969			1
Totals	**$4,382**	**$ 666**	**$5,284**

WINDFALL PROFIT TAXES

The Crude Oil Windfall Profit Tax Act of 1980 levied a tax on the "windfall profit from a barrel of crude oil." The windfall profit was defined as the difference between the base price (essentially the price before oil price decontrol) and the selling price. The tax was in effect until 1988 although crude oil price declines rendered the effective amount of the tax at zero for years after 1985. In addition, ANS fields outside the Sadlerochit reservoir were exempt from the tax.

There are two primary sources of data concerning the windfall profit tax on Alaska crude oil production. The first is Arco's reported windfall profit tax per barrel of Alaska crude oil production. The second is the U.S. Internal Revenue Service *Statistics of Income Bulletin* which reported the aggregate windfall profit tax collections on ANS crude oil as a separate line item. Arco's per barrel windfall profit tax statistics are reproduced in Table II-9.

Table II-9
Windfall Profit Tax per Barrel
Arco Annual Report Data
($ per barrel)

Year	*Amount*
1985	$ .05
1984	.11
1983	.42
1982	1.59
1981	4.80
1980	2.03

To obtain the total windfall profit tax attributable to Prudhoe Bay, the Arco per barrel numbers were multiplied by field production. In addition, the Arco per barrel numbers were multiplied by the ratio of the all-company average field price to the Arco reported field price. This latter adjustment is designed to reflect the fact that other producers sold their ANS crude for a price that was different than that reported by Arco.[12]

Estimates of non-ANS crude windfall profit taxes were constructed by estimating the windfall profit on this crude and multiplying by a composite windfall profit tax rate. It was assumed that 1/2 of the crude was taxed at the 70% rate for old oil and 1/2 was taxed at a 30% rate. The base price was estimated as equal to the 1979 Cook Inlet price reported by DeGolyer and MacNaughton, adjusted for inflation for 1980 through 1985. The per barrel numbers obtained by this method were as follows in Table II-10:

Table II-10
Non-ANS Windfall Profit Tax
($ per barrel)

1985	$ 0.00
1984	1.42
1983	2.58
1982	5.46
1981	9.42
1980	1.91

[12]See Production Revenue section for further detail on this issue.

These per barrel amounts were multiplied by reported non-ANS production from column 1 of Table I-4 to obtain total windfall profit taxes for other Alaska production.

Estimated windfall profit taxes for Prudhoe Bay field and for all of Alaska are reproduced in column 1 of Table II-11. The computed amounts were compared to the reported collections from the *Statistics of Income Bulletins* shown in column 2 of Table II-11.

Table II-11
Windfall Profit Tax Expense
(millions of dollars)

Year	*Estimated for Prudhoe Bay*	*U.S. Internal Revenue Service ANS Collections*	*All Alaska*
1985	$ 26	$ 39	$ 39
1934	57	211	235
1983	215	426	475
1982	827	1,375	1,491
1981	2,487	3,089	3,314
1980	1,006	797	861
Totals	**$4,618**	**$5,937**	**$6,415**

Table II-11 shows that the U.S. Internal Revenue Service reported higher ANS windfall profit tax collections than those obtained using the Arco data adjusted for estimated price differences among the producers. The possibilities for these discrepancies are two-fold. First, the Arco-based revenue estimates may be too low as noted in the section on Production Revenue. Second, Arco may have had available to it adjustments to the windfall profit tax arising from the net income limitation provisions of the tax act. This part of the Act stated that windfall profit should not exceed 90% of the net income per barrel based on statutory computational rules. The net income limitation provision would not have been captured in the Internal Revenue Service data.

Column 3 of Table II-11 is the sum of the U.S. Internal Revenue Service reported ANS windfall profit tax collections plus the windfall profit taxes estimated for non-ANS production.

The difference between the two data sources is $1.3 billion. In the interest of providing a more conservative estimate of profit from Alaska oil operations, the higher figures of the Internal Revenue Service are used as the basis for Alaska windfall profit taxes.

EXPLORATION EXPENSES

Exploration expenses represent the costs incurred in finding new oil and gas deposits as well as certain costs incurred in defining an existing deposit. Data were not available to assign exploration costs to specific fields during this period. Moreover, there are few data series which overlap, so comparisons across estimates are not possible.

The U.S. Bureau of the Census provides data on Alaska oil industry exploration expenditures for 1978 to 1982 through its *Current Industrial Surveys.* The American Petroleum Institute *Joint Association Survey* provided the 1984 estimate of exploration expenditures. Both of these sources separated offshore expenditures from onshore. Presumably, the offshore expenditures were in Federal waters. These are the best sources of exploration expenditure data available, but they only were available for the years indicated.

For years prior to 1978, it was estimated that exploration expenditures totalled $25 million per year. This amount was compared to exploration drilling data obtained from the Alaska Oil and Gas Conservation Commission. The AOGCC provides numbers of wells drilled. The estimated exploration expenditures in 1969 to 1977 provided here would have financed the levels of drilling indicated by the AOGCC.

For 1983 and for 1985 to 1986 it was assumed that exploration costs equalled double the amount that Sohio reported as Alaska exploration expenses. It was assumed that 1987 exploration equaled 1986, although this is a conservative estimate. Comparing the amounts provided to the AOGCC drilling statistics indicates that these amounts would have easily financed the exploration activities reported by the AOGCC. Table II-12 shows the estimates of exploration expenses included in determining Alaska oil industry profit.

Table II-12
Exploration Expenses
(millions of dollars)

Year	*Amount*	
1987	$ 288	
1986	288	
1985	514	
1984	258	
1983	818	
1982	647	
1981	419	
1980	176	
1979	174	
1978	274	
1969 - 1977	25	annually
Total	**$ 4,081**	

OVERHEAD AND INTEREST EXPENSES

Overhead expenses are those that by their very nature cannot be traced directly to a particular activity. These costs are common to all activities in the company. The generally accepted accounting procedure is to allocate these costs to each activity that benefits from the cost on some basis that reflects either benefits received or cause-and-effect.[13] Frequently, as here, allocations are made in more than one step. Here, the first step is to allocate company overhead to Alaska operations. The second step is to allocate overhead to each field in Alaska.

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[13]See, for example, E. Deakin and M. Maher, *Cost Accounting 2nd. ed.* (1987), pp. 96 - 101. This topic has been addressed in detail by the former U.S. Cost Accounting Standards Board. The Cost Accounting Standards Board methodology is followed as closely as possible based on available data.

Sohio is the only producing company operating in Alaska from which sufficient data were available to make an allocation of overhead to Alaska activities based on assets and on revenues. In its corporate annual reports, Sohio presents segment information which, among other things, states Sohio's "Corporate and other" expenses. This line item was used as a proxy for the overhead cost.

To allocate this overhead, a two-factor formula was used. The two factors are value of crude production in Alaska to all company sales, and oil and gas property in Alaska to all Sohio property plant and equipment other than property plant and equipment related to the company's "corporate and other" activities.

Sohio data were available for 1977 through 1986. In 1987, BP America succeeded Sohio as a result of BP's buyout of the minority interest in Sohio. This purchase was accounted for by adding the extra funds paid to Sohio shareholders in excess of the book value of the assets received being attributed to the book values of the Sohio assets acquired. In effect, BP increased the accounting-based cost of its Alaska assets by a proportional amount of its payment to Sohio shareholders. This payment did not increase the actual costs expended in Alaska. Rather, it represented a transfer from BP to the former Sohio shareholders. As a result, the 1987 data necessary to perform the allocation would be affected by the amount of this transfer payment. Since this payment would result in attributing costs disproportionately to the actual costs incurred in Alaska, 1987 overhead was estimated by taking 1986 overhead and adding 4.5% for inflation.

A third factor commonly used in these formulas is payroll. These data are not publicly available. If the payroll data were available, the resulting allocation would be lower than that reported here because Sohio has proportionately fewer

employees in Alaska than the average of its assets and sales. The allocation method here used the value of Alaska production relative to total company sales. This ratio includes sales that have not been made to third parties. If third-party sales only were included, the allocation of overhead to Alaska operations would be lower than that reported here.

The result of this calculation is the first step in the allocation of Sohio overhead to all Alaska operations. Dividing the resulting allocation by Sohio's proportionate share in the Prudhoe Bay field yields an estimate of the total overhead attributable to Alaska by all producers. This is based on the assumption that other producers have a similar overhead structure to Sohio's and that the Prudhoe Bay ratio is a reasonable basis for estimating overall overhead. More complex allocations which include estimates of Kuparuk production have insignificant effects on the reported allocation.

To allocate to Prudhoe Bay and Kuparuk, overhead allocated to Alaska was subdivided in proportion to the revenues reported for Prudhoe Bay and Kuparuk. The original data used for the allocations and the results are give in Table II-13.

Table II-13
Overhead Allocations
(millions of dollars)

	-----Sohio Total-----			*-----Allocated to-----*		
Year	*Overhead*	*Assets*	*Revenues*	*Prudhoe*	*Kuparuk*	*Total*
1987				$ 109	$ 20	$ 139
1986	$ 234	$ 14,006	$ 10,022	105	20	133
1985	270	16,468	13,818	139	25	173
1984	160	16,421	12,251	89	11	106
1983	172	15,181	12,067	93	11	111
1982	132	14,347	13,529	77	8	91
1981	86	13,096	14,140	51		55
1980	24	8,506	11,346	15		16
1979	4	7,927	11,346	2		2
1978	-1	8,107	8,222	-		-1
1977	6	7,578	3,523	2		3
Totals				**$ 681**	**$ 94**	**$ 830**

This allocation assumes that overhead is proportional between Kuparuk and Prudhoe Bay. Such an assumption would usually be consistent with general accounting practices.

For lack of any data on the subject it was assumed that overhead for non-ANS activities was proportional to the revenues for those activities.[14] To obtain total overhead attributable to Alaska, the Prudhoe Bay and Kuparuk overhead were increased proportionately by the ratio of total Alaska production revenues to Prudhoe Bay and Kuparuk revenues. For years prior to 1977, overhead was estimated as a percentage of revenues based on the revenue percentage over the years 1977 through 1987. Overhead in each of the years prior to 1977 averaged less than $150,000.

Although these allocations are subjective and complex, they suggest that the overhead amounts are not so highly significant as to have a material effect on estimated profit. Aggregate overhead over the period of ANS production is estimated at $830 million. This is on the order of 2% of total profit. Even major changes in this number will have a minor effect on total profit.

To test one aspect of a source of variation in the overhead allocations, a composite estimate based on Arco's reported corporate and other expense using a two-factor formula was calculated. For most of the period at issue, Arco did not report its Alaska assets separately in its annual reports. These data were obtained from its SEC Form 10-K, Schedule VI.[15] Arco's total assets were obtained from its annual report segment disclosures. Total revenues were

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[14]Non-ANS overhead accounts for approximately 10% of the total overhead reported here. Similarly, non-ANS production is a small portion of total production in Alaska. In addition, as noted for the ANS, overhead is a small portion of overall costs and revenues. The effect of misstatements of the overhead will not have a significant impact on this analysis.

[15]In 1980 and 1981, Arco reported Alaska producing property plant and equipment in its annual report. The amounts were $1,087.7 million and $1,451.1 million respectively. The company reported Alaska property in its 10-K schedule for the same years as $1,789.2 million and $2,273.5 million respectively. The differences are substantial which suggests that the two series may not be comparable.

obtained from the annual report, but Alaska revenues had to be estimated by multiplying reported per barrel prices by reported Alaska production. Assuming that Arco accounted for 21% of Alaska activities and Sohio 51%, weighting the two overhead estimates gave a composite amount of $1,233 million over the period 1977 - 1987.

A second test of overhead variation is to construct an estimate using a payroll factor in the allocation formula. If Alaska payroll is assumed equal to 5% of each company's payroll, estimated overhead attributable to Alaska is $357 million over the period 1977 through 1987. The overhead amount included in the reported profit estimate is midway between these two numbers. Over the same period, the overhead estimate in this report averages 16.1¢ per barrel.

Interest expense was handled in a similar manner. Again, interest costs were based on data from Sohio's corporate annual reports because that was the only readily available source.[16]

Net interest expense for Sohio was reported in Sohio's segment disclosures in its annual reports or on the face of its income statements for 1977 through 1986. Since interest costs are related to the investment in assets rather than to sales, allocations of interest to Alaska were based on the ratio of property plant and equipment in Alaska to total company property plant and equipment. The result of this apportionment was the estimated interest expense attributable to Alaska.

The second step of the interest allocation required producing an estimate of interest attributable to Alaska by all producers. This was based on dividing

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[16]Arco reports some of the data required for this calculation, but the data are reported in different places which may not be consistent as noted in the overhead allocation discussion. It appears that Arco and Exxon experienced a lower overall rate of interest than Sohio. Therefore, Arco's and Exxon's interest costs should be lower than Sohio's. The amounts involved are small relative to the total reported income.

Sohio's assumed Alaska interest expense by its proportional interest in the Prudhoe Bay field. As with the overhead allocation, the results were not particularly sensitive to further refinement. The estimated total Alaska interest expense was subdivided between properties based on depreciation expense. This is more appropriate than sales because depreciation is considered more closely related to assets than to sales. Sohio's total company interest and assets and the resulting estimated interest allocations to the Kuparuk and Prudhoe Bay fields are given in Table II-14.

Table II-14
Interest Allocations
(millions of dollars)

	---Sohio Data---		*-----Allocated to-----*		
Year	*Net Interest*	*Assets*	*Prudhoe*	*Kuparuk*	*Total*
1987			$ 146	$ 32	$ 192
1986	$ 242	$14,006	139	32	183
1985	299	16,468	141	33	183
1984	242	16,421	119	20	148
1983	254	15,181	119	21	150
1982	300	14,347	139	20	171
1981	46	13,096	17		18
1980	22	8,306	10		11
1979	357	7,927	156		167
1978	458	8,107	203		247
1977	246	7,578	117		177
Totals			**$ 1,306**	**$ 159**	**$ 1,675**

The "net interest" column is Sohio's total corporate interest expense net of interest income. The "assets" column is Sohio's total assets less those designated as assets devoted to "corporate" (i.e., overhead) activities. Sohio's portion of net interest expense was allocated to Alaska based on the formula apportionment. The result was "factored up" to reflect an approximation of the total interest expense incurred by all Alaska producers.

For years prior to 1977, average estimated interest expense allocable to Alaska was less than $200,000 per year.

STATE INCOME TAXES

The State of Alaska levies an income tax on the income derived from oil and gas production operations in the State. During the 1977 - 1981 period, this tax was based on a direct measure of the income earned in the state. The statutory tax rate was 9.4% until 1981 when it rose to 11% for that year. Subsequent to 1981, the tax was levied using an indirect method referred to as modified formula apportionment. The latter tax is based not on a direct computation of the revenues accrued less expenses attributable to Alaska, but rather is based on a measure of the proportion of certain Alaska activities to overall company activities. The computed proportion is multiplied by overall company income to derive an estimate of income attributable to Alaska. *Petroleum Intelligence Weekly* suggests that the effective tax rate under this methodology is approximately 3%. As shown in Table II-15, a comparison of tax expense computed at the 3% rate is reasonably close to tax collections.

Individual company data on the Alaska income tax liability is not publicly available. The estimate of Alaska income tax is obtained by multiplying computed Alaska income by the effective tax rates for the periods at issue. The results are reported in Table II-15.

Table II-15
State Income Taxes
(millions of dollars)

Year	*Prudhoe Bay*	*Kuparuk*	*Total**	*Reported Collections**
1987	$ 83	$ 10	$ 92	$ 128
1986	37	2	37	134
1985	165	19	182	169
1984	171	11	189	265
1983	172	10	174	236
1982	168	8	175	669
1981	669		702	860
1980	550		556	548
1979	367		369	233
1978	67		66	33
1977	30		49	36
Prior to 1977			150	150
Totals	**$2,479**	**$ 60**	**$ 2,741**	**3,461**

*Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons. The collections include TAPS income taxes which are estimated to total $900 million.

The estimates differ from collections in part because of differences in the timing of when receipts are received by the State and when the expenses are reported on the income statements. Over the period 1969 through 1987, reported collections totalled $3.5 billion. The income statements here indicate total expenses of $3.6 billion, including the $.9 billion for TAPS. The differences are within a 5% margin of error.

FEDERAL INCOME TAXES

The U.S. government levies taxes on corporate income at statutory rates that ranged from 34% to 48% over the period 1969 through 1987. Under Federal rules, taxable income is net of state income taxes. Certain credits and deductions are allowed in the Federal taxing scheme which reduce the effective tax rates. It has been estimated that during the 1969 through 1980 period, the effective tax rates for oil companies averaged on the order of 29% (*Oil and Gas Journal*, (September 16, 1985), p. 76). This estimate was used for the 1969 to 1976 period.

For Alaska oil income after the start-up of Prudhoe Bay, this estimated Federal rate is unlikely to reflect actual Federal taxes. The taxes currently payable divided by estimated taxable income gives a number referred to as the effective tax rate. One important factor which results in a difference between statutory rates and effective rates is the Federal tax rules designed to provide an incentive to new investment like TAPS and tangible equipment on the North Slope. For example, an investment tax credit equal to 10% of the cost of tangible equipment was in effect during most of this period. This credit would serve to reduce Federal taxable income. That the effective tax rates were lower for Alaska producers may be seen by examining effective tax rates for these producers during the 1977 through 1986 period.

Effective tax rates for the major ANS producers were obtained from their corporate annual reports. The effective rate is the current Federal tax payments divided by reported net income. This information, as available, is reproduced in Table II-16.

Table II-16
Effective Federal Tax Rates

Year	*Arco*	*Sohio*	*Exxon*
1986	-55.49	-52.44	na
1985	40.94	41.53	23.18
1984	33.22	26.56	29.16
1983	19.68	31.60	33.81
1982	17.08	39.06	25.38
1981	16.23	36.41	23.93
1980	16.16	39.37	33.35
1979	12.30	11.22	35.29
1978	6.34	1.34	38.28
1977	na	10.19	na

It is widely presumed that Sohio's financial data was driven almost exclusively by its Alaska operations.[17] For this reason, Sohio's effective tax rates would tend to reflect the actual tax liability for Alaska oil operations during

[17]A review of Sohio's corporate annual repons from 1978 through 1986 indicate that over 90% of its profit arose from its Alaska activities.

the 1977 - 1986 period. Many oil companies, including the ANS producers, wrote-off substantial amounts from losing operations. The significant write-offs taken in 1986 resulted in negative Federal taxes for Alaska oil producers who accounted for most Alaska activities. Therefore, a zero effective Federal rate was used in 1986.

Although financial accounting standards for a company require that recognition be given currently to the possibility that some income tax benefits may need to be paid back to the government in the future, it appears from a review of the effective tax rates in Table II-16 that in this industry, the payback period continues to be deferred indefinitely. Use of current effective tax rates for the purposes of this study reflects better the economic consequences to the company of these investments than the use of statutory rates. In future years as tax benefits decline, these producers may be required to pay taxes in excess of the statutory rate.

With the merger of Sohio into BP, the assumption that Sohio's activities reflect Alaska closely would no longer hold. In addition, beginning in 1987, the tax law reduced many of the incentives for new investment. As a result, actual taxes are probably closer to the statutory rate. Therefore, the 34% statutory rate was used for 1987.

The Federal income tax expense used to estimate Alaska oil production income is reproduced in Table II-17.

These data were obtained by multiplying revenues from Table I-10 less expenses (covered in Tables II-3 (depreciation), II4 (severance taxes), II-6 (operating expenses), II-11 (windfall profit tax), II-12 (exploration expenses), II-13 (allocated overhead), II-14 (allocated interest), and II-15 (state income taxes)) by the related effective tax rates.

Over the entire period 1969 through 1987, Federal income taxes as shown in this report are 32.0% of estimated taxable income. This is higher than the 29% effective rates in the *Oil and Gas Journal* study. The net effect is that the estimates in this report are conservative and may tend to understate actual income.

Table II-17
Federal Income Taxes
(millions of dollars)

Year	*Prudhoe*	*Kuparuk*	*Total*
1987	$ 917	$ 105	$1,007
1986	0	0	0
1985	2,212	247	2,424
1984	1,469	91	1,627
1983	1,756	102	1,774
1982	2,125	104	2,212
1981	1,971		2,067
1980	2,086		2,110
1979	383		399
1978	9		8
1977	32		52
1976			63
1975			68
1974			66
1973			47
1972			44
1971			47
1970			47
1969			37
Totals	**$ 12,960**	**$ 651**	**$ 14,099**

III. PRODUCTION PROFIT

The result of all of the calculations in Sections I and II is to generate a statement which indicates the profit earned from oil and gas production in Alaska. This part of the report is divided into three parts: (1) profit for Prudhoe Bay, (2) Kuparuk and (3) all production in Alaska.

Table III-1
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$6,573	$4,327	$9,847	$10,097	$10,079
Expenses:					
Depreciation	1,074	1,110	873	710	632
Operating Expenses	740	514	535	578	394
Overhead	109	104	139	89	93
Interest	146	139	141	119	119
Royalty	787	518	1,179	1,209	1,207
Severance Taxes	787	571	1,300	1,333	1,331
Property Taxes	150	148	150	148	147
State Income Tax	83	37	165	171	172
Windfall Profit Tax			39	211	426
Federal Income Tax	917	0	2,212	1,469	1,756
Profit	**$1,780**	**$1,186**	**$3,114**	**$4,061**	**$3,801**
Profit per barrel	**$3.55**	**$2.40**	**$6.25**	**$8.26**	**$7.75**

1977 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*	*1977*
Revenue	$11,271	$13,330	$9,541	$5,892	$1,849	$ 717
Expenses:						
Depreciation	581	510	476	320	254	38
Operating Expenses	504	546	182	184	157	46
Overhead	77	51	15	2	0	2
Interest	139	17	10	156	203	117
Royalty	1,350	1,596	1,143	706	221	86
Severance Taxes	1,488	1,291	924	622	195	76
Property Taxes	147	146	146	123	104	30
State Income Tax	168	669	550	367	67	30
Windfall Profit Taxes	1,375	3,089	797			
Federal Income Tax	2,125	1,971	2,086	383	9	32
Profit	**$3,315**	**$3,443**	**$3,212**	**$3,030**	**$ 639**	**$ 260**
Profit per barrel	**$6.78**	**$7.09**	**$6.61**	**$7.39**	**$1.84**	**$2.58**

Total profit over the eleven year production history of the Prudhoe Bay field are estimated as shown in Table III-2. The profit statements in Table III-1 are based on the producers' interest in the production. This is standard accounting practice, but the methodology excludes royalty interests which are important for the State of Alaska. Royalty interests have been estimated as equal to 1/7 of the producers' working interest less a gathering charge of $.63 per barrel. The state royalty is added to the producers' revenue to obtain revenues before royalty as shown in Table III-2.

Table III-2
Total Prudhoe Bay Production Profit
1977 through 1987
(billions of dollars)

Production Revenue	$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Tax	5.9
Federal Income Taxes	13.0
Profit	**$ 27.8 Billion**
Profit per barrel: $5.81	

The estimate of profit from the Kuparuk field is also based on the combination of the data from Sections I and II of this report and is reproduced in Table III-3.

Table III-3
Annual Kuparuk Production Profit
1982 through 1987
(billions of dollars)

	1987	*1986*	*1985*	*1984*	*1983*	*1982*
Production Revenue	$1,055	$ 644	$1,282	$ 767	$ 707	$ 591
Expenses:						
Depreciation	263	254	204	117	112	83
Operating Expenses	174	110	125	100	77	78
Overhead	20	20	25	11	11	7
Interest	32	32	33	20	21	20
Royalty	113	69	137	82	76	63
Severance Taxes	85	52	103	62	57	48
Property Taxes	44	41	35	20	17	14
State Income Taxes	10	2	19	11	10	8
Federal Income Taxes	105	0	247	91	102	104
Profit	**$ 207**	**$ 65**	**$ 351**	**$ 254**	**$ 222**	**$ 165**
Profit per barrel:	**$2.31**	**$.79**	**$5.04**	**$6.28**	**$6.37**	**$5.80**

Combining the data for the six years of Kuparuk production gives overall Kuparuk profit as shown in Table III-4. State royalty was computed for Kuparuk in the same manner as for Prudhoe Bay.

Table III-4
Total Kuparuk Production Profit
1982 through 1987
(billions of dollars)

Production Revenue	$ 5.1
Less Expenses:	
Depreciation	1.0
Operating Expenses	.7
Overhead	.1
Interest	.2
Royalty	.5
Severance Taxes	.4
Property Taxes	.2
State Income Taxes	.1
Federal Income Taxes	.6
Profit	**$ 1.3 Billion**
Profit per barrel:	**$3.66**

Oil industry profit from production activities in Alaska are shown on a year-by-year basis in Table III-5.

Table III-5
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Production Revenue	$8,046	$5,367	$11,735	$11,592	$11,564
Depreciation	1,394	1,418	1,123	866	779
Operating Expenses	940	653	679	678	500
Exploration Expenses	288	288	514	258	818
Overhead	139	133	173	106	111
Interest	192	183	183	148	150
Royalty	970	647	1,414	1,397	1,393
Severance Taxes	871	623	1,403	1,395	1,388
Property Taxes	197	192	188	172	159
State Income Tax	92	37	182	189	174
Windfall Profit Tax			39	235	475
Federal Income Tax	1,007	0	2,424	1,627	1774
Profit	**$1,956**	**$1,192**	**$3,413**	**$4,521**	**$3,841**
Profit per barrel:	**$3.18**	**$2.01**	**$5.83**	**$8.15**	**$6.97**

1978 - 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenue	$12,785	$14,484	$9,961	$6,321	$2,254
Expenses:					
Depreciation	698	540	504	345	280
Operating Expenses	506	571	183	188	176
Exploration Expenses	647	419	176	174	274
Overhead	91	55	16	2	a
Interest	171	18	10	167	247
Royalty	1,641	1,745	1,198	762	272
Severance Taxes	1,536	1,291	923	622	195
Property Taxes	165	151	152	130	113
State Income Tax	175	702	556	369	66
Windfall Profit Tax	1,491	3,314	861		
Federal Income Tax	2,212	2,067	2,110	399	8
Profit	**$3,452**	**$3,610**	**$3,270**	**$3,161**	**$ 623**
Profit per barrel:	**$6.33**	**$6.96**	**$6.21**	**$6.97**	**$1.56**

Table III-5 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

	1977	*1976*	*1975*	*1974*	*1973*
Revenue	$ 1,054	$ 380	$ 396	$ 372	$ 377
Expenses:					
Depreciation	53	16	16	16	16
Operating Expenses	64	16	15	10	3
Exploration Expenses	25	25	25	25	25
Overhead	3	a	a	a	a
Interest	177	1	1	a	a
Royalty	131	46	48	45	45
Severance Taxes	76	28	27	15	15
Property Taxes	31	12	13	13	13
State Income Tax	49	23	24	24	24
Federal Income Tax	52	85	91	89	89
Profit	**$ 394**	**$ 133**	**$ 142**	**$ 140**	**$ 140**
Profit per barrel:	**$2.49**	**$1.94**	**$1.94**	**$1.89**	**$1.33**

1969 - 1972:

	1972	*1971*	*1970*	*1969*
Revenue	$ 283	$ 279	$ 278	$ 227
Expenses:				
Depreciation	16	16	17	14
Operating Expenses	3	2	1	1
Exploration Expenses	25	25	25	25
Overhead	a	a	a	a
Interest	a	a	a	a
Royalty	34	34	34	27
Severance Taxes	12	11	8	6
Property Taxes	13	10	14	13
State Income Tax	17	17	17	13
Federal Income Tax	63	63	64	50
Profit	**$ 99**	**$ 98**	**$ 100**	**$ 79**
Profit per barrel:	**$1.23**	**$1.22**	**$1.17**	**$1.04**

a. Less than $1 million

Total industry profit from production for the years 1969 through 1987 are shown in Table III-6, below. State royalty was computed in the same manner as for the Prudhoe Bay field.

Table III-6
Total Alaska Production Profit
1969 through 1987
(billions of dollars)

Production Revenue	$ 97.6
Less Expenses:	
Depreciation	8.1
Operating Expenses	5.3
Exploration Expenses	4.1
Overhead	.8
Interest	1.7
Royalty	11.8
Severance Taxes	10.4
Property Taxes	1.8
State Income Taxes	2.7
Windfall Profit Tax	6.4
Federal Income Taxes	14.3
Profit	**$ 30.2 Billion**

Profit per barrel: $4.96

As stated throughout the report, this is the best estimate available of Alaska oil industry production profit. There are, however, some questions concerning the profit numbers which are necessary to understand the possible range within which the actual profit number might fall.

Revenue Issues. As noted in Section I, revenues have been estimated based on a weighted average of all producers. The resulting revenue amount is 1.19% greater than that which would be obtained using Sohio's data alone. The question is what effect would using estimated realizations have on the reported profit numbers. Over the production history of the Alaska North Slope, approximately 50% of ANS crude was sold on the U.S. West Coast where net realizations are approximately $1.40 greater than sales on the Gulf Coast

(Barclay's, 1988, p. 3). West Coast sales have been made almost entirely by producers other than Sohio. Under this assumption, revenues would increase by $1.8 billion with a resulting increase in after-tax profit of $ 1.0 billion. This was determined by taking the estimated average realization of $17.68 for Sohio and adding the extra value of West Coast sales for 50% of production. This step indicates that this approach would yield an additional average realization of $.37 per barrel over all 4.8 billion barrels of working interest production.

A second issue related to revenues is the 1986 Arco severance tax settlement. Arco paid $243 million in this settlement. Assuming that Arco's annual report data were based on its original pricing methodology, and that the severance tax rate was 15%, this would imply that the Arco revenue data which was used in this analysis understated revenues by $1.6 billion. After allowing for 15% severance tax, 3% Alaska income tax and 34% effective Federal income tax, the net profit effect is a $.8 billion increase. Part of the settlement may have been interest, but it is also likely that the settlement rate was less than 15%. If the net effect of these two factors is to offset each other, as expected, the profit increase suggested here is supported.

An additional revenue issue is the 1988 $171 million settlement on income taxes by Arco. The extent to which this settlement affected revenues and expenses is not public information. Presumably there would be an addition to the relevant items in the Arco income statements if those statements had been prepared on the basis which Arco used for its Alaska income tax. To the extent that the financial statements relied on here are the same as that used in the tax return, profit would be understated.

It should be noted with respect to both of these settlements with Arco that they are not final settlements. The outcome of ongoing litigation and its effect on profit estimates cannot be ascertained at this time.

Depreciation Expense. For the Prudhoe Bay field, the per barrel depreciation estimates used amounted to $2.15 in 1987, $2.25 in 1986 and $1.75 in 1985. *Petroleum Intelligence Weekly* (February 1, 1988) estimates Prudhoe Bay depreciation at $2.25, $2.17 and $1.53 for those years, respectively. On average for those years, this suggests that the depreciation estimates reported here may be too high by approximately $.07 per barrel. If this is the case, depreciation for Prudhoe Bay may be overstated by $336 million over the eleven-year production history. After a 3% Alaska income tax and a 34% estimated Federal income tax, this would imply that profit is understated by $217 million.

As noted in Section II, other sources have estimated Kuparuk depreciation at up to $3.80 per barrel, which is $.89 per barrel more than the average estimate included in this report. If these other estimates are correct, this would imply that Kuparuk depreciation needs to be increased by $307 million. This would decrease Kuparuk after-tax profit by approximately $198 million.

Operating Costs. This report indicates that operating costs, including property taxes were $1.08 per barrel over the life of Prudhoe Bay field. *International Petroleum Finance* estimates these costs at $.91 per barrel. *Petroleum Intelligence Weekly* estimates them at approximately $1.03 per barrel. This suggests that the estimate in this report may be between $.05 and $.17 per barrel greater than other estimates. At $.05 per barrel, after-tax profit would increase by $153 million and at $.17 the effect would be a $522 million increase in profit.

Windfall Profit Taxes. Based on Arco's estimates, total Prudhoe Bay windfall profit tax would equal $4.6 billion. Using the U.S. Internal Revenue Service data, windfall profit tax collections for the ANS totalled $5.9 billion. The latter number was used even though the net income limitation provisions of the tax act may have served to reduce the expense. On the other hand, the data reported by Arco would have been before any settlement of audit differences. The indicated range for windfall profit tax expense is, therefore, $1.3 billion before tax and an estimated $ .8 billion after tax, subject to possible adjustments as a result of settlements. Profit reported here may, therefore, be too low by up to $ .8 billion.

Overhead. As noted in Section II, overhead included in this report was estimated at $ .8 billion for the period of Prudhoe Bay production. Had a weighted average based on Arco's and Sohio's data been used in a two-factor allocation, overhead would have increased by $ .4 billion, which translates into an approximately $ .3 billion after tax decrease in profit compared to the amounts reported here.

On the other hand, using a three-factor formula for estimating overhead based on the Arco/Sohio composite results in overhead of $ .4 billion, which is $ .4 billion less than the amount used in this report. This would imply that profit had been understated by $.3 billion after tax.

Interest Expense. Analysis of the interest costs of Arco and Sohio suggests that the differences attributable to this factor amount to less than $50 million. Since adequate data are not available and since the amount is low relative to the total profit, this analysis has not been pursued further.

Federal Income Taxes. The estimated effective tax rate for Alaska oil production for this report is 32.1%. This is equal to the $14.2 billion in income taxes divided by pre-tax income of $44.3 billion. If the Federal income taxes had

been based on the estimated 29% effective tax rate for the industry, income taxes would have decreased by $1.0 billion, with a corresponding decrease in reported profit to producers.

Using the effective tax rates for the primary Alaska oil producers given in Table II-16, the unweighted average current effective tax rate is 26.3% for 1978 to 1985. The rate is negative in 1986. Had the Federal income taxes in this report been based on the average effective rate for the producers over this eight-year period, the amount would have been $11.5 billion, which is $2.7 billion less than that included in this report. This amount would pass directly through as an increase in profit of $2.7 billion.

Summary. The questions raised in this section cannot be resolved without additional data. For this reason, the effect of the different assumptions on profit are summarized so that one can adjust the results according to their own interpretation of the data. The effect of each assumption is given in Table III-7.

Table III-7
Effect of Assumptions on Profit
(billions of dollars)

Item	Increase in Profit	Decrease in Profit
Use of West Coast prices	$ 1.0	
Arco severance tax settlement	.8	
Outside Prudhoe depreciation estimates	.2	
Outside Kuparuk depreciation estimates		$ .3
Use of *Petroleum Intelligence Weekly* operating costs	.2	
Use of *Petroleum Finance* operating costs	.5	
Use of Arco windfall profit tax data	.8	
Composite two-factor overhead		.3
Three-factor overhead	.3	
39% Federal tax rate	1.0	
Composite company rate	2.7	
Total increases	$ 7.5	
Total decreases		$ 0.6

A review of these alternative estimates indicates that the profit reported here is within a reasonable range of actual profit and is probably on the conservative side.

IV. TAPS PROFIT

GENERAL METHODOLOGY

A review of data sources on the Trans Alaska Pipeline System indicates that the annual reports filed by Sohio Pipeline Company reflect quite closely a .3334 interest in pipeline revenues and expenses. This occurs in part because nearly 100% of Sohio Pipeline Company's activities are related to TAPS. Effective tax rates were used to estimate Federal income taxes for the reasons stated above. Sohio Pipeline Company reports were available for 1978 through 1987. Due to the short production period in 1977, the pipeline probably broke even or had such a small profit or loss that it would not affect the results.[18] For 1985 through 1987, Sohio Pipeline Company provided a separate statement of TAPS revenues, costs and profit. Most of the costs were incurred jointly through Alyeska and, thus, would be shared by all pipeline owners *pro rata*. The remaining expenses appear quite close to those indicated by other observers as appropriate for TAPS in total. Operating data in Table IV-1 represent the information reported in the Sohio Pipeline Company annual reports divided by .3334. Alaska income tax estimates were based on an effective rate of 9.4% during 1978 to 1981 and an effective rate of 3% thereafter. The Federal rate was estimated in the same manner as for production.

The amounts reported in Table IV-1 were compared to other sources. Property taxes were compared to the Alaska Department of Revenue's *Revenue Sources* reference. The amounts are quite similar.

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[18] 1977 throughput would have been approximately 28% of 1978 throughput. This would imply revenues of $690 million. Operating and administrative expenses are estimated at one-half of 1978. Depreciation would probably have been proportional to throughput. Property taxes would have been the same as in 1978. Interest expense would be approximately $236 million for an estimated before-tax loss of $20 million, which is not significant relative to other revenues and expenses.

Table IV-1
TAPS Profit Projected from Sohio Pipeline Co.
(millions of dollars)

1983 through 1987:	*1987*	*1986*	*1985*	*1984*	*1983*
Revenues	$2,765	$3,080	$3,578	$3,926	$3,899
Expenses:					
Operating and Administrative	255	343	247	387	483
Depreciation	351	364	363	507	558
Property Taxes	147	164	168	171	165
Interest	150	440	411	570	579
Alaska Income Taxes	56	53	72	69	63
Federal Income Taxes	633	0	993	609	669
Profit	**$1,174**	**$1,716**	**$1,325**	**$1,614**	**$1,382**

1978 to 1982:	*1982*	*1981*	*1980*	*1979*	*1978*
Revenues	$3,896	$3,605	$3,554	$2,963	$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	549	507	591	495	417
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	61	167	154	112	54
Federal Income Taxes	795	645	645	102	9
Profit	**$1,178**	**$ 961**	**$ 842**	**$ 980**	**$ 513**

Arco reported TAPS depreciation in its 10-K's for 1981 through 1987. The amounts were factored to reflect 100% depreciation for TAPS as shown in Table IV-2. The amounts for depreciation obtained in this manner were 38% lower than the amounts obtained from the Sohio analysis. Over the life of TAPS, the depreciation estimate is based on a weighted average of the Sohio and Arco depreciation data. The weighted average is based on Arco's 22% interest in TAPS and Sohio's 33% interest. The method assumes that the missing data are equivalent to the weighted average of the data that are available. The resulting depreciation expense number is $700 million lower than it would have been using the Sohio data alone.

Table IV-2
Arco-based TAPS Depreciation Estimates
(millions of dollars)

Year	*Arco 10-K*	*Estimated Total*
1987	$ 60.0	$ 272.3
1986	60.0	272.3
1985	60.0	272.3
1984	60.0	272.3
1983	58.9	267.7
1982	57.3	260.5
1981	80.4	365.5

Reducing the depreciation estimate increases taxable profit and income taxes. Alaska income tax was increased by $34 million based over the life of TAPS. Federal income tax was increased by $204 million over the same period. Apportioning the depreciation adjustment over the life of TAPS to date results in the schedule of TAPS profit shown in Table IV-3.

Table IV-3
TAPS Profit
(millions of dollars)

1983 through 1987:

	1987	*1986*	*1985*	*1984*	*1983*
Revenues	$2,765	$3,080	$3,578	$3,926	$3,899
Expenses:					
Operating and Administrative	255	343	247	387	483
Depreciation	299	310	309	431	475
Property Taxes	147	164	168	171	165
Interest	150	440	411	570	579
Alaska Income Taxes	57	55	73	71	66
Federal Income Taxes	631	0	984	610	674
Net Profit	**$1,226**	**$1,768**	**$1,386**	**$1,686**	**$1,457**
Profit per barrel:	**$2.08**	**$3.07**	**$2.44**	**$3.17**	**$2.77**

Table IV-3 (continued)
TAPS Profit
(millions of dollars)

1978 to 1982:

	1982	*1981*	*1980*	*1979*	*1978*
Revenues	$3,896	$3,605	$3.554	$2,963	$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	467	431	503	421	355
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	63	203	162	119	60
Federal Income Taxes	802	599	617	129	8
Net Profit	**$1.250**	**$1.046**	**$ 949**	**$1.019**	**$ 570**
Profit per barrel	**$2.42**	**$2.15**	**$1.95**	**$2.49**	**$1.64**

Estimates of revenues and expenses included in this report were compared to information provided in connection with the TAPS settlement methodology. It appears from comparison with the data available to us that the revenue estimates here are approximately $400 million greater than indicated by the TAPS settlement data. The alternate estimates of operating and administrative expenses for 1978 to 1984 are within approximately $50 million. The estimates of Federal income taxes are lower in this report because the other sources used the statutory rate for tax expense purposes. Since the long-run relationship between before-tax profit and tax expense shows that the statutory rate overstates actual tax outlays, the effective rate is used in this income computations.

TAPS settlement data from Deloitte Haskins and Sells indicate that operating expenses average $.58 per barrel. The estimate in this report is $.64 per barrel. The Deloitte Haskins and Sells data indicate depreciation of $.59 per barrel. Before the Arco adjustment, the estimate in this report was $.80 per barrel. After the Arco adjustment, the estimate here is $.68 per barrel. The Federal income

tax allowance indicated from the Deloitte Haskins and Sells (DH&S) analysis of TAPS costs is $.75 per barrel. The estimate in this report is $.86 per barrel. The expense estimates used in the profit estimates reported here are consistently higher than those indicated by DH&S. Thus, profit reported here is lower than would be indicated using the DH&S data.

Barclay's de Zoete Wedd (1988) estimate cash costs of $.65 per barrel for TAPS. This would include operating and administrative costs plus property taxes. The estimate of these costs in this report is $.92 per barrel. Barclay's de Zoete Wedd estimates depreciation at $.80 per barrel, which is the same as used here after accounting for the Arco adjustment.

Petroleum Intelligence Weekly estimated that pipeline profit was $2.18 per barrel in 1985, $.64 per barrel in 1986 and $.53 per barrel in 1987. The estimates used in this report are $.75, $.94 and $.60 for each of those years respectively. Over the three-year period, they estimate a total profit of $6.1 billion. The profit reported here is $4.2 billion before the depreciation adjustment.

For the years 1983 through 1987, Arco reported the net income after tax of Arco Pipeline Inc., which holds Arco's interest in TAPS. Assuming that all of the income of Arco Pipeline is related to TAPS (which appears to be the case),[19] TAPS income for each of these years projected from the Arco Pipeline data would be $1.3 billion, $1.3 billion, $1.5 billion, $1.4 billion and $1.4 billion for a total over the five-year period of $6.9 billion. The estimate based on Sohio data is $7.2 billion. A weighted average estimate of profit based on 21.4% Arco ownership and 33.34% Sohio ownership gives a profit estimate for the four-year period for which both data series are available of $7.1 billion, which is within 2% of the estimate reported here.

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[19]TAPS income so completely dwarfs income from other pipelines that substantially all the income is attributable to TAPS.

Each of the sources which has looked into TAPS revenues, profit and costs has developed varying profit estimates. It appears that the adjusted profit indicated in Table IV-3 represent a "middle-of-the-road" estimate. Over the period of TAPS operation, estimated total profit is as follows in Table IV-4:

Table IV-4
Total Estimated TAPS Profit
(billions of dollars)

Revenues	$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
Alaska Income Tax	.9
Federal Income Tax	5.1
Profit	**$12.4 Billion**

V. OTHER INFORMATION

Downstream Profit. The profit data which have been developed in this report do not include any profits earned beyond Valdez. It has been reported elsewhere that producers may earn between $.25 and $1.00 per barrel in profits on tanker and trans-Panama canal shipping operations. These profits serve to reduce the net cost of Alaska oil landed on the U.S. West and Gulf Coasts.

There is some evidence that U.S. West Coast prices are lower because of Alaska oil production than they would be without Alaska production. This occurs because prices of crude oil on the U.S. West Coast tend to average $1.00 per barrel less than prices on the U.S. Gulf Coast. If imported crude oil had to be substituted for Alaska crude on the U.S. West Coast, prices there would be at least equal to prices on the U.S. Gulf Coast. Indeed, a substantial argument can be made that prices on the U.S. West Coast would be greater than Gulf Coast prices because shipping costs for imported crude oil would be greater f.o.b. the West Coast than the Gulf Coast. Thus, there can be additional refining profits from Alaska crude which have not been included in this analysis.

These downstream profit issues are beyond the scope of this project. They do indicate, however, that the producer's economic benefits of Alaska oil production extend beyond the profit obtained within the boundaries of the State of Alaska.

Shares. The revenues from Alaska oil and gas production and transportation go to pay for costs incurred in those activities, state taxes and royalties, federal taxes and profit to the producers. The shares of revenues received by the producers, state and federal governments are itemized in Table V-1.

Table V-1
Shares
(billions of dollars)

	Producers	*State*	*Federal Government*
Royalties		$ 11.8	
Severance taxes		10.4	
Property taxes*		3.5	
Income taxes		3.6	$ 19.4
Windfall profit taxes			6.4
Production profit	$ 30.2		
TAPS profit	12.4		
Totals	**$ 42.6**	**$ 29.3**	**$ 25.8**
Percentages	**43.6%**	**30.0%**	**26.4%**

* Includes local property taxes.

Profit as an Hourly Rate. Forty-two billion dollars is a significant number and one that is difficult to put in perspective. Relating the number to an hourly rate over 10.5 years of production (91,980 hours at 24 hours per day, 365 days per year) gives a rate of $463,144 profit received after tax.

Return on Investment. It is also possible to relate profit received by Alaska producers to the investment made in TAPS and production activities. This analysis is referred to as return on investment. The analysis compares cash flows to investments.

Investment in TAPS was an estimated $9,400 million in 1975 to 1977. The initial investment in Prudhoe Bay was an estimated $3,700 million.[20] Over time, this investment was increased as a result of infield drilling, the waterflood project and the gas miscible fluid project. The estimated total accumulated investment in Prudhoe Bay is $8,700 million. As of 1987, the investment in Kuparuk is estimated to total $4.3 billion. This includes a portion of the waterflood project which was being installed in 1987 - 1988. The investment is Milne Point was

[20]Some of these expenditures were made as early as 1969. However, more precise dates are not available for these outlays. If the $900 million in 1969 lease bonuses is accounted for as a 1969 outlay, the rate of return (assuming no debt) drops to 28.1%. Alternatively, this analysis placed no value on the ANS properties for cash flows received after 1987. Assuming that these cash flows are worth $10 billion, the rate of return (assuming no debt) increases to 31.1%. Similary adjustments would be required to the returns assuming debt.

$575 million. Lisburne had an estimated investment cost of $1,000 million and Endicott an estimated project cost of $1,000 million. A summary of the estimated investments in the ANS is given in Table V-2. These amounts are based on estimates in Arco's and Sohio's annual reports and compared to other estimates.

Table V-2
Investment Schedule
(millions of dollars)

Year	*Prudhoe*	*TAPS*	*Other ANS*	*Total*
1987	$ 720		$1,900	$2,620
1986			1,000	1,000
1985	720			720
1984			570	570
1983	2,000			2,000
1982				0
1981	1,100		3,400	4,500
1980	250			250
1979	250			250
1978				0
1977	1,850	4,700		6,550
1976	1,850	4,700		6,550

Assuming 100% equity investment, cash returns on these investments would be equal to the reported profit numbers plus depreciation and interest. This is based on the fact that if one invested 100% equity, one would incur no interest costs. Column 1 of Table V-3 shows the production profit from Table III-5. Column 2 of Table V-3 is the depreciation on production. Column 3 is the sum of profit plus depreciation. Column 4 is the interest costs. Adding the profit plus depreciation from column 3 and the interest from column 4 gives the "all-equity cash flows" from production shown in column 5 of Table V-3.

The same process was followed for TAPS which yields the data in the fifth column of Table V-4.

Table V-3
Production Cash Flows
(millions of dollars)

Year	Profit	Deprec-iation	Profit plus Deprec.	Interest	Profit, Deprec. & Interest	Explor-ation	Profit, Deprec. & Explor.
1987	$1,956	$1,394	$3,350	$192	$3,542	$288	3,638
1986	1,192	1,418	2,610	183	2,793	288	2,898
1985	3,413	1,123	4,536	183	4,719	514	5,050
1984	4,498	866	5,364	148	5,512	258	5,622
1983	3,841	779	4,620	150	4,770	818	5,438
1982	3,452	698	4,150	171	4,321	647	4,797
1981	3,610	540	4,150	18	4,168	419	4,569
1980	3,250	504	3,754	10	3,764	176	3,930
1979	3,161	345	3,506	167	3,673	174	3,680
1978	623	280	903	248	1,151	274	1,177
1977	425	53	478	177	655	25	503

Table V-4
TAPS Cash Flows
(millions of dollars)

Year	Profit	Depreciation	Profit & Deprec.	Interest	Profit, Deprec. & Interest
1987	$1,226	$ 299	$1,525	$ 150	$1,675
1986	1,768	310	2,078	440	2,518
1985	1,386	309	1,695	411	2,106
1984	1,686	431	2,117	570	2,687
1983	1,457	475	1,932	579	2,511
1982	1,250	467	1,717	648	2,365
1981	1,046	431	1,477	681	2,158
1980	949	503	1,452	720	2,172
1979	1,019	421	1,440	771	2,211
1978	570	355	925	846	1,771

The total all-equity cash flows are shown in Table V-5. The first column is the investment flow from Table V-2. The second column is the production cash flow plus interest and depreciation from Table V-3. The third column is the TAPS cash flow plus interest and depreciation from Table V-4. The last column is the sum of the production and TAPS cash flows minus the investment flows.

Table V-5
All-equity Cash Flows
(millions of dollars)

		---Cash Flows---		Net
Year	*Investment*	*Production*	*TAPS*	*Cash Flow*
1987	$2,620	$3,542	$1,675	$2,597
1986	1,000	2,793	2,518	4,311
1985	720	4,719	2,106	6,105
1984	570	5,512	2,687	7,629
1983	2,000	4,770	2,511	5,281
1982	0	4,321	2,365	6,686
1981	4,500	4,168	2,158	1,826
1980	250	3,764	2,172	5,686
1979	250	3,673	2,211	5,634
1978	0	1,151	1,771	2,922
1977	6,550	655	0	-5,895
1976	6,550	0	0	-6,550

The equivalent rate of return earned on this stream of cash flows after tax is 29.7%.

According to the Sohio annual report of 1978, approximately 75% of the investment was financed with debt. In this case, the investments in 1976 and 1977 as shown in Table V-2 would be $1,638 million net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data from columns 3 of Tables V-3 and V-4 is the profit plus depreciation. These cash flows include a deduction for interest expense. These cash flow numbers are shown in column 2 and 3 of Table V-6. Assuming that all of the cash flows were used to pay off the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978 through 1979 and all but $2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table V-6.

Table V-6
Cash Flows with 25% Equity
(millions of dollars)

		-----Cash Flow-----		Net Cash
	Investment	*Production*	*TAPS*	*Flow*
1987	$2,620	$3,350	$1,525	$2,255
1986	1,000	2,610	2,078	3,688
1985	720	4,536	1,695	5,511
1984	570	5,364	2,117	6,911
1983	2,000	4,620	1,932	4,552
1982	0	4,150	1,717	5,867
1981	4,500	4,150	1,477	1,127
1980	250	3,754	1,452	2,131
1979	250	3,506	1,440	0
1978	0	903	925	0
1977	6,550	478	0	-1,160
1976	6,550	0	0	-1,637

The rate of return implied from the stream of cash flows shown in Table V-6 is 43.7%.

REINVESTMENT RATIOS

A question of interest is the extent to which cash flows from Alaska oil and gas operations are reinvested in Alaska. Reinvestment is defined as investments in ANS projects subsequent to the initial investment in Prudhoe Bay and TAPS plus exploration costs. These amounts are shown in column 1 of Table V-7. The relevant cash flows for reinvestment analysis are the production cash flows plus exploration costs and the cash flows from TAPS. Interest costs are deducted in determining these cash flows. The production amounts are shown in the last column of Table V-3. The production cash flows are shown in column 2 of Table V-7 and the TAPS cash flows are shown in column 3 of Table V-7. The total cash flows are shown in column 4 of Table V-7. The last column of Table V-7 is the ratio of reinvestment to the cash flows.

Table V-7
Reinvestment Ratios
(millions of dollars)

Year	*Re-investment*	*----Cash Flows----* *Production*	*TAPS*	*Total*	*Reinvestment Ratio*
1987	$2,908	$3,638	$1,525	$5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%
Totals	**$15,766**			**$57,157**	

The data from Table V-7 indicate that the ANS producers are reinvesting approximately 27.8% of their cash flows in Alaska.

Appendix A
Sohio's 1982 Annual Report Disclosure

Supplementary Information on Oil and Gas Exploration, Development and Production Activities

This section provides information required by Statement of Financial Accounting Standards No. 69 (FASB 69), "Disclosures about Oil and Gas Producing Activities," which was issued in November 1982. FASB 69 aims to establish a comprehensive set of disclosures for oil and gas producing activities that replaces disclosures formerly required by either the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC), or both.

Three general disclosure areas comprise the information in this section. The first area provides historical information about costs and revenues, including the Company's aggregate recorded investment in oil and gas properties, annual costs incurred and a separate statement of the results of operations for producing activities. The second area contains the Company's petroleum engineers' quantity estimates for proved oil and gas reserves and the major factors causing changes in these reserve estimates. The final area of disclosure represents our compliance with the FASB's requirement to assign a monetary value to proved reserve quantities and changes therein using a standardized formula.

The Company has provided additional commentary throughout this section that is important for a proper understanding of the nature of the data provided and its inherent limitations.

Historical Information

Millions of Dollars	1982			1981			1980		
	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States
Capitalized Costs as of December 31									
Proved properties	$6,318	$4,182	$1,037	$3,648	$3,387	$ 461	$2,905	$2,684	$321
Unproved properties	1,296	600	[illegible]	825	136	690	499	93	406
	8,614	4,782	[illegible]	4,873	3,523	1,150	3,404	2,877	727
Accumulated depreciation, depletion and amortization	1,747	1,309	838	1,320	966	354	986	717	269
	$4,767	$3,873	$1,164	$3,553	$2,557	$ 796	$2,418	$2,160	$458
Costs Incurred (capitalized or expensed)									
Acquisition of properties	$ 626	$ 420	$ 206	$ 383	$ –	$ 383	$ 190	$ 2	$188
Exploration	418	84	332	363	98	265	144	30	114
Development	1,146	804	342	856	802	61	368	364	32

Results of Operations for Producing Activities

The following summarizes the "Results of Operations for Producing Activities" as defined by FASB 69, for the years ended December 31, 1982, 1981 and 1980. As required, financing costs are not included in this statement. Income taxes are included in the results, but were computed under FASB guidelines using statutory tax rates, while considering the effects of permanent differences and tax credits relating to oil and gas producing activities.

Millions of Dollars	1982			1981			1980		
	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States	Total	Alaska	Lower 48 States
Revenues	$6,457	$6,139	$ 268	$6,342	$6,116	$ 276	$4,496	$4,315	$181
Production costs	1,801	1,685	116	2,679	2,550	129	1,247	1,181	66
Depreciation and depletion	324	276	48	289	272	17	206	270	16
Exploration expenses									
Geological and geophysical	126	33	93	107	22	85	37	2	35
Amortization of unproved properties	163	7	156	78	8	70	64	16	53
Dry hole costs	84	6	90	124	14	110	40	13	27
Other	104	11	93	63	4	59	31	8	23
	477	57	434	370	46	324	176	38	138
	2,613	2,017	596	3,338	2,868	470	1,778	1,489	213
Income before interest and income taxes	3,794	3,122	[328]	3,004	3,248	[194]	2,718	2,826	[381]
Income taxes	1,362	1,822	[160]	1,629	1,770	[91]	1,566	1,574	[118]
	$1,432	$1,800	$ [168]	$1,375	$1,478	$ [103]	$1,232	$1,252	$ [20]

Appendix B
Barclay's de Zoete Wedd Prudhoe Bay Model (1988)

PROFITABILITY MODEL FOR PRUDHOE BAY FIELD

($/barrel)	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alaskan Crude Price*	26.48	14.07	17.37	14.01	14.50	15.23	15.99	16.79	17.62	18.51	21.28
Less:											
Tanker Freight+	(3.24)	(2.71)	(2.60)	(2.70)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
TAPS charge	(5.31)	(4.50)	(3.93)	(3.11)	(2.60)	(2.25)	(2.25)	(2.45)	(2.65)	(2.90)	(3.15)
Pipeline Loss	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)
Value at Pump Station One	17.83	6.76	10.74	8.10	8.80	9.88	10.64	11.24	11.87	12.51	15.03
Severance Tax	(2.59)	(0.68)	(1.29)	(0.97)	(1.06)	(1.19)	(1.28)	(1.35)	(1.42)	(1.50)	(1.80)
Field Operating Costs	(1.00)	(0.90)	(0.90)	(0.90)	(0.95)	(0.95)	(1.00)	(1.05)	(1.10)	(1.15)	(1.20)
Field Overheads	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.25)	(0.25)	(0.25)	(0.30)	(0.30)	(0.30)
Depreciation & Depletion	(1.60)	(2.00)	(2.00)	(2.10)	(2.20)	(2.20)	(2.30)	(2.40)	(2.40)	(2.45)	(2.45)
Ad Valorem Tax	(0.30)	(0.30)	(0.30)	(0.30)	(0.31)	(0.32)	(0.34)	(0.35)	(0.36)	(0.38)	(0.39)
Pre-tax Earnings Per Barrel	12.14	2.48	6.05	3.63	4.08	4.97	5.47	5.84	6.23	6.73	8.38
Operating Profit ($m)	3015	617	1539	934	1058	1269	1278	1257	1262	1277	1621

NOTES:

* *The Alaskan crude price is a weighted averaged of the prices received for sales on the West and Gulf Coasts; Gulf Coast sales normally fetch around $1/barrel more than those on the West Coast. We assume 1/3 of sales are made on the West Coast with the balance on the Gulf.*

\+ *Tanker freight is again a weighted average of the rate for deliveries from Valdez to the West and Gulf Coasts. Because shipping costs to the Gulf Coast are normally some $2.40/barrel higher, sales on the West Coast are more profitable to BP despite the fact that the crude oil commands a lower price than on the Gulf (see Section 5 below). In 1989 we have assumed that tanker costs rise by around 50c/barrel due to an increase in the use of expensive to operate Jones Act vessels (see Section 5), partly offset by a 70,000 barrel/day increase in shipments by pipeline from the West to Gulf Coasts (which is some 60c/barrel cheaper than transport by ship via Panama).*

Appendix C
Salomon Brothers' Arco Alaska Profits Model (1987)

Figure 5. Atlantic Richfield Company — Actual and Projected Alaskan Production Earnings, 1988-92E
(Dollars Per Barrel Unless Otherwise Indicated)

	1988	1989	1990E	1991E	1992E	1993E	1994E	1995E
Prudhoe Bay Field								
Selling Price — West Texas Intermediate Crude	$20.00	$15.75	$17.50	$20.00	$22.00	$24.00	$25.00	$26.00
Prudhoe Bay Field Crude Price[a]	14.00	11.20	12.90	14.75	16.25	17.75	18.50	19.25
Transportation Deductions								
Valdez to U.S. Gulf Coast	$4.90	$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge	3.28	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equals Prudhoe Bay Field Wellhead Price	$5.82	$3.65	$5.15	$7.15	$8.75	$10.35	$11.00	$11.65
Production Expenses								
Severance Tax	$1.30	$1.50	$1.50	$1.58	$1.88	$2.13	$2.25	$2.38
Windfall Profit Tax	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Field Operating Expenses	0.90	0.75	0.80	0.85	0.90	0.95	0.95	1.00
Depreciation and Depletion	1.60	1.75	1.80	1.85	1.90	1.95	2.00	2.05
Unit Operating Profit	$2.15	$2.65	$5.05	$7.42	$9.09	$10.72	$11.45	$12.09
Prudhoe Net Production (mb/d)	308.5	307.1	307.0	308.0	308.0	285.0	266.0	245.0
Prudhoe Operating Profit (Dollars in Millions)	$1,388	$297	$566	$834	$1,022	$1,116	$1,112	$1,081
Kuparuk River Field								
Kuparuk River Field Crude Price in U.S. Gulf	$20.60	$15.05	$16.70	$19.10	$21.00	$22.00	$23.00	$24.05
Transportation Deductions								
Valdez to U.S. Gulf Coast	$4.50	$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge	3.28	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Kuparuk River Spur Line Charge	0.87	0.85	0.85	0.65	0.65	0.85	0.85	0.85
Equals Kuparuk Field Wellhead Price	11.15	5.65	8.30	10.85	12.85	14.05	15.75	16.60
Production Expenses								
Severance Tax	$1.30	$0.45	$0.85	$0.85	$1.05	$1.20	$1.25	$1.35
Field Operating Expenses	2.50	1.85	1.85	1.80	1.85	1.90	1.95	2.00
Depreciation and Depletion	3.75	3.55	3.55	3.65	3.75	3.85	3.90	4.00
Unit Operating Profit	$3.60	$0.20	$2.45	$4.55	$6.20	$7.90	$8.65	$9.25
Kuparuk Net Production (mb/d)	94.9	109.9	110.0	110.0	110.0	110.0	110.0	110.0
Kuparuk Operating Profit (Dollars in Millions)	$298	$8	$98	$183	$249	$317	$347	$371
Lisburne Formation								
Lisburne Formation Crude Price in U.S. Gulf[a,b]		$14.95	$16.65	$19.00	$20.90	$22.80	$23.75	$24.70
Transportation Deductions								
Valdez to U.S. Gulf Coast		$3.80	$3.85	$4.10	$4.25	$4.40	$4.50	$4.60
TransAlaska Pipeline Charge		4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equals Lisburne Wellhead Price		6.40	8.90	11.40	13.40	15.40	16.25	17.10
Production Expenses								
Severance Tax		$0.64	$0.90	$1.15	$1.35	$1.55	$1.65	$1.70
Field Operating Expenses		2.70	2.75	2.75	2.85	2.90	3.00	3.10
Depreciation and Depletion		6.00	6.00	6.00	6.00	6.00	6.00	6.00
Unit Operating Profit		$(2.94)	$(0.75)	$1.50	$3.20	$4.95	$5.60	$6.30
Lisburne Net Production (mb/d)		4.1	15.0	20.0	30.0	35.0	40.0	40.0
Lisburne Operating Profit (Dollars in Millions)		$(4)	$(41)	$11	$35	$63	$82	$92
Total Alaskan Operating Profits Before Exploration Expenses (Dollars in Millions)	$1,686	$301	$660	$1,028	$1,306	$1,496	$1,541	$1,544
MEMO: Net Alaskan Crude Oil Production (mb/d)	403.4	421.3	432.0	438.0	448.0	430.0	410.0	395.0

[a] Assumed prices of Prudhoe Bay, Kuparuk River and Lisburne field oil production tied to the forecast prices of West Texas intermediate grade oil, based on the historical relationships of those crude prices to the WTI crude prices.
[b] Lisburne production began in the fourth quarter of 1988.
Mb/d: Thousands barrels per day. E: Estimate.

Appendix D

Alaska Oil Industry Development Time Line

1954 - BLM issues 272 oil and gas leases.

1957 - Swanson River oil discovered.

1962 - Cook Inlet oil discovered (Middle Ground Shoals)

1965 - Three additional Cook Inlet oil fields discovered (Granite Point, McArthur River, Trading Bay)

1967 - Prudhoe Bay oil is discovered. With over 10 billion barrels of reserves, it is a "super-giant" and the largest oil field in North America.

- Middle Ground Shoals, Granite Point and Trading Bay begin production.

1969 - Prudhoe Bay lease sale.

- Kuparuk River oil discovered. With a billion barrels of reserves it is a "giant" and is second only to Prudhoe Bay as the most productive field in the United States and Canada.

1977 - Prudhoe Bay oil Begins flowing to Valdez through Trans-Alaska Pipeline System (TAPS).

1978 - Endicott oil discovered.

1985 - Milne Point begins production.

1986 - Lisburne begins production.

- Kuparuk production peaks at 300,000 barrels per day.

1987 - Endicott begins production.

- Milne Point shuts down.

Appendix E

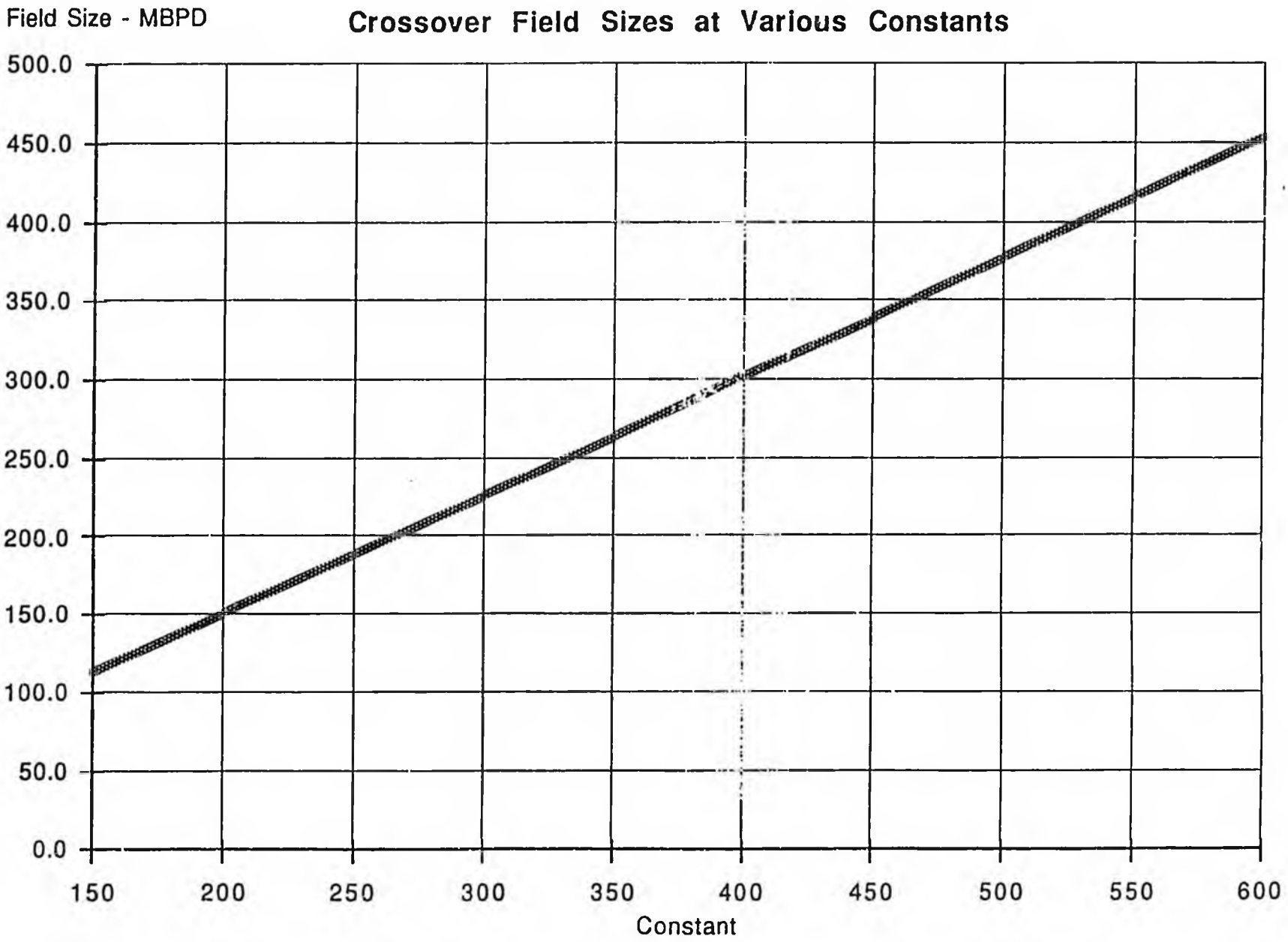
Total ANS Production and TAPS Profits
1977 through 1987
(millions of dollars)

1982 - 1987

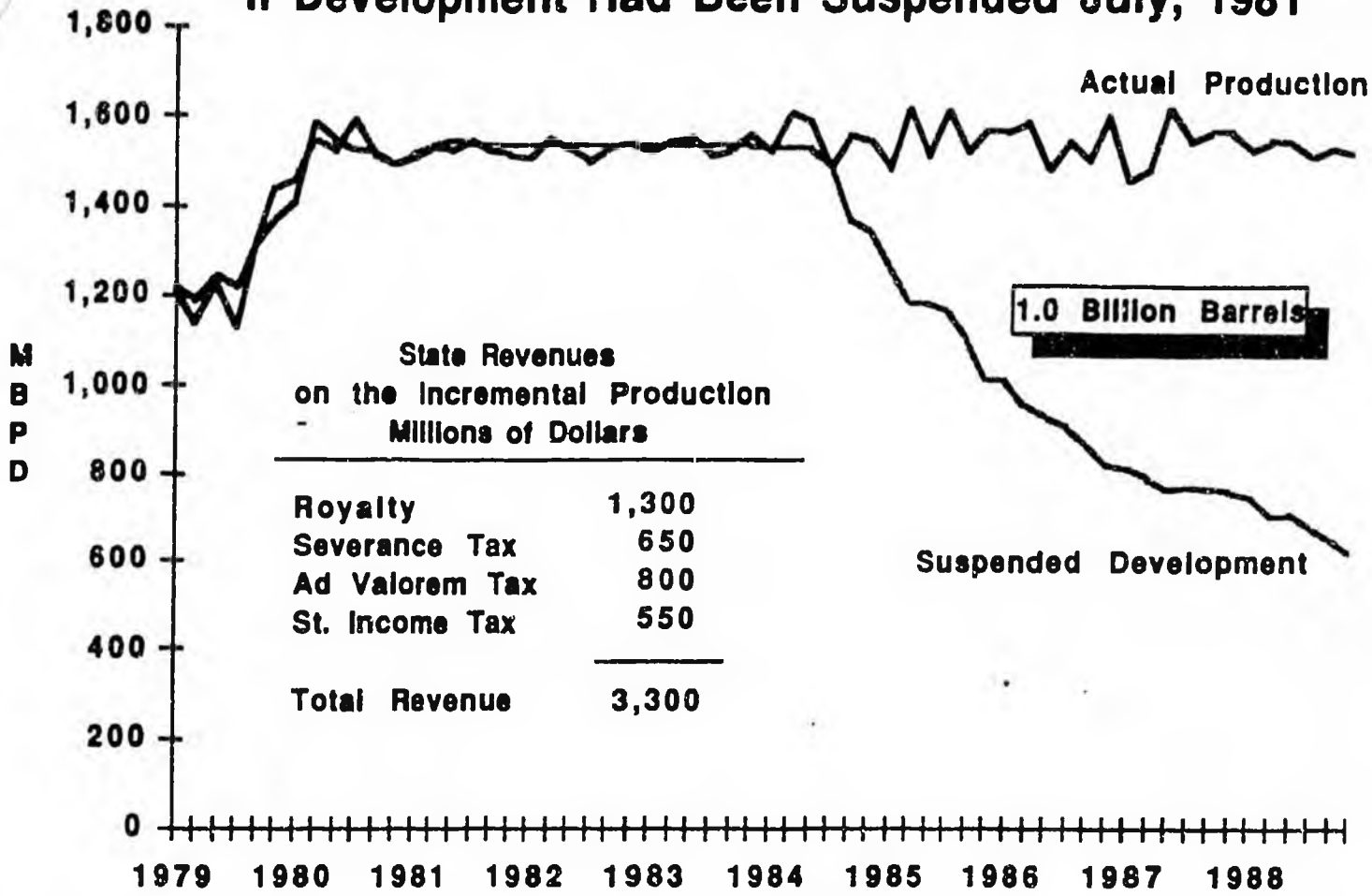
	1987	*1986*	*1985*	*1984*	*1983*	*1982*
Revenue	10393	8051	14707	14790	14685	15758
Expenses:						
Depreciation	1636	1674	1386	1258	1219	1131
Operating Expenses	1169	967	907	1065	954	1080
Overhead	129	124	164	100	104	84
Interest	328	611	585	709	719	807
Royalty	900	587	1316	1291	1283	1413
Severance Taxes	872	623	1403	1395	1388	1536
Property Taxes	341	353	353	339	329	329
State Income Taxes	150	94	257	253	248	239
Windfall Profit Taxes			39	211	426	1375
Federal Income Taxes	1653	0	3443	2170	2532	3031
Profits	**3215**	**3018**	**4854**	**5999**	**5483**	**4733**
Profit ($ per barrel)	**5.45**	**5.23**	**8.54**	**11.27**	**10.43**	**9.14**

1977 - 1981

	1981	*1980*	*1979*	*1978*	*1977*
Revenue	16935	13095	8855	4243	717
Expenses:					
Depreciation	941	979	741	609	38
Operating Expenses	1020	617	514	538	46
Overhead	51	15	2	0	2
Interest	698	730	927	1049	117
Royalty	1596	1143	706	221	86
Severance Taxes	1291	924	622	195	76
Property Taxes	317	314	297	278	30
State Income Taxes	872	712	486	127	30
Windfall Profit Taxes	3089	797			
Federal Income Taxes	2570	2703	512	17	32
Profits	**4490**	**4161**	**4048**	**1209**	**260**
Profit ($ per barrel)	**9.24**	**8.56**	**9.88**	**3.47**	**2.58**


Field Size - MBPD
Crossover Field Sizes at Various Constants
500.0
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
150
200
250
300
350
400
450
500
550
600
Constant

Prudhoe Bay Production
If Development Had Been Suspended July, 1981



State Revenues
on the Incremental Production
Millions of Dollars

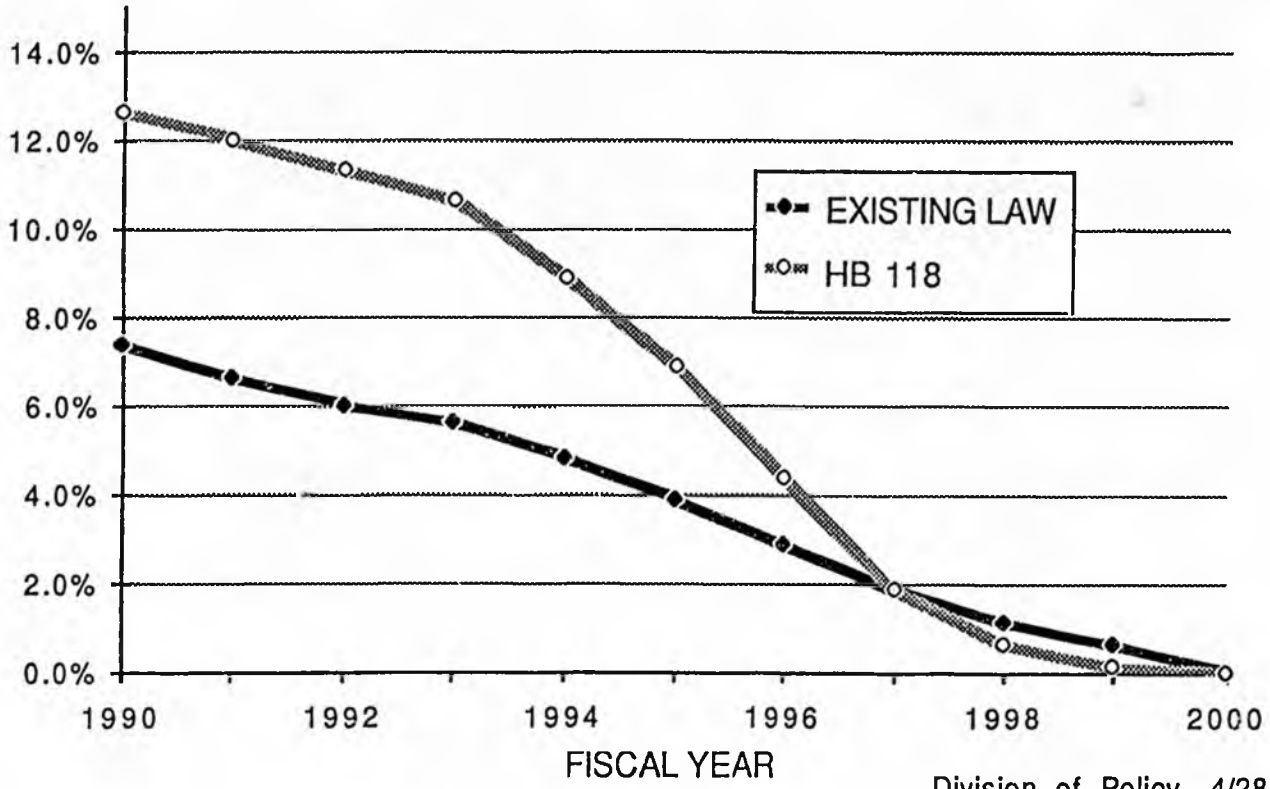
Royalty	1,300
Severance Tax	650
Ad Valorem Tax	800
St. Income Tax	550
Total Revenue	3,300

Prudhoe Bay
1981-1988 Industry Investment

		$ MM
Additional Wells		2,550
Producing Wells	450	
Injection Wells	123	
Other Wells	23	
Waterflood		2,099
Production Facilities		1,475
Gas Handling		470
Enhanced Oil Recovery		620
Other		820
Total		$8,040

Figure 2

PROJECTED TAX RATES AT KUPARUK



Division of Policy, 4/28/89

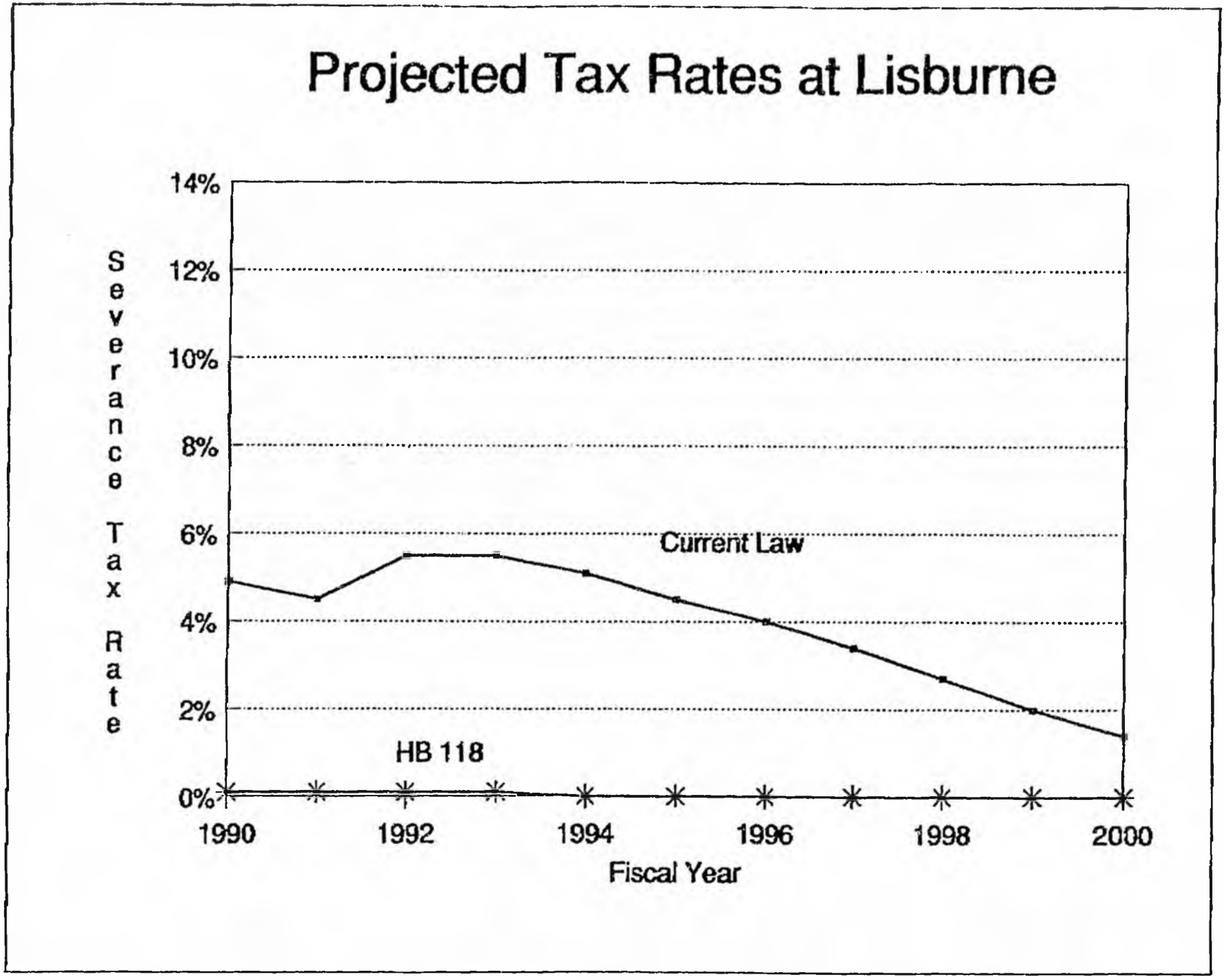
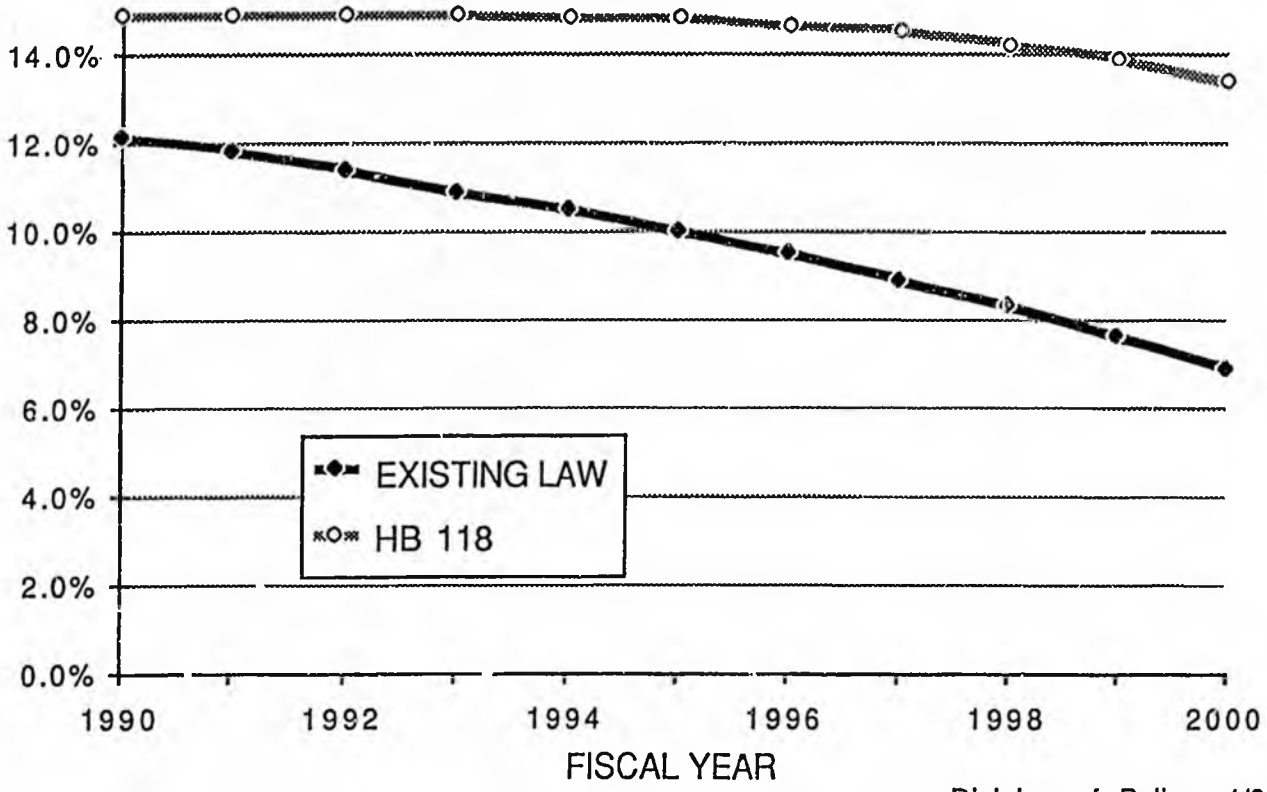


Figure 1

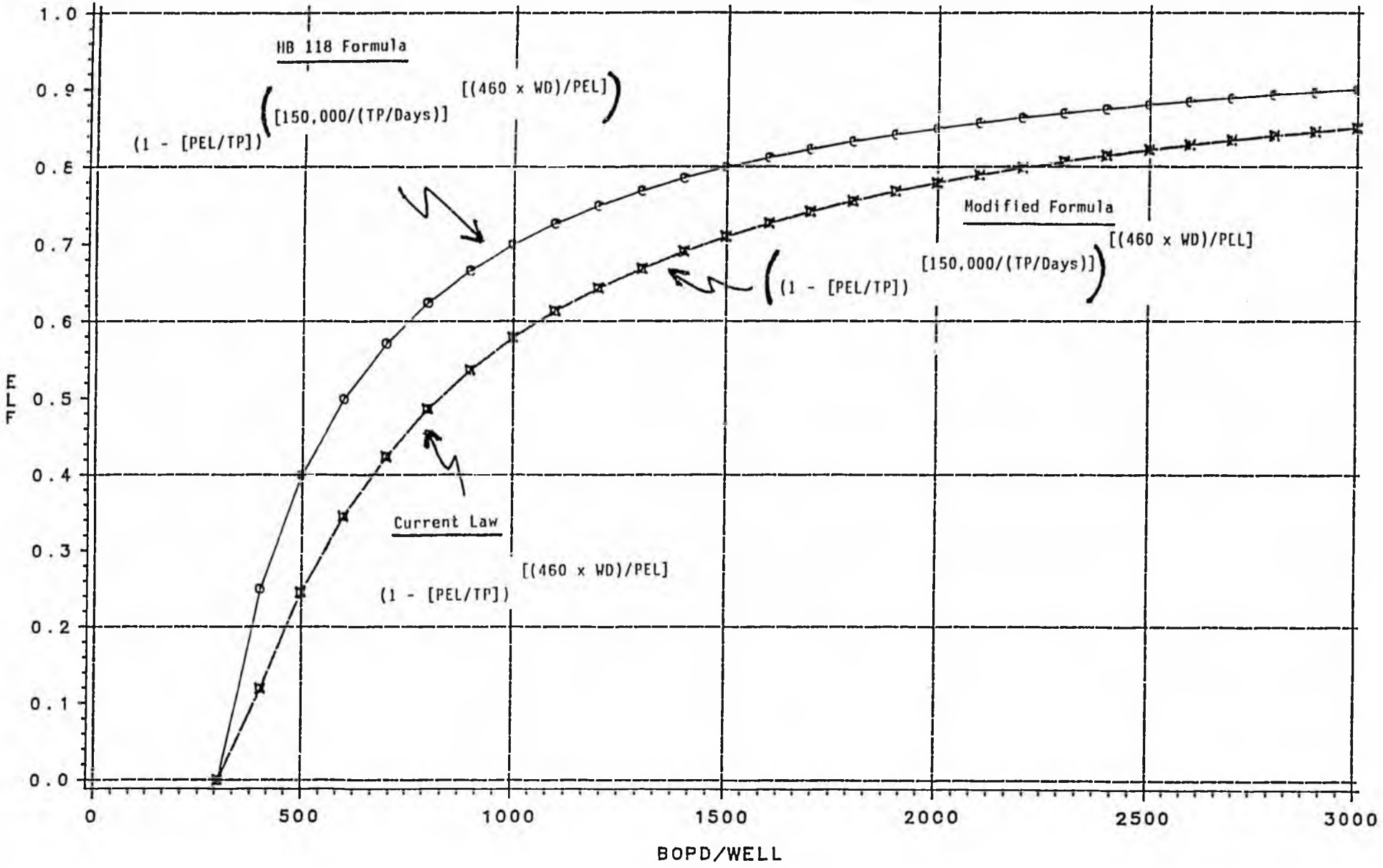
PROJECTED TAX RATES AT PRUDHOE BAY



Division of Policy, 4/28/89

HB 118 – ELF FORMULA SENSITIVITIES

150,000 BOPD FIELD

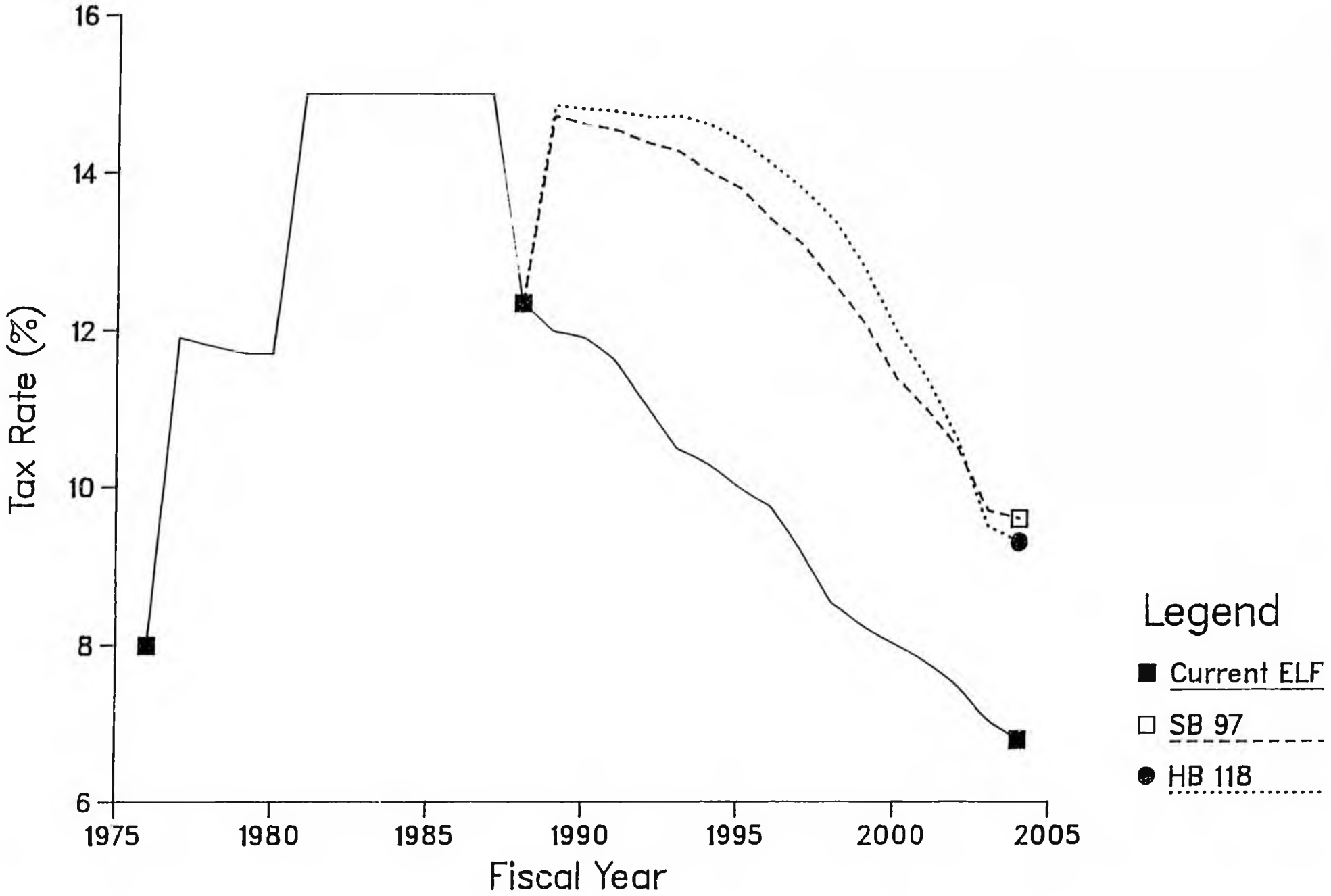


X X X X X CURRENT TAX
o o o o oHB118 FORMULA
¤ ¤ ¤ ¤ ¤MOD FORMULA

HOUSE FINANCE COMMITTEE
03-16-89
B.V. LIDDELL

PBU Historical and Projected Tax Rate

Includes SB 97 and HB 118 Impacts



B. V. Liddell
4-23-89

INCREMENTAL SEVERANCE TAX EXAMPLE 20-Apr-89

KUPARUK EXAMPLE

THE ADDITION OF 1 WELL PRODUCING AT THE AVERAGE RATE

ACTUAL DEC'88 FIGURES

	CURRENT LAW		HB-118	
	BASE	+1 WELL	BASE	+1 WELL
PRODUCTION MBPD	307.2	308.1	307.2	308.1
TOTAL PRODUCTION MBL/MO	9,522.37	9,552.27	9,522.37	9,552.27
WELLS	318	319	318	319
BBL/DAY/WL	965	965	965	965
ELF	0.564894	0.564894	0.883291	0.883817
EFFECTIVE TAX RATE	8.4734%	8.4734%	13.2494%	13.2573%
TOTAL FIELD TAX M$	4,165.46	4,178.55	6,513.28	6,537.63
TOTAL FIELD TAX $/BBL	0.500	0.500	0.782	0.782
INCREASE IN TAX $M		13.08		24.35
INCREASE IN MBBLS		26.17		26.17
INCREMENTAL SEVERANCE TAX $/BBL		0.500		0.930

ARCO Kuparuk Example

	Current Law	Proposed Law
Change in Annual Gross Revenue	$981,000	$981,000
Change in Annual Severance Tax	($37,846)	$58,611
Tax Rate on Incremental Production	-3.9%	6.0%
Average Tax Rate Before Drilling	7.820%	10.944%
Average Tax Rate After Drilling	7.806%	10.938%
Percent Change in Average Tax Rate Due to Drilling	-0.180%	-0.055%

[illegible] of Price, [illegible]

CURRENT LAW

Field Rate x Wellhead Price x Severance Tax x ELF

90,168,000 BOPY x $/BBO x 0.15 x 0.85134

= $63,461,000/year

Addition of 1 well:

90,277,000 BOPY x $/BBO x 0.15 x 0.8504

=$63,433,305/year

A decrease of $37,846 year

PROPOSED LAW

Field Rate x Wellhead Price x Severance Tax x ELF

90,168,000 BOPY x $/BBO x 0.15 x 0.7500

=$58,88,273/year

Addition of 1 well:

90,277,000 BOPY x $/BBO x 0.15 x 0.7238

=$58,578,464/year

An increase of $58,611 year

[Copy of ARCO Handout, March 27, 1987]

"a $38,000 tax break for the oil industry, is that a good thing for Alaska ?"

The Administration says, No.

For the citizens of Alaska, as Royalty Owners, the answer is definitely , Yes !

The Rest of the Story on the ARCO Drilling Example

	Without Royalty	Including Royalty	Royalty
Original Kuparuk bbl / Yr.	90,168,000	103,049,143	12,881,143
With New Well	90,277,000	103,173,714	12,896,714
		Additional Royalty	15,571
		x $9.00 / bbl	$140,143
		+ Ad Valorem Tax	$20,000
		- ELF Impact	($37,846)
		Total State Revenue Impact	**$122,297**

Kuparuk River Field	Net Pay Feet	Gross Reserves MMBL
Kuparuk Maximums	70-80	60.9
Current Kuparuk Developed Area Average	55	42.7
Remaining Drill Site Development Areas		
Drill Site 1 K	25	8.9
Drill Site 1 M	10	12.8
Drill Site 1 J	25	6.2
Drill Site 2 K	20	22.6
Drill Site 2 M	25	32.3
Drill Site 2 L	15	21.5
Drill Site 2 P	15	11.8
Drill Site 3 G	15	22.7
Drill Site 3 R	25	13.2
Drill Site 3 L	25	15.7
Total		167.6
Average		16.8

PROJECT PORTFOLIO

KUPARUK

Project	Description	Timing
Drilling		
• Peripheral Drillsite 2K	Selective peripheral DS development	1989 SU
• Peripheral Drillsite 3R	on 160 acre spacing. Total of 98	1989 SU
• Peripheral Drillsite 2M	additional wells	1990 SU
• Peripheral Drillsite 2L		1990 SU
• Peripheral Drillsite 3G		1990 SU
• Rem. Peripheral Dev.	14 drillsite expansions, 6 new drillsites, 180 additional wells 1 rig 1989, 2 rigs thereafter	1990===>
Waterflood/EOR		
• LIP-3 Expansion	Additional water handling capacity @ CPF-3	1990 SL
• Infill Drill @ DS 1Y/2Z	22 new wells. Improve EOR efficiency	1989===>
• Infill Drill @ DS 1A	16 wells. Seed for Phase I infill	1989 SU
• Phase I Infill Drilling	160 + 80 acre accelerate reserves	1991 SU
• Fullfield EOR	19 drillsites staged over 4 years	1991 SU

ANS Net Revenue

	Kuparuk $/bbl	Kuparuk $/bbl	Kuparuk $/bbl
Assumed Crude Price	**13.42**	**16.41**	**18.96**
Tanker Freight	2.70	2.70	2.70
Quality Differential	0.40	0.40	0.40
TAPS Tariff	3.11	3.11	3.11
Kuparuk Pipeline	0.70	0.70	0.70
Pipeline Loss	0.10	0.10	0.10
Wellhead Price	6.41	9.40	11.95
Production Cost and Capital Recovery	5.43	5.43	5.43
Total Net Revenue	0.99	3.98	6.53
State Royalty	0.75	1.12	1.44
Severance Tax	0.50	0.73	0.92
Property Tax	0.44	0.44	0.44
State Income Tax	-0.02	0.05	0.11
Total State	1.66	2.34	2.91
Federal Income Tax	-0.23	0.56	1.23
Producer Profit	-0.45	1.08	2.38

Source:
Barclays de Zoete Wedd, September 1988
Alaska Department of Revenue October 1988
State of Alaska Royalty and Severance Methodology

ANS Net Revenue Under HB-118

	Kuparuk $/bbl	Kuparuk $/bbl	Kuparuk $/bbl
Assumed Crude Price	**13.42**	**16.41**	**18.96**
Tanker Freight	2.70	2.70	2.70
Quality Differential	0.40	0.40	0.40
TAPS Tariff	3.11	3.11	3.11
Kuparuk Pipeline	0.70	0.70	0.70
Pipeline Loss	0.10	0.10	0.10
Wellhead Price	6.41	9.40	11.95
Production Cost and Capital Recovery	5.43	5.43	5.43
Total Net Revenue	0.99	3.98	6.53
State Royalty	0.75	1.12	1.44
Severance Tax	0.75	1.10	1.40
Property Tax	0.44	0.44	0.44
State Income Tax	-0.03	0.04	0.10
Total State	1.91	2.70	3.37
Federal Income Tax	-0.31	0.43	1.07
Producer Profit	-0.61	0.84	2.08

Source:
Barclays de Zoete Wedd, Septer
Alaska Department of Revenue I
State of Alaska Royalty and Seve

3.50 - Capital recovery
2.00 production cost.

SB 97 and HB 118 ELFs COMPARED

An analysis prepared for the
Senate Special Committee on Oil and Gas
20 April 1989

As the chair requested, this analysis focuses on three fields -- Prudhoe, Kuparuk and Lisburne -- and the differences between SB 97 and HB 118.

ELF formulas in both SB 97 and HB 118 have two variables: productivity per well, and total productivity (or, field productivity). In the real world these variables are closely interrelated; both are subject to continuous change over the life of an oil field. Figure 1 illustrates what realistically will happen when the two variables are considered together. Figure 2 illustrates what happens if total production is hypothetically held constant and per-well productivity is varied. Figure 3 hypothetically holds per-well productivity constant for the three fields, and illustrates the severance tax rates that would result when the total production is varied. The declining tax rates illustrated in Figure 1 are depicted graphically in Figures 4-6.

Figure 7 shows the declining total production and per-well productivity projected for the three fields, and which underly the rates in Table 1.

As requested, step-by-step instructions for calculating the ELFs under the two bills are included following Figure 7.

Division of Policy and Department of Revenue.

The Economic Limit Factor or ELF is a fraction which reduces severance taxes as well productivity declines.

EFFECTIVE SEVERANCE TAX RATE equals nominal severance tax rate times ELF.

For example, 15.00% times 0.824 equals an effective severance tax rate of 12.36%.

Department of Revenue (April 20, 1989)

Figure 1

PROJECTED SEVERANCE TAX RATES, FY 1990-2000
UNDER EXISTING LAW, SB 97, AND HB 118

Fiscal Year	PRUDHOE			KUPARUK			LISBURNE		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
1990	12.1%	14.7%	14.9%	7.4%	11.1%	12.6%	5.4%	1.3%	0.4%
1991	12.0%	14.7%	14.9%	6.6%	10.4%	12.0%	4.7%	0.7%	0.1%
1992	11.8%	14.6%	14.9%	6.0%	9.6%	11.3%	5.7%	0.9%	0.2%
1993	11.4%	14.5%	14.9%	5.6%	8.9%	10.6%	5.7%	0.9%	0.2%
1994	11.1%	14.4%	14.8%	4.8%	7.3%	8.9%	5.4%	0.6%	0.1%
1995	10.5%	14.2%	14.8%	3.9%	5.5%	6.9%	4.4%	0.2%	0.0%
1996	9.7%	14.0%	14.6%	2.9%	3.6%	4.4%	4.0%	0.1%	0.0%
1997	8.9%	13.6%	14.5%	1.9%	1.7%	1.9%	3.5%	0.0%	0.0%
1998	7.9%	13.2%	14.2%	1.1%	0.6%	0.6%	2.9%	0.0%	0.0%
1999	6.8%	12.6%	13.9%	0.6%	0.2%	0.1%	1.3%	0.0%	0.0%
2000	5.6%	11.9%	13.4%	0.0%	0.0%	0.0%	1.4%	0.0%	0.0%

Division of Policy, 4/19/89

Figure 2

HYPOTHETICAL SEVERANCE TAX RATES RESULTING WHEN FIELD PRODUCTION IS HELD CONSTANT AND AVERAGE DAILY PRODUCTION PER WELL IS VARIED--UNDER EXISTING LAW, SB 97, AND HB 118

(Approximate FY 90 averages shown in highlighting.)

Average Daily Production Per Well	PRUDHOE 1,452,100 barrels per day			KUPARUK 279,500 barrels per day			LISBURNE 43,800 barrels per day		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
300	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
325	0.3%	10.9%	13.9%	0.3%	2.8%	5.6%	0.2%	0.0%	0.0%
350	0.8%	11.7%	14.1%	0.8%	4.2%	7.1%	0.6%	0.0%	0.0%
375	1.3%	12.2%	14.3%	1.3%	5.2%	8.1%	1.0%	0.0%	0.0%
400	1.8%	12.6%	14.4%	1.8%	6.0%	8.8%	1.5%	0.0%	0.0%
500	3.7%	13.4%	14.6%	3.7%	8.2%	10.5%	3.0%	0.3%	0.0%
600	5.2%	13.7%	14.7%	5.2%	9.5%	11.5%	4.2%	0.7%	0.1%
700	6.4%	14.0%	14.7%	6.4%	10.4%	12.1%	5.2%	1.2%	0.3%
800	7.3%	14.1%	14.8%	7.3%	11.0%	12.5%	6.0%	1.7%	0.6%
900	8.1%	14.3%	14.8%	8.1%	11.5%	12.8%	6.6%	2.2%	0.8%
1,000	8.7%	14.3%	14.8%	8.7%	11.9%	13.1%	7.1%	2.8%	1.2%
1,100	9.2%	14.4%	14.9%	9.2%	12.2%	13.3%	7.5%	3.2%	1.5%
1,200	9.6%	14.5%	14.9%	9.6%	12.4%	13.4%	7.9%	3.7%	1.8%
1,300	10.0%	14.5%	14.9%	10.0%	12.6%	13.6%	8.2%	4.1%	2.2%
1,400	10.4%	14.6%	14.9%	10.4%	12.8%	13.7%	8.5%	4.5%	2.5%
1,500	10.7%	14.6%	14.9%	10.7%	13.0%	13.8%	8.7%	4.8%	2.8%
1,600	10.9%	14.6%	14.9%	10.9%	13.1%	13.8%	8.9%	5.1%	3.1%
1,700	11.1%	14.6%	14.9%	11.1%	13.2%	13.9%	9.1%	5.4%	3.4%
1,800	11.3%	14.7%	14.9%	11.3%	13.3%	14.0%	9.3%	5.7%	3.7%
1,900	11.5%	14.7%	14.9%	11.5%	13.4%	14.0%	9.4%	6.0%	3.9%
2,000	11.7%	14.7%	14.9%	11.7%	13.5%	14.1%	9.5%	6.2%	4.2%
2,100	11.8%	14.7%	14.9%	11.8%	13.6%	14.1%	9.7%	6.4%	4.4%
2,200	12.0%	14.7%	14.9%	12.0%	13.6%	14.2%	9.8%	6.6%	4.7%
2,300	12.1%	14.7%	14.9%	12.1%	13.7%	14.2%	9.9%	6.8%	4.9%
2,400	12.2%	14.7%	14.9%	12.2%	13.7%	14.2%	10.0%	7.0%	5.1%

Division of Policy, 4/19/89

Figure 3

HYPOTHETICAL SEVERANCE TAX RATES RESULTING WHEN PER-WELL PRODUCTIVITY IS HELD CONSTANT AND AVERAGE DAILY PRODUCTION PER FIELD IS VARIED--UNDER EXISTING LAW, SB 97, AND HB 118

(Approximate FY 90 averages shown in highlighting.)

Average Daily Production for the Field	PRUDHOE 2,290 barrels per well per day			KUPARUK 817 barrels per well per day			LISBURNE 730 barrels per well per day		
	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118	Existing Law	SB-97	HB-118
10,000	12.1%	1.1%	0.0%	7.4%	0.0%	0.0%	5.4%	0.0%	0.0%
20,000	12.1%	4.1%	0.7%	7.4%	0.2%	0.0%	5.4%	0.1%	0.0%
30,000	12.1%	6.4%	2.9%	7.4%	0.9%	0.1%	5.4%	0.5%	0.0%
40,000	12.1%	7.9%	5.2%	7.4%	1.8%	0.5%	5.4%	1.1%	0.2%
50,000	12.1%	9.0%	7.0%	7.4%	2.8%	1.3%	5.4%	1.8%	0.7%
60,000	12.1%	9.8%	8.5%	7.4%	3.7%	2.3%	5.4%	2.4%	1.4%
70,000	12.1%	10.4%	9.5%	7.4%	4.5%	3.4%	5.4%	3.1%	2.2%
80,000	12.1%	10.9%	10.4%	7.4%	5.3%	4.5%	5.4%	3.6%	3.1%
90,000	12.1%	11.3%	11.0%	7.4%	5.9%	5.5%	5.4%	4.2%	3.8%
100,000	12.1%	11.6%	11.5%	7.4%	6.5%	6.4%	5.4%	4.6%	4.6%
200,000	12.1%	13.2%	13.7%	7.4%	9.9%	11.2%	5.4%	7.5%	8.7%
300,000	12.1%	13.8%	14.3%	7.4%	11.3%	12.8%	5.4%	8.9%	10.2%
400,000	12.1%	14.1%	14.5%	7.4%	12.2%	13.5%	5.4%	9.6%	10.9%
500,000	12.1%	14.2%	14.7%	7.4%	12.7%	14.0%	5.4%	10.1%	11.3%
600,000	12.1%	14.4%	14.8%	7.4%	13.0%	14.2%	5.4%	10.4%	11.5%
700,000	12.1%	14.5%	14.8%	7.4%	13.3%	14.4%	5.4%	10.7%	11.7%
800,000	12.1%	14.5%	14.8%	7.4%	13.5%	14.5%	5.4%	10.9%	11.8%
900,000	12.1%	14.6%	14.9%	7.4%	13.7%	14.6%	5.4%	11.0%	11.8%
1,000,000	12.1%	14.6%	14.9%	7.4%	13.8%	14.6%	5.4%	11.1%	11.9%
1,100,000	12.1%	14.7%	14.9%	7.4%	13.9%	14.7%	5.4%	11.2%	11.9%
1,200,000	12.1%	14.7%	14.9%	7.4%	14.0%	14.7%	5.4%	11.3%	12.0%
1,300,000	12.1%	14.7%	14.9%	7.4%	14.1%	14.8%	5.4%	11.4%	12.0%
1,400,000	12.1%	14.7%	14.9%	7.4%	14.1%	14.8%	5.4%	11.4%	12.0%
1,500,000	12.1%	14.7%	14.9%	7.4%	14.2%	14.8%	5.4%	11.5%	12.1%
1,600,000	12.1%	14.8%	14.9%	7.4%	14.2%	14.8%	5.4%	11.5%	12.1%

Division of Policy, 4/19/89.

Figure 4

PROJECTED TAX RATES AT PRUDHOE BAY

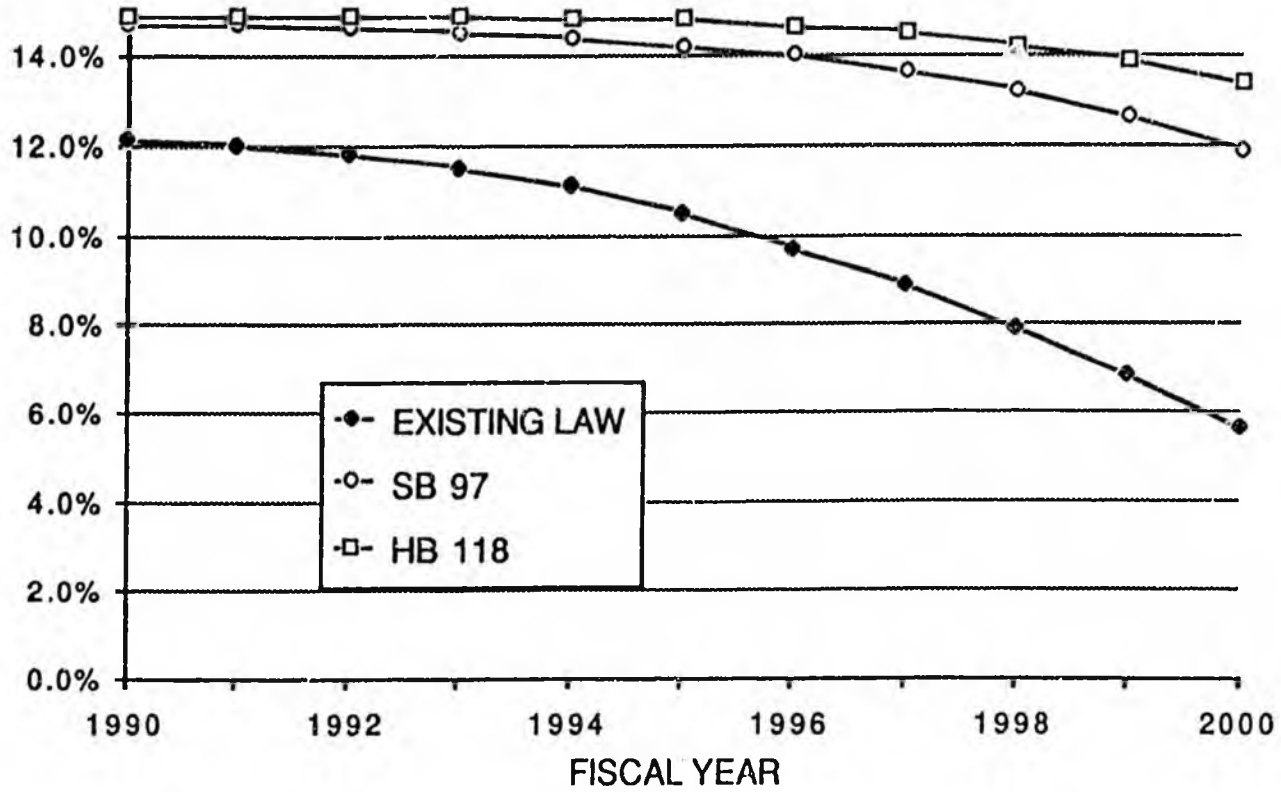


Figure 5

PROJECTED TAX RATES AT KUPARUK

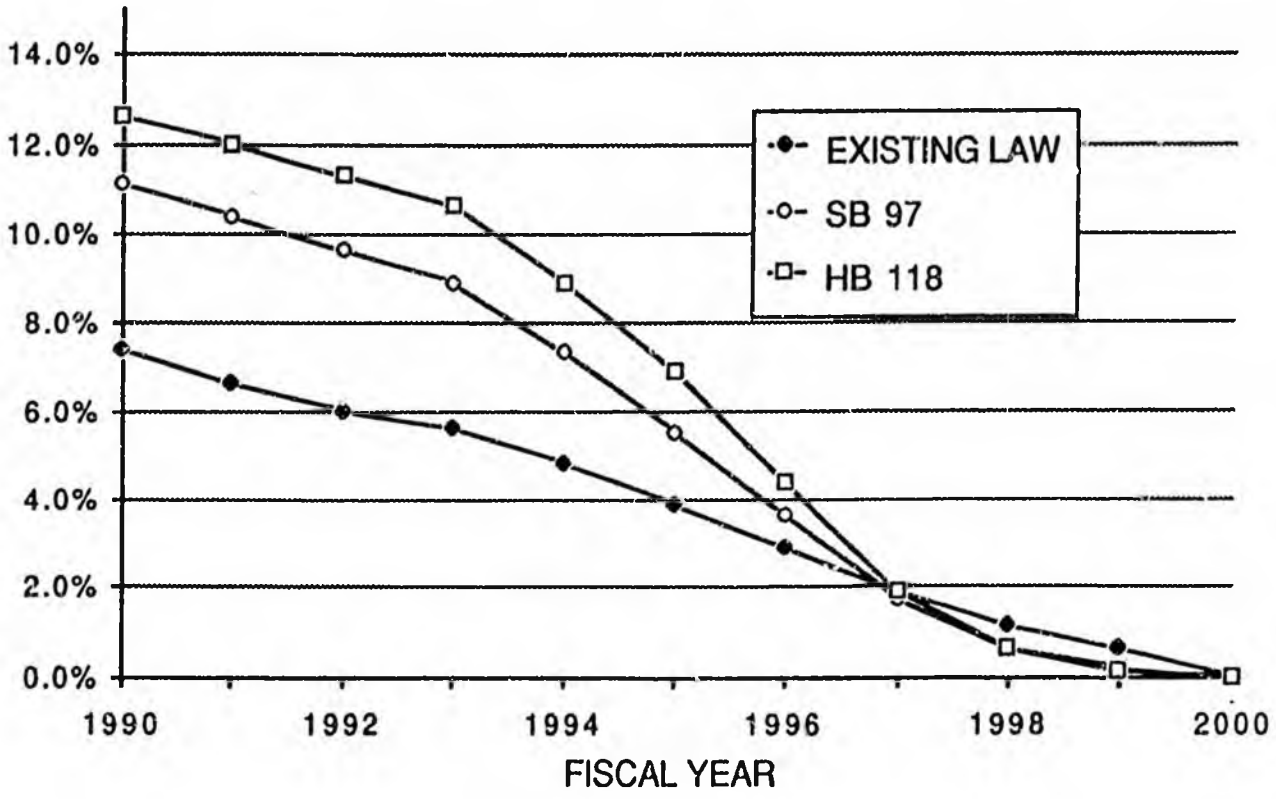


Figure 6

PROJECTED TAX RATES AT LISBURNE

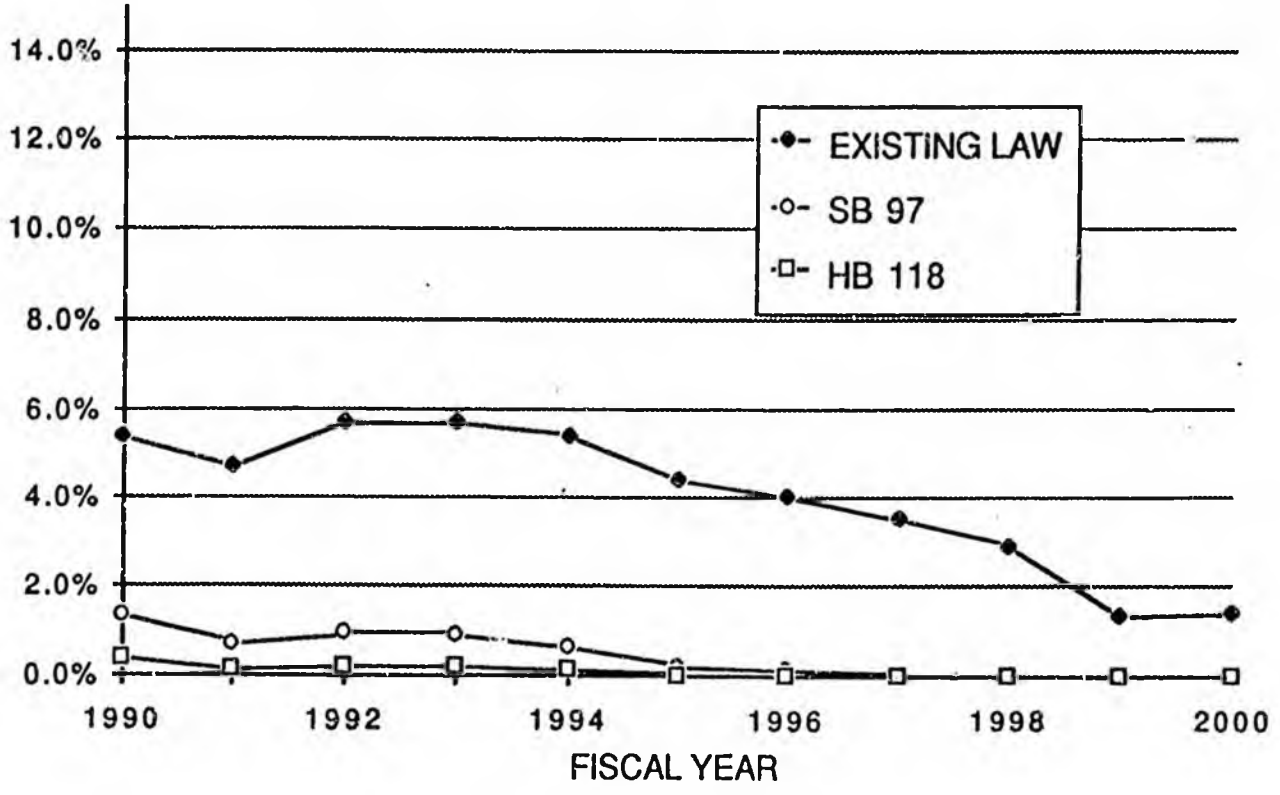


Figure 7
Estimated Production and Well Productivity
Prudhoe Bay, Kuparuk, Lisburne

	Prudhoe Bay		Kuparuk		Lisburne	
	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)	Volume (mmbbl/yr)	Avg p/well Prod (bbl/day)
1990	530	2290	102	817	16	731
1991	504	2080	97	724	15	642
1992	472	1845	89	666	15	642
1993	427	1614	81	536	15	642
1994	387	1450	69	569	14	619
1995	332	1303	59	513	12	548
1996	282	1165	50	457	11	520
1997	239	1039	42	404	10	489
1998	203	930	36	365	9	457
1999	173	834	32	341	7	376
2000	147	753	26	294	7	376

Based on the Dept of Revenue's Spring 1989 forecast. Well productivity is adjusted for well days.

COMPUTING THE SB 97 ELF

(Using typical Prudhoe Bay field values in the examples.)

The SB 97 Economic Limit Factor formula is:

ELF = (1-PEL/TP)EXP[(55,000,000*WD)/(PEL*TP/Days)]

PEL (Production at the Economic Limit) =
(300 barrels per day)*
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*300 barrels * 634 wells * 30 days = 5,706,000 barrels per month at the Economic Limit.*

TP (Total Production for the field) =
(average number of operating wells during the month)*
(number of days of production for the month)*
(average daily production per well).
For example:
*634 wells * 30 days * 2290 barrels per well = 43,555,800 barrels of production per month.*

EXP (Exponent) -- Means that the expression following is an exponent.

WD (Well Days) =
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*634 wells * 30 days = 19020 well days.*

Days = the number of days in the month for which the tax is paid.
For example: In April, 30 days.

CALCULATION EXAMPLE

=(1- PEL / TP) EXP[(55,000,000* WD)/(PEL * TP / Days)]

=[1 -(5,706,000/43,555,800)]EXP[(55,000,000*19,020)/(5,706,000*43,555,800/30)]

= (1 - .1310) EXP (.1263)

= $(.8690)^{(.1263)}$

= .9824

COMPUTING THE HB 118 ELF

(Using typical Prudhoe Bay field values in the examples.)

The HB 118 Economic Limit Factor formula is:

ELF = (1-[PEL/TP])EXP([150,000/(TP/Days)] EXP [(460*WD)/PEL])

PEL (Production at the Economic Limit) =
(300 barrels per day)*
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*300 barrels * 634 wells * 30 days = 5,706,000 barrels per month at the Economic Limit.*

TP (Total Production for the field) =
(average number of operating wells during the month)*
(number of days of production for the month)*
(average daily production per well).
For example:
*634 wells * 30 days * 2290 barrels per well = 43,555,800 barrels of production per month.*

EXP (Exponent) -- Means that the expression following is an exponent.

WD (Well Days) =
(average number of operating wells during the month)*
(number of days of production for the month).
For example:
*634 wells * 30 days = 19,020 well days.*

Days = the number of days in the month for which the tax is paid.
For example: In April, 30 days.

CALCULATION EXAMPLE

= (1-[PEL/TP])EXP([150,000/(TP/Days)] EXP [(460*WD)/PEL])

=[1 -(5,706,000/43,555,800)]EXP[(150,000/(43,555,800 /30)] EXP [(460* 19,020)/ 5,706,000])

$= (1 - .1310)\ EXP\ .1033^{1.5333}$

$= .8690^{.0308}$

= .9957

MEMORANDUM

State of Alaska
Office of the Governor
Division of Policy

TO: The Hon. Alyce Hanley DATE: April 20, 1989

FROM: Gregg Erickson

SUBJECT: Corporate Profits Earned Alaska

During the March hearings on the ELF legislation in the House you requested information on the net income earned by the fishing industry.

Based on tax data from the Department of Revenue, we estimate that 1987 taxable corporate net income in Alaska totaled $2.010 billion. Of this, $24 million (1.2 percent) was earned by corporations in fishing or fishing related fields.

Based on Dept. of Revenue data, we estimate taxable oil company income at $1.681 billion, or 84 percent of the total.

Taxable income may differ substantially from the income shown on a company's books of account. This is especially true under the special taxation arrangements adopted for the oil industry by Alaska in 1981. The recent study by Professor Deakin found that 1987 oil industry net income totaled $3.182 billion. Based on the Deakin analysis, it is likely that the oil industry accounts for more than 90 percent of total book income attributable to Alaska. The figure cannot be determined precisely, however, because comparable figures for non-petroleum book income are not available for the state.

cc: Senate Special Oil and Gas Committee

PROFITABILITY OF OIL AND GAS PRODUCTION ALASKA VERSUS FOREIGN COUNTRIES 1983–87

Thomas Horst
Horst & Associates
March 13, 1989

Introduction

The ultimate objective of this Report is to compare the royalty and tax burden of oil and gas operations in Alaska with that in foreign countries. In our search for information on how the total income from oil and gas production was shared between producers and governments, we undertook a comprehensive investigation of data published by the World Bank and other international agencies, the U.S. government, domestic and foreign trade publications, academic studies, and the companies' annual reports. In the end, we could identify only one reliable comprehensive source of data describing companies' actual oil and gas production: the supplemental information U.S. oil and gas producers are required by Financial Accounting Standard No. 69 ("FAS 69") to disclose in their annual financial reports. Although FAS 69 does not require companies to disclose total royalties, taxes or other payments to various governments per se, it does require companies to report their revenues, expenses (including income taxes), and a bottom-line result of operations by major geographic area of operations. Accordingly, we tabulated the results of foreign oil and gas producing activities for 1983-87 for the ten largest U.S. producers and compared those results to the comparable results reported by BP America and Sohio, the only U.S. company that reports separately the results of its Alaska operations.

FAS 69 Disclosure Requirements

Before describing those results, we should summarize the disclosure required by FAS 69. Broadly speaking FAS 69 requires companies to disclose information pertaining to: (1) proved oil and gas reserves, (2) capitalized costs relating to oil and gas producing activities, (3) costs incurred for property acquisition, exploration and development activities, (4) results of operations, and (5) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Domestic and foreign producing activities must be disclosed separately, and individual countries or groups of countries must be disclosed separately if appropriate for meaningful disclosure.

In disclosing their results of operations, oil and gas producers are required to report information on their (1) revenues, (2) production (lifting) costs, (3) exploration expenses, (4) depreciation, depletion, and amortization, and valuation provisions, (5) income tax expense, and (6) and the result of operations, which generally equals the excess of revenues over the

various expenses.[1] Royalty payments and net profit disbursements are excluded from gross revenues. Production or severance taxes are not excluded from gross revenues, but are instead included in production costs.

Neither corporate overhead nor interest expense is included in production costs or otherwise deducted in calculating the results of operations. Moreover, income taxes are calculated using the statutory income tax rate applied to revenues less production (lifting costs), exploration expenses, depreciation, depletion, and amortization, and valuation provisions, but not corporate overhead or interest expense. Calculation of income tax expenses reflects permanent differences between book and taxable income (e.g., the excess of percentage depletion over cost depletion) and tax credits and allowances (e.g., the investment credit), but not book-tax timing differences (e.g., book depreciation versus accelerated tax depreciation, or the expensing of intangible drilling and development costs for tax, but not for book, purposes). Because book-tax timing differences usually result in a portion of book income tax expense being deferred until a later period, and because

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[1] The reported results of operations would also be reduced by the after-tax income attributable to minority interests in consolidated subsidiaries. Because the revenue and expenses include amounts attributed to minority interests are not reported separately, the after-tax income amounts shown in the tables of this Report are before deduction of after-tax income attributable to minority interests in the consolidated subsidiaries. Moreover, we have not included amounts attributable to interests of the reporting company in non-consolidated entities (e.g., Aramco).

no account is taken of the deductions for corporate overheads and interest expense, the amount of income tax expense recorded under the FAS 69 disclosure will generally overstate the amount of income tax actually paid on account of oil and gas production. What effect this overstatement of income tax has had on the comparison of the results of foreign oil and gas operations to the results of Alaska oil and gas operations is uncertain because income tax expense has potentially been overstated in both instances.

Results of Foreign Oil and Gas Operations for 10 Largest U.S. Producers, 1983-87

The results of foreign oil and gas operations for the 10 largest U.S. producers are described in detail in Appendix I and are summarized in Table 1 on the following page. Because results for a particular producer vary widely from region to region and may vary from year to year for a particular region, we have shown on the following page the five-year (1982-87) cumulative results for all foreign operations of each of the 10 producers. Exxon is not only the largest U.S.-based foreign producers, but also the most profitable with after-tax income averaging 21.4 percent of total oil and gas revenues. At the other extreme was Shell, which consistently reported losses on its limited foreign operations. (Obviously, these results do not include the very substantial and presumably profitable non-U.S. operations of Shell's U.K. and Dutch parent corporation or its foreign sister subsidiaries.)

TABLE 1: RESULTS OF FOREIGN PRODUCTION
10 LARGEST U.S. COMPANIES, 1983-87

Company	Years	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Amoco	1983-87	18,866	7,088	3,879	3,209	17.0%
ARCO	1983-87	2,789	357	330	27	1.0%
Chevron	1983-87	14,391	8,748	6,548	2,200	15.3%
Exxon	1983-87	42,198	20,696	11,673	9,023	21.4%
Mobil	1983-87	25,153	14,301	9,836	4,465	17.8%
Occidental	1983-87	8,561	3,391	3,012	379	4.4%
Phillips	1983-87	8,140	4,450	3,848	602	7.4%
Shell	1983-87	711	(77)	54	(131)	-18.4%
Tenneco	1983-87	1,033	236	137	99	9.6%
Texaco	1983-87	16,469	9,269	7,110	2,159	13.1%
10 Companies	1987	24,472	10,653	5,998	4,655	19.0%
10 Companies	1986	20,053	7,549	4,711	2,836	14.2%
10 Companies	1985	33,867	18,041	12,986	5,055	14.9%
10 Companies	1984	32,808	18,165	12,705	5,460	16.6%
10 Companies	1983	27,111	14,051	10,027	4,024	14.8%
10 Companies	1983-87	138,311	68,459	46,427	22,032	15.9%

One of the more striking features of the results shown in Table 1 is the clear correlation between the size of a U.S. company's foreign operations and its profitability (Exxon has the largest and most profitable, Mobil the second largest and second most profitable, etc.). Whether this correlation reflects economies of scale, a tendency of older foreign operations (and longer established foreign operators) to be more profitable, or some other phenomenon has not been investigated.

Results of Alaska Oil and Gas Operations for BP America, 1986-87, and Sohio, 1983-85

The only major U.S. company that discloses separately the results of its Alaska oil and gas operations is BP America and its major predecessor corporation, Sohio.[2] The BP America/Sohio results for the 1983-87 period are summarized in Table 2. For the entire five-year period, BP America and Sohio reported after-tax income from Alaska oil and gas operations equal to 27.7 percent of Alaska revenues. This result is higher than the comparable 21.4 percent after-tax income margin reported by Exxon, the company with the most profitable foreign operations, and substantially above

[2] BP America was formed in 1987 when BP successfully acquired the remaining 45 percent of the outstanding shares in Sohio. BP America was the result of the merger of Sohio with BP North America, which held BP's Trans Alaska Pipeline System subsidiary, BP's minority interest in the Kuparuk field and associated pipeline, and other BP-owned U.S. assets.

TABLE 2: RESULTS OF ALASKA PRODUCTION
BP AMERICA 1986-87, SOHIO 1983-85

Company	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
BP America	1987	3,340	1,358	611	747	22.4%
BP America	1986	1,973	248	108	140	7.1%
Sohio	1985	4,433	2,571	1,241	1,330	30.0%
Sohio	1984	4,146	2,675	1,240	1,435	34.6%
Sohio	1983	4,013	2,336	1,037	1,299	32.4%
BP/Sohio	1983-87	17,905	9,188	4,237	4,951	27.7%

the 16.0 percent average margin for the foreign operations of the 10 largest producers taken together.

The annual results for BP America and Sohio shown in Table 2 indicates that for years through 1985 Sohio was consistently reporting after-tax income of 30 percent or more of its Alaska oil and gas revenues. The sharply lower after-tax income, 7.1 percent of Alaska oil and gas revenues, reported in 1986 was attributable primarily to the collapse of oil prices, but also to a series of unusual expenses recognized in that year. Specifically, BP America stated in the notes to its 1987 financial statements:

> During 1986 the Company recorded special charges of $1.13 billion pretax which have been classified as unusual items in the Statement of Income. The charges principally represented provisions for the restructuring of certain operations, the loss on the disposal of certain operations and the impairment of properties where future cash flows were no longer expected to recover current book values. Also included was a provision representing the excess of the Company's settlement with the Internal Revenue Service of the windfall profit tax valuation of Alaskan crude oil for the period 1980-83 over amounts previously provided.
>
> In addition to these unusual items, the exploration and production businesses recorded pretax charges of $410 million in 1986 for the impairment of leases held in oil and gas prospect inventory, over and above normal lease amortization expense. These charges were included in exploration expenses in the Statement of Income and resulted from technical reassessment and expected lower future oil prices.

The pattern of the BP America/Sohio results provide an interest contrast to that for foreign operations for U.S. companies. While both total revenues and after-tax income from foreign operations were down sharply in 1986 on account of the

lower oil prices, the ratio of after-tax income to total revenues dropped only slightly. The sharp drop in the after-tax income margin for Alaska operations compared to foreign operations may reflect two factors. First, the higher cost of transporting Alaska North Slope ("ANS") crude oil to refineries through the TAPS and then ocean transportation magnifies the impact of oil prices on ANS wellhead values. Stated differently, if the FAS 69 information consolidated the results of TAPS with ANS production, the ratio of income after taxes to total revenues would not have fallen so sharply.

Second, many foreign countries have entered into various risk-sharing agreements with oil and gas producers under which a significant portion of government revenues are calculated as a percentage of net profits -- wellhead values minus lifting and other costs -- rather than gross revenues. Risk-sharing agreements allow foreign governments to collect more revenue when oil prices are high, but reduce their revenues when oil prices are low. Consequently, the companies' ratio of income after taxes to gross revenues do not vary so sharply as oil prices fluctuate.

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
AMOCO, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Canada	1987	549	237	120	117	21.3%
Europe	1987	447	49	40	9	2.0%
Other	1987	2,021	733	406	327	16.2%
Canada	1986	521	204	89	115	22.1%
Europe	1986	430	102	69	33	7.7%
Other	1986	1,795	419	316	103	5.7%
Canada	1985	737	382	245	137	18.6%
Europe	1985	575	180	93	87	15.1%
Other	1985	3,146	1,281	732	549	17.5%
Canada	1984	727	320	216	104	14.3%
Europe	1984	579	253	59	194	33.5%
Other	1984	3,349	1,294	665	629	18.8%
Canada	1983	719	374	229	145	20.2%
Europe	1983	421	133	59	74	17.6%
Other	1983	2,850	1,127	541	586	20.6%
Foreign	1987	3,017	1,019	566	453	15.0%
Foreign	1986	2,746	725	474	251	9.1%
Foreign	1985	4,458	1,843	1,070	773	17.3%
Foreign	1984	4,655	1,867	940	927	19.9%
Foreign	1983	3,990	1,634	829	805	20.2%
Foreign	1983-87	18,866	7,088	3,879	3,209	17.0%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
ARCO, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Foreign	1987	573	90	77	13	2.3%
Foreign	1986	456	43	29	14	3.1%
Foreign	1985	674	96	95	1	0.1%
Foreign	1984	618	117	108	9	1.5%
Foreign	1983	468	11	21	(10)	-2.1%
Foreign	1983-87	2,789	357	330	27	1.0%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
CHEVRON, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Canada	1987	476	259	130	129	27.1%
Canada	1986	353	117	66	51	14.4%
Canada	1985	1,148	542	347	195	17.0%
Canada	1984	1,309	669	440	229	17.5%
Canada	1983	696	352	248	104	14.9%
Africa	1987	1,160	958	587	371	32.0%
Africa	1986	913	517	403	114	12.5%
Africa	1985	1,649	1,446	1,307	139	8.4%
Africa	1984	1,037	923	786	137	13.2%
Africa	1983	82	(57)	63	(120)	-146.3%
Other	1987	978	530	224	306	31.3%
Other	1986	895	239	176	63	7.0%
Other	1985	1,494	789	719	70	4.7%
Other	1984	1,271	865	629	236	18.6%
Other	1983	930	599	423	176	18.9%
Foreign	1987	2,614	1,747	941	806	30.8%
Foreign	1986	2,161	873	645	228	10.6%
Foreign	1985	4,291	2,777	2,373	404	9.4%
Foreign	1984	3,617	2,457	1,855	602	16.6%
Foreign	1983	1,708	894	734	160	9.4%
Foreign	1983-87	14,391	8,748	6,548	2,200	15.3%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
EXXON, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Canada	1987	965	504	209	295	30.6%
Other Western Hemisphere	1987	80	16	11	5	6.3%
Europe	1987	3,762	1,806	691	1,115	29.6%
Middle East & Africa	1987	82	(51)	12	(63)	-76.8%
Australia & Far East	1987	2,431	878	478	400	16.5%
Canada	1986	755	264	109	155	20.5%
Other Western Hemisphere	1986	62	(18)	2	(20)	-32.3%
Europe	1986	3,499	1,611	553	1,058	30.2%
Middle East & Africa	1986	62	(72)	5	(77)	-124.2%
Australia & Far East	1986	1,991	543	240	303	15.2%
Canada	1985	1,041	508	228	280	26.9%
Other Western Hemisphere	1985	98	(4)	1	(5)	-5.1%
Europe	1985	5,108	3,431	2,088	1,343	26.3%
Middle East & Africa	1985	30	(62)	3	(65)	-216.7%
Australia & Far East	1985	3,583	1,154	590	564	15.7%
Canada	1984	930	507	300	207	22.3%
Other Western Hemisphere	1984	94	(3)	(5)	2	2.1%
Europe	1984	5,159	3,793	2,506	1,287	24.9%
Middle East & Africa	1984	39	(6)	5	(11)	-28.2%
Australia & Far East	1984	3,607	1,206	589	617	17.1%
Canada	1983	937	497	316	181	19.3%
Other Western Hemisphere	1983	72	(77)	0	(77)	-106.9%
Europe	1983	4,680	3,353	2,262	1,091	23.3%
Middle East & Africa	1983	45	(6)	3	(9)	-20.0%
Australia & Far East	1983	3,086	924	477	447	14.5%
Foreign	1987	7,320	3,153	1,401	1,752	23.9%
Foreign	1986	6,369	2,328	909	1,419	22.3%
Foreign	1985	9,860	5,027	2,910	2,117	21.5%
Foreign	1984	9,829	5,497	3,395	2,102	21.4%
Foreign	1983	8,820	4,691	3,058	1,633	18.5%
Foreign	1983-87	42,198	20,696	11,673	9,023	21.4%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
MOBIL, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Foreign	1987	5,618	2,302	1,262	1,040	18.5%
Canada	1986	541	138	95	43	7.9%
Europe	1986	1,534	573	305	268	17.5%
Other	1986	1,519	1,233	732	501	33.0%
Canada	1985	974	495	356	139	14.3%
Europe	1985	2,193	1,171	839	332	15.1%
Other	1985	3,096	2,306	1,734	572	18.5%
Canada	1984	820	444	308	136	16.6%
Europe	1984	1,978	1,092	802	290	14.7%
Other	1984	2,453	1,836	1,373	463	18.9%
Canada	1983	643	368	262	106	16.5%
Europe	1983	1,670	879	633	246	14.7%
Other	1983	2,114	1,464	1,135	329	15.6%
Foreign	1987	5,618	2,302	1,262	1,040	18.5%
Foreign	1986	3,594	1,944	1,132	812	22.6%
Foreign	1985	6,263	3,972	2,929	1,043	16.7%
Foreign	1984	5,251	3,372	2,483	889	16.9%
Foreign	1983	4,427	2,711	2,030	681	15.4%
Foreign	1983-87	25,153	14,301	9,836	4,465	17.8%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
OCCIDENTAL, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Other Western Hemisphere	1987	568	108	144	(36)	-6.3%
Eastern Hemisphere	1987	629	424	347	77	12.2%
Other Western Hemisphere	1986	486	73	74	(1)	-0.2%
Eastern Hemisphere	1986	550	265	254	11	2.0%
Other Western Hemisphere	1985	422	(26)	87	(113)	-26.8%
Eastern Hemisphere	1985	1,358	663	542	121	8.9%
Other Western Hemisphere	1984	574	145	65	80	13.9%
Eastern Hemisphere	1984	1,572	734	633	101	6.4%
Other Western Hemisphere	1983	640	185	126	59	9.2%
Eastern Hemisphere	1983	1,762	820	740	80	4.5%
Foreign	1987	1,197	532	491	41	3.4%
Foreign	1986	1,036	338	328	10	1.0%
Foreign	1985	1,780	637	629	8	0.4%
Foreign	1984	2,146	879	698	181	8.4%
Foreign	1983	2,402	1,005	866	139	5.8%
Foreign	1983-87	8,561	3,391	3,012	379	4.4%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
PHILLIPS, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Norway	1987	613	192	116	76	12.4%
United Kingdom	1987	174	76	27	49	28.2%
Africa	1987	171	109	82	27	15.8%
Other Foreign	1987	72	(8)	1	(9)	-12.5%
Norway	1986	731	364	279	85	11.6%
United Kingdom	1986	152	27	11	16	10.5%
Africa	1986	142	(55)	53	(108)	-76.1%
Other Foreign	1986	53	(1)	0	(1)	-1.9%
Norway	1985	1,227	847	672	175	14.3%
United Kingdom	1985	261	127	70	57	21.8%
Africa	1985	327	183	201	(18)	-5.5%
Other Foreign	1985	88	(7)	9	(16)	-18.2%
Norway	1984	1,383	983	806	177	12.8%
United Kingdom	1984	284	129	107	22	7.7%
Africa	1984	318	177	184	(7)	-2.2%
Other Foreign	1984	89	(45)	1	(46)	-51.7%
Norway	1983	1,598	1,308	1,058	250	15.6%
United Kingdom	1983	85	20	(4)	24	28.2%
Africa	1983	292	91	172	(81)	-27.7%
Other Foreign	1983	80	(67)	3	(70)	-87.5%
Foreign	1987	1,030	369	226	143	13.9%
Foreign	1986	1,078	335	343	(8)	-0.7%
Foreign	1985	1,903	1,150	952	198	10.4%
Foreign	1984	2,074	1,244	1,098	146	7.0%
Foreign	1983	2,055	1,352	1,229	123	6.0%
Foreign	1983-87	8,140	4,450	3,848	602	7.4%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
SHELL, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Foreign	1987	193	4	2	2	1.0%
Foreign	1986	122	(5)	31	(36)	-29.5%
Foreign	1985	130	(47)	12	(59)	-45.4%
Foreign	1984	116	(20)	6	(26)	-22.4%
Foreign	1983	150	(9)	3	(12)	-8.0%
Foreign	1983-87	711	(77)	54	(131)	-18.4%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
TEXACO, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Canada	1987	534	294	143	151	28.3%
Other Western Hemisphere	1987	331	194	161	33	10.0%
Europe	1987	1,150	511	286	225	19.6%
Other Eastern Hemisphere	1987	718	433	411	22	3.1%
Canada	1986	504	238	131	107	21.2%
Other Western Hemisphere	1986	426	248	212	36	8.5%
Europe	1986	818	259	231	28	3.4%
Other Eastern Hemisphere	1986	598	309	267	42	7.0%
Canada	1985	952	555	338	217	22.8%
Other Western Hemisphere	1985	733	526	415	111	15.1%
Europe	1985	1,493	669	523	146	9.8%
Other Eastern Hemisphere	1985	1,094	769	718	51	4.7%
Canada	1984	1,088	696	401	295	27.1%
Other Western Hemisphere	1984	734	498	399	99	13.5%
Europe	1984	1,221	557	475	82	6.7%
Other Eastern Hemisphere	1984	1,232	904	812	92	7.5%
Canada	1983	978	659	374	285	29.1%
Other Western Hemisphere	1983	705	472	380	92	13.0%
Europe	1983	493	(2)	37	(39)	-7.9%
Other Eastern Hemisphere	1983	667	400	396	84	12.6%
Foreign	1987	2,733	1,432	1,001	431	15.8%
Foreign	1986	2,346	1,054	841	213	9.1%
Foreign	1985	4,272	2,519	1,994	525	12.3%
Foreign	1984	4,275	2,655	2,087	568	13.3%
Foreign	1983	2,843	1,609	1,187	422	14.8%
Foreign	1983-87	16,469	9,269	7,110	2,159	13.1%

RESULTS OF FOREIGN OIL & GAS PRODUCING ACTIVITIES
TENNECO, 1983-87

Producing Area	Year	Total Revenue	Income Before Tax	Income Tax	Income After Tax	After-Tax Income/ Revenues
Colombia	1987	130	44	30	14	10.8%
Other Foreign	1987	47	(39)	1	(40)	-85.1%
Colombia	1986	109	36	27	9	8.3%
Other Foreign	1986	36	(122)	(48)	(74)	-205.6%
Colombia	1985	153	86	22	64	41.8%
Other Foreign	1985	83	(19)	0	(19)	-22.9%
Colombia	1984	139	91	33	58	41.7%
Other Foreign	1984	88	6	2	4	4.5%
Colombia	1983	147	113	46	67	45.6%
Other Foreign	1983	101	40	24	16	15.8%
Foreign	1987	177	5	31	(26)	-14.7%
Foreign	1986	145	(86)	(21)	(65)	-44.8%
Foreign	1985	236	67	22	45	19.1%
Foreign	1984	227	97	35	62	27.3%
Foreign	1983	248	153	70	83	33.5%
Foreign	1983-87	1,033	236	137	99	9.6%

CASE 1

HOW THE ELF IS CALCULATED

ELF = (1 - [PEL/TP])exp(460*WD/PEL)

PEL = (Production at the Economic Limit) =
(300 barrels per day)*
(average number of operating wells during the month)*
(number of days of production for the month).

EXAMPLE

PEL = 300 barrels * 541 wells * 30 days = 4,869,000 barrels per month

TP = (Total Production for the field for the month) =
(average number of operating wells during the month)*
(number of days of production for the month)*
(average daily production per well).

EXAMPLE

TP = 541 wells * 30 days * 2477 barrels per well = 40,201,710 barrels per month

WD = (Well Days) =
(number of operating wells during the month)*
(number of days each well operates)

EXAMPLE

WD = 541 wells * 30 days = 16,230 well days

CALCULATION EXAMPLE

ELF = (1 - [PEL / TP])exp(460* WD / PEL)

ELF = (1 - [4,869,000/40,201,710])exp(460*16,230/4,869,000)

ELF = (1 - .1211) exp (1.533)

ELF = (.8789) exp (1.533)

ELF = .82

Offered: 3/31/89
Referred: Oil and Gas, Resources and Finance

6-0652T

Original sponsor: Finance Committee

IN THE HOUSE BY THE JUDICIARY COMMITTEE

SENATE CS FOR CS FOR HOUSE BILL NO. 118 (Judiciary)

IN THE LEGISLATURE OF THE STATE OF ALASKA

SIXTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to the oil and gas properties production tax."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 43.55.013(b) is repealed and reenacted to read:

(b) The economic limit factor for oil production of a lease or property shall be computed according to the following formula:

(1-[PEL/TP]) exp ([150,000/(TP/Days)] exp [(460 X WD)/PEL])

where: PEL = the monthly production rate at the economic limit;

TP = the total production during the month for which the tax is to be paid;

WD = the total number of well days in the month for which the tax is to be paid;

Days = the number of days in the month for which the tax is to be paid; and

exp = exponent.

* Sec. 2. AS 43.55.013(d) is repealed and reenacted to read:

(d) The monthly production rate at the economic limit for a lease or property is 300 barrels times the number of well days for the lease or property during the month for which the tax is to be paid.

* Sec. 3. AS 43.55.013(e) and 43.55.013(f) are repealed.

MEMORANDUM

State of Alaska
Office of the Governor
Division of Policy

TO: The Hon. Alyce Hanley DATE: April 20, 1989

FROM: Gregg Erickson

SUBJECT: Corporate Profits Earned Alaska

During the March hearings on the ELF legislation in the House you requested information on the net income earned by the fishing industry.

Based on tax data from the Department of Revenue, we estimate that 1987 taxable corporate net income in Alaska totaled $2.010 billion. Of this, $24 million (1.2 percent) was earned by corporations in fishing or fishing related fields.

Based on Dept. of Revenue data, we estimate taxable oil company income at $1.681 billion, or 84 percent of the total.

Taxable income may differ substantially from the income shown on a company's books of account. This is especially true under the special taxation arrangements adopted for the oil industry by Alaska in 1981. The recent study by Professor Deakin found that 1987 oil industry net income totaled $3.182 billion. Based on the Deakin analysis, it is likely that the oil industry accounts for more than 90 percent of total book income attributable to Alaska. The figure cannot be determined precisely, however, because comparable figures for non-petroleum book income are not available for the state.

cc: Senate Special Oil and Gas Committee

Offered: 3/31/89
Referred: Oil and Gas, Resources and Finance

6-0652T

Original sponsor: Finance Committee

IN THE HOUSE BY THE JUDICIARY COMMITTEE

SENATE CS FOR CS FOR HOUSE BILL NO. 118 (Judiciary)

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(1-[PEL/TP]) exp ([150,000/(TP/Days)] exp [(460 X WD)/PEL])

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TP = the total production during the month for which the tax is to be paid;

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Table 2. The Effect of Changing the Portion of Contributions to the Permanent Fund Now Set at 25% and ELF Under SB 97 (Millions $)

Fiscal Year	ELF SB 97 (Column A)	PF @ 25% Current Contribution (Column B)	PF Royalty + ELF (Column A + B)	PF @ 35%	PF @ 37.5%	PF @ 40%	PF @ 42.5%	PF @ 45%	PF @47.5%	PF @ 50%
1990	149	232	381	324	347	370	394	417	440	463
1991	156	230	386	321	344	367	390	413	436	459
1992	165	228	393	320	342	365	388	411	434	456
1993	178	229	407	321	344	367	390	413	435	458
1994	178	221	399	310	332	354	376	398	420	442
1995	167	204	371	285	306	326	346	367	387	408
1996	154	190	344	266	285	304	323	342	361	380
1997	140	179	319	251	269	287	305	323	341	359
1998	130	172	302	241	258	275	292	309	326	344
1999	118	157	275	220	236	251	267	283	298	314
2000	105	144	249	201	216	230	244	259	273	287
TOTAL	1640	2,185	3,825	3,060	3,278	3,497	3,715	3,934	4,152	4,371

Source: Alaska Department of Revenue Spring Forecast
Prepared by Senate Advisory Council April 13, 1989

These amounts represent only that portion of the royalty contribution to the Permanent Fund that is currently contributed at a rate of 25%. The royalty rate for other contributions is 50%.

Department of Revenue
April 25, 1989

Revenues Raised by ELF Formula Using Different Constants In the Formula Exponent

($mm)

CONSTANT	150,000 (current HB 118)	200,000	250,000	300,000
1990	171	155 149	139	121
1991	181	162	142	123
1992	192	169	147	127
1993	207	179	154	131
1994	207	177	151	130
1995	194	163	138	121
1996	180	151	130	114
1997	165	140	123	109
1998	157	136	118	101
1999	148	125	105	85
2000	139	115 105	92	69
	1,941	1,672	1,439	1,231

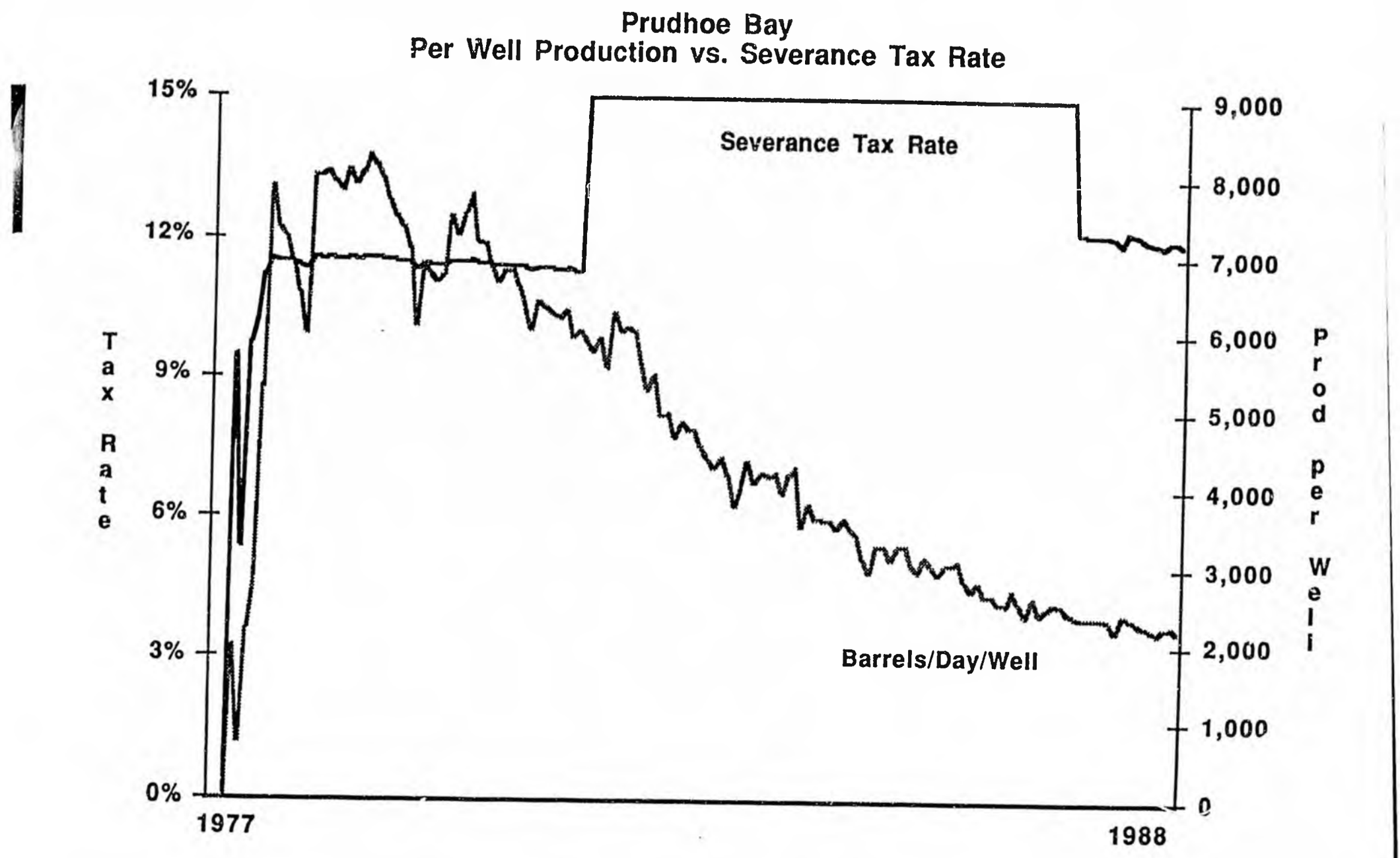
SB97

- This analysis assumes that the legislation applies to oil produced after May 31, 1989.

- Projections based on March 31, 1989 mid-case revenue scenario.

- These show the totals raised under four different constants in the exponent of the formula. SCS CSHB 118 (Judiciary) uses the 150,000 constant.

- This analysis was done at the request of legislative staff. The Department opposes changing the 150,000 constant term.


Prudhoe Bay
Per Well Production vs. Severance Tax Rate
15%
12%
9%
6%
3%
0%
Tax Rate
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Prod per Well
Severance Tax Rate
Barrels/Day/Well
1977
1988

THE ECONOMIC LIMIT FACTOR IN ALASKA'S OIL AND GAS PROPERTIES PRODUCTION TAX

By Thomas K. Williams

September 1986

About the Author

Thomas K. Williams may rightfully lay claim to being the "father of the ELF" since he was the one who first proposed the idea of an economic limit factor for the production tax in late 1976, when he was Director of Petroleum Revenue for the Alaska Department of Revenue. As director, he had immediate responsibility for administering the state's oil and gas tax laws, and he drafted many of the regulations that are still in effect for those taxes. Mr. Williams was director from September 1975 until April 1979, when he became Commissioner of Revenue for the remainder of Governor Hammond's second term. Prior to joining Revenue Mr. Williams was an Assistant Attorney General for the state, specializing in oil and gas matters. He is currently Vice President and General Counsel of Cook Inlet Region, Inc. Mr. Williams received bachelor's and master's degrees in history from Princeton and Harvard, respectively, and earned his law degree at Stanford. He has lived in Alaska since 1973.

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WHAT IS THE ELF?

The Economic Limit Factor, or ELF, is a mathematical formula that changes the rate of tax on oil and gas production under Alaska's Oil and Gas Properties Production Tax (the "Production Tax"), AS 43.55. Without the ELF, these rates would be the nominal rates set out in the statute -- 15 percent 1/ of the value of taxable oil production 2/ (12.25% during the first five years of production from a lease or property 3/) or $0.80 per barrel, 4/ whichever is greater. 5/ The $0.80 cents-per-barrel amount is for oil having an API gravity of 27 degrees, and it is increased or decreased by half a cent for each degree above or below 27 degrees, respectively, in the API gravity of the actual oil produced. 6/ This adjustment to the cents-per-barrel amount

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1/ AS 43.55.011(b) (15 percent rate for oil produced after June 30, 1981).

2/ AS 43.55.011(a) excludes "any oil the ownership or right to which is exempt from taxation". Such exempt oil almost invariably is state or federal royalty oil.

3/ AS 43.55.011(b) ("for a lease or property coming into commercial production after June 30, 1981, the percentage-of-value amount equals 12.25 percent of the gross value . . . of taxable oil produced from the lease or property in the first five years after the start of commercial production and equals 15 percent . . . thereafter").

4/ AS 43.55.011(c). This statute also specifies a cents-per-barrel rate of $0.60 for "taxable old crude oil", referring to "old oil" under former federal oil price controls. With the expiration of those controls, there is no longer any current production to which the $0.60 rate applies.

5/ AS 43.55.011(a) requires payment of the Production Tax on the basis of the greater amount, with the percentage-of-value amount deemed to be the greater if both amounts happen to be equal. It used to be necessary to establish which amount was being used when both amounts were equal because former AS 43.55.011(d) (repealed by § 18, ch. 116, SLA 1981) called for certain payments into the Alaska Native Fund when the Production Tax was paid on the cents-per-barrel basis.

6/ AS 43.55.012(b).

for API gravity is made before the ELF is applied. 7/ For taxable gas, the nominal tax rate is greater of ten percent of its value or $0.064 per thousand cubic feet (Mcf) 8/ before applying the ELF.

The ELF ranges in value from zero to one, although the way the formula is set up, it could approach, but never actually reach, one. However, by statute, if the calculated value of the ELF under the formula is greater than 0.7 for oil during the first ten years of production from a lease or property, then the ELF is defined to have a value of one; 9/ after ten years of production, the ELF equals its calculated amount under the formula, whether it is above or below 0.7. 10/ There is no corresponding rule changing the value of the ELF for gas from its calculated value under the gas ELF formula. 11/

The actual tax rate for taxable production from a lease or property equals the nominal tax rate multiplied by the ELF for that lease or property. Thus for instance, with oil, as the ELF varies from one down to zero, the effective

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7/ Under AS 43.55.011(a) "[t]he tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-barrel amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor". AS 43.44.011(c) states "[t]he cents-per-barrel amount equals . . . $0.80 per barrel . . . as adjusted by AS 43.55.012 [providing for the API gravity adjustment]". Thus, the API gravity adjustment applies in determining the cents-per-barrel amount under "(c) of this section", and then, if that amount is greater than the percentage-of-value amount, it is multiplied by the ELF.

8/ AS 43.55.016. The reference in AS 43.55.016(c) to an "adjust[ment] by AS 43.55.012" in the $0.064 cents-per-Mcf rate refers to provisions in AS 43.55.012 that have since been repealed. AS 43.55.012(b), the only portion of AS 43.55.012 currently remaining in effect, is applicable only to oil. The reference to AS 43.55.012 is therefore an artifact from prior versions of the statute and no longer has any application; the cents-per-Mcf rate is uniformly $0.064 per Mcf (before applying the ELF).

9/ AS 43.55.013(b)(3).

10/ AS 43.55.013(b)(4).

11/ AS 43.55.013(c).

rate of tax can range between something at or very near its nominal rate of 15 percent (or $0.80 per barrel, if greater), down to zero. 12/

12/ The cents-per-barrel and cents-per-Mcf rates represent, in effect, floors on the prices used for Production Tax purposes. If prices drop below these floor levels, the cents-per-barrel or cents-per-Mcf rate kicks in. However, neither of these represents any sort of floor on the actual amount of tax collected. As explained below, the purpose of the ELF is to scale down the burden of the Production Tax so that the tax does not cause the cessation of production before the property would otherwise reach its economic limit (break even point). If the amount of production needed to break even equals the amount currently being produced, the ELF makes the tax zero whether the tax is calculated on a percentage-of-value basis or on the cents-per-barrel (or cents-per-Mcf) basis.

HOW THE ELF WORKS: THE BASIC THEME

The ELF depends primarily on two things. One is the volume of production needed to "break even" so that the gross value of the production just equals the total direct operating costs (as defined in the statute) for producing that oil or gas. The other is the volume of production actually produced during the month in question.

These two factors have a determinative role in the changing economics of an oil and gas property during its productive life, and the ELF attempts to recognize the economics and set the effective tax rate at appropriate levels throughout that productive life. In general the cost of producing an additional barrel or oil or an Mcf of gas starts off relatively low and increases with time, until eventually the cost of getting the next barrel or Mcf gets so high that it is no longer profitable to continue producing. This point at which operations cease to be profitable is called the economic limit.

The ELF, which gets its name (Economic Limit Factor) from this concept of an economic limit, takes an approximation of how much production is needed to break even at the economic limit, 13/ and then compares that production rate

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13/ The statute makes an approximation of the operating costs at the economic limit by specifically listing certain types of operating costs that one would reasonably expect to continue being incurred right up until the economic limit is reached. Such costs are "royalty, production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations." AS 43.55.013(e) (oil); AS 43.55.013(h) (gas). Other current costs are specifically excluded from the calculation of the operating costs at the economic limit because one would reasonably expect them to have been discontinued or no longer incurred by the time the economic limit is reached. These excluded costs are capital expenditures, tangible or intangible drilling expenses, costs of well workovers, and costs of replacement or repairs other than routine maintenance. All of these are excluded because they represent expenses or capital investments that a reasonable person would have discontinued making once the property got close enough to its economic limit that the additional cost or investment no longer promised to pay for itself. Amortization and depreciation are excluded because all past capital investments ordinarily should be fully amortized or depreciated before

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at the economic limit (PEL) to the volume actually being produced. This ratio is an indicator of the profitability of the lease or property. The smaller PEL is in proportion to the total production (TP) currently being produced, the more profitable the lease or property is and, theoretically, the better it can bear a greater "slice off the top" for the Production Tax. Hence the ELF approaches one (and the effective tax rate approaches its maximum possible rate) when the property is most profitable, but later as the property becomes more and more expensive to operate and less and less profitable, the ELF decreases and scales down the tax rate, until finally both the ELF and the tax are zero when the economic limit is reached.

An example will illustrate exactly how this occurs. In its simplest form, the ELF is one minus the ratio of PEL to TP. Put into algebraic terms, the formula for the ELF is:

$$ELF = 1 - [PEL/TP],$$

where PEL is the production rate needed to cover the projected direct operating costs at the economic limit, and TP is total current production. This is the present formula

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the property reaches its economic limit. Taxes are excluded because (a) the ELF would have reduced the Production Tax to zero when the property reaches the economic limit and (b) ad valorem taxes, even on a replacement-cost basis of assessment, should reflect the fact that there is no remaining economic life for the assets and hence they would be fully depreciated for assessment purposes at the economic limit (the third tax, the conservation tax of one eighth of a cent per barrel, AS 43.57, is disregarded as having a minimal effect). Insurance and overhead are excluded because they were not considered to be sufficiently "direct" in nature. The costs of terminating production operations and shutting down the property are excluded because they are not costs of production, but costs of ceasing production; if anything, the financial advantage (due to the time value of money) to be gained by deferring the termination costs might be enough in itself to induce an operator to continue producing a property even after it reaches what would ordinarily be its economic limit (i.e., after its production revenue started falling short of the direct operating expenses for continuing that production). The statute also allows the Department of Revenue to adopt regulations that include additional direct operating costs that are not specifically set out in the statute; the Department has adopted no regulation including any such additional types of cost.

for the gas ELF 14/ (formerly, when there were still federal oil price controls, it was also the formula for "old oil" production 15/).

Suppose there is a gas-producing property for which the PEL is determined to be 150,000 Mcf per month. Suppose further that initial production from this property is 500,000 Mcf per month. The ELF will be:

$$ELF = 1 - [PEL/TP]$$

$$= 1 - [150,000/500,000]$$

$$= 1 - [0.300000]$$

$$= 0.700000$$

The effective rate of tax will be seven percent of the value of the gas (0.700000 times the nominal rate of 10% equals 7%) or $0.0448 per Mcf (0.700000 times the nominal rate of $0.064 equals $0.0448), whichever is more.

Now suppose the property continues producing at 500,000 Mcf per month for five years, and then, starting in year six and each year thereafter, the rate of monthly production drops by 70,000 Mcf. The following table shows what the ELF and the effective tax rates will be during the life of this property:

Year	Production Rate	ELF	Effective Tax Rate % of Value	Effective Tax Rate $ per Mcf
1 - 5	500,000	0.700000	7.00000%	$0.044800
6	430,000	0.651163	6.51163	0.041674
7	360,000	0.583333	5.83333	0.037333
8	290,000	0.482759	4.82759	0.030897
9	220,000	0.318182	3.18182	0.020364
10	150,000	0.000000	-0-	-0-

14/ Id. ("The economic limit factor for gas 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").

15/ Former AS 43.55.013(a), repealed by § 18, ch. 116, SLA 1981 ("The economic limit factor for old crude oil production of a lease or property equals one minus the ratio of the monthly production at the economic limit to the production during the month for which the tax is to be paid").

As one can see from this table, when current production starts to decline, the ELF starts falling off too, but at a somewhat slower rate. For example, between Years 5 and 6 production in this illustration falls from 500,000 to 430,000 Mcf, a drop of 14 percent (the drop of 70,000 is 14% of 500,000), but the ELF drops from 0.700000 to 0.651163, a decline of only 6.9767 percent (the change of 0.048837 in the ELF between Year 5 and Year 6 is 6.9767% of 0.700000). However, as the table clearly shows, the ELF eventually does fall off fast enough to get to zero when the economic limit is reached.

What this means in practical terms is that the ELF operates to keep the effective tax rate from initially falling off quite as rapidly as does the profitability of the property measured by the ratio of current production to production at the economic limit. Thus the State's Production Tax collections are higher than they would be if the ELF scaled the tax rate down in direct proportion to the property's profitability.

There is one other thing that this illustration reveals about the ELF, and that is why the effective tax rate cannot ever equal the nominal rates set out in the statute (except of course where there is a special statutory rule making the ELF one if its computed value under the formula is greater than 0.7). The reason is that the ELF itself can approach, but never quite reach, the value of one. For the ELF to equal one, the ratio of production at the economic limit to current production must be zero. 16/ In mathematical terms,

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16/ In the "complex" explanation of the ELF, the effects of the exponent in the oil ELF are explained. With the exponent, there is theoretically a second way for the ELF to equal one, and that is if the exponent is zero and the number to which the exponent is to be applied is not equal to zero. However, since the exponent is, in effect, the ratio of 460 barrels a day per well to the actual average daily production rate per well during the month in question, the exponent cannot be zero unless actual production were infinite (this is because 460 divided by any finite number, no matter how huge, will yield a number greater than zero; otherwise, if zero were the quotient, one would be able to reverse the process and multiply that huge but finite number by that quotient (zero) and get back to 460, but zero times any finite number is always zero). Since an infinite production rate is one of the two possible conditions that are described in the "simple" version of the ELF as making the ELF exactly equal to one, there is no practical difference between the "simple" and "complex" versions as to why the ELF is always less than one in the physical world.

if 1 = ELF, then 1 = 1 - [PEL/TP].

Clearly, [PEL/TP] must equal zero for this equation to be true, since if any number other than zero is subtracted from one, the result will not equal one. Thus,

PEL/TP = 0, or

multiplying both sides of this last equation by TP,

PEL = 0 x TP.

There is no finite number for TP which will, when multiplied by zero, yield a value for PEL other than zero. This is because zero times any finite number is always zero. And so, if the ELF is to equal one, either current production (TP) is infinite (which is possible in mathematics, but not in the physical world) or PEL equals zero (again, a practical impossibility, since no field would have costs of production equal to zero, especially at its economic limit).

Thus, the larger current production becomes in proportion to PEL, the closer the ELF comes to a value of one, but it never reaches one under the formula in the real world.

REASONS FOR THE ELF

The ELF operates to reduce the effective rate of the Production Tax as an oil and gas property nears its economic limit; i.e., the point where the income (gross value) from producing a barrel or Mcf of production from that property is just enough to cover the costs of producing that barrel or Mcf. At the end, when the property actually reaches its economic limit, the ELF makes the tax rate zero. Why has this ELF feature been included in the Production Tax?

The reasons for the ELF are both historical and economic. Prior to the enactment of the ELF in 1977, Alaska had a "stair stepped" Production Tax on oil in which the tax depended on the average daily rate of production per well. The first 300 barrels a day per well were taxed at five percent of their gross value, the next 700 barrels a day were taxed at six percent, and average daily production in excess of 1,000 barrels a day per well was taxed at eight percent. 17/ In addition, there were three similarly "stair

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17/ Former AS 43.55.010, repealed by § 9, ch. 136, SLA 1977. The three-tiered "stair step" tax (enacted in ch. 4, FSSLA 1973) replaced an earlier four-tier version, in which the four "stair steps" for percentage-of-value had been enacted first (ch. 247, SLA 1970), with the cents-per-barrel rates added later (ch. 101, SLA 1972). The four "steps" in the original progressive tax rate structure were 0 - 300 barrels a day per well (3% rate), 301 - 1,000 barrels a day per well (5% rate), 1,001 - 2,500 barrels a day per well (6% rate), and 2,500+ barrels a day per well (8% rate). When the cents-per-barrel rates were added to the Production Tax in 1972, they were coupled with a credit for royalty payments to the State, the intent and effect of which was to set a floor on combined state revenues from royalty and Production Tax, corresponding to a "wellhead" price of $2.65 a barrel (which would have dropped to $2.50 on July 1, 1980 if the law had remained in effect). If prices dropped under that floor, the "lost" royalty income would be made up by the corresponding reduction in the royalty credit against the cents-per-barrel rates. See ch. 101, SLA 1972; 1972 House J. 915-916 (Governor Egan's transmittal letter for House Bill 817, introducing the royalty credit concept; the House Finance Committee took the substance of HB 817 and incorporated it into a House Committee Substitute for a Senate Bill, SB 168, that had already passed the Senate; the version that became chapter 101 of the 1972 Session Laws was the Second Free Conference Committee

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stepped" cents-per-barrel rates -- $0.16875 on the first 300 barrels a day, $0.2025 on the next 700, and $0.27 on anything over 1,000 barrels a day. 18/ These cents-per-barrel rates were for oil having an API gravity of 27 degrees, and they were increased or decreased by two percent for each degree of API gravity that the actual oil production was over or below 27 degrees. The actual tax to be paid was the higher of the two, percentage-of-value or cents-per-barrel. 19/ The cents-per-barrel amount would be greater when the "wellhead" price 20/ fell below $3.375; for higher

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Substitute for SB 168, SFCCS HCS SB 168). Litigation over this and other enactments of the 1972 Legislature quickly ensued -- Amerada-Hess Corp., et al., v. State (Superior Ct. No. 72-2719 Civil), ARCO Pipe Line Co. v. Herbert (Superior Ct. No. 72-2798 Civil), Mobil Pipe Line Co. v. State (Superior Ct. No. 72-2720 Civil), consolidated. Legislation enacted by the 1973 Special Session, including repeal of the royalty credit provisions, made part of the litigation moot and allowed the remainder to be settled.

18/ Former AS 43.55.015(a), repealed by § 9, ch. 136, SLA 1977. Actually, the base cents-per-barrel rates (before any adjustment for API gravity) were not constant, but changed from month to month based on monthly changes in the Wholesale Price Index for crude petroleum from the Index for the month of December 1973. See former AS 43.55.015(c); Union Oil Co. of Cal. v. Dept. of Revenue, 560 P.2d 21 (Alaska 1977) (upholding the Department's regulation, former 15 AAC 05.694, which made the December 1973 Index the base Index). This monthly adjustment to the cents-per-barrel rates, in turn, meant that the effective floor price for the Production Tax revenue (i.e., the price at which the cents-per-barrel tax became greater than the percentage-of-value tax) also varied from month to month, depending on the Index.

19 Former AS 43.55.010(e).

20/ The issue of what is the "wellhead" for royalty and Production Tax purposes has itself been hotly disputed. In Alaska when oil emerges from the ground at the "Christmas tree" atop the well casing, it is cleaned and dehydrated and separated from associated and dissolved gases before it is in a marketable condition. After it has gone through the surface equipment to make it marketable, it is then metered and either sold or

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prices, the percentage-of-value amount would be the greater. 21/ Thus, the cents-per-barrel rates, in effect, established a floor price for the value of the oil for Production Tax purposes, regardless of how low the actual "wellhead" price might fall.

To illustrate how the "stair step" tax worked, suppose a property had 10 wells and produced 450,000 barrels of 27-degree API gravity, valued at $10 apiece during a 30-day month. The tax would be calculated as follows:

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transported away from the property through some common carrier pipeline. In a number of other states, the "wellhead" price is effective at the outlet of the tank gauge or custody transfer meter at which it is first measured in a marketable condition. In Cook Inlet and on the North Slope, it may be miles between the Christmas tree and the custody transfer meter, and the separators and dehydrators represent significant expenditures. If the incidence of the tax or the royalty is at the custody transfer meters, none of the costs incurred upstream from that point for the gathering lines, separators and dehydrators and associated equipment would be deducted in determining the price or value for purposes of paying the tax or royalty. Conversely, if the incidence of the tax or royalty is at the Christmas tree, then all those costs are deducted in determining the price or value on which the tax or royalty is computed and paid. The phrase "wellhead price," while commonly used, can therefore be misleading or at least ambiguous in the Alaskan context, since it is unclear whether it refers to the price at the custody transfer meter or a price further upstream, perhaps as far as the Christmas tree. The Production Tax is based on the "gross value at the point of production", which is specifically defined to be the point of measurement (as opposed to the Christmas tree); see AS 43.55.140(6), 15 AAC 55.210(6).

21/ Five percent of $3.375 equals $0.16875, which is exactly what the cents-per-barrel rate was for the first "stair step." Six percent of $3.375 is $0.2025, the same as the rate for the second "step," while eight percent of it is $0.27, the rate for the third. By 1977 the escalation in the cents-per-barrel rates due to the Wholesale price Index (see note 16, above) had raised the effective floor from its original $3.375 to approximately $6.10.

0 - 300 bbl/day "stair step": 10 wells, times 300 barrels per well a day, times 30 days, equals 90,000 barrels in this "stair step" of the 450,000 total taxable barrels produced. Five percent of 90,000 barrels at $10 each equals $45,000. 90,000 barrels times the cents-per-barrel rate of $0.16875 22/ equals $15,187.50.

301 - 1,000 bbl/day "stair step": 10 wells, times 700 barrels per well a day, times 30 days, equals 210,000 barrels in this "stair step", of the remaining 360,000 barrels that didn't fall into the first "step". Six percent of 210,000 at $10 each equals $126,000, while 210,000 times the $0.2025 cents-per-barrel rate equals $42,525.

1,000+ bbl/day "stair step": 450,000 total barrels, minus the 90,000 barrels falling in the first "stair step" and the 210,000 barrels falling in the second, leaves 150,000 barrels to fall in this top "step." Eight percent of 150,000 at $10 a barrel is $120,000, and at $0.27 a barrel the cents-per-barrel amount is $40,500.

The total percentage-of-value amount would be $45,000 plus $126,000 plus $120,000, or $291,000. This is greater than the cents-per-barrel amount of $98,212.50 ($15,187.50 + $42,525 + $40,500), so the actual tax would be paid on the percentage-of-value basis. The effective rate of tax in this example would be 6.47 percent ($291,000 total tax, divided by a total value of $4,500,000 for the 450,000 barrels, equals 0.0647).

After this tax system was enacted in October 1973 (ch. 4, FSSLA 1973), factors affecting the Alaska oil and gas market changed dramatically. The Arab oil embargo of the United States in early 1974 caused oil prices, which had doubled since the previous May, to redouble. Construction of TAPS finally began in 1974, but costs for constructing

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22/ For simplicity, the example uses the original rates set out in the statute. In actual practice, those rates would first have been adjusted for changes in the crude oil Wholesale Price Index (WPI). One might also note that, by having 27 degree API gravity oil in the example, the example does not show how to make the API gravity adjustment of two percent in the WPI-escalated cents-per-barrel rates per degree above or below 27 degrees would be made. For an example illustrating all these aspects of the former tax, see Alaska Department of Revenue, Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement (February 1977) (the "1977 Tax Study"), pp. II-6 to II-10.

that project continued to skyrocket over all earlier projections. The federal government imposed a complex system of price controls on crude oil and refined products, with a big question mark deliberately left in the system as to how Prudhoe Bay oil would fit into it all once that field came into production.

Uncertain as to what all these changes might mean in terms of the profitability of Prudhoe Bay and the appropriate level and type of state taxation, the Alaska Legislature in 1975 retained Tanzer Economic Associates, Inc. to conduct an economic analysis of Prudhoe Bay, its profits, and the effects of state taxation policy on those profits. In January 1976 Tanzer's results were released. 23/ The "Tanzer Report" concluded that Alaska could significantly increase the overall level of its tax burden on Prudhoe Bay and still provide a sufficient degree of profitability to reward the oil companies there for investing in the development of the field.

A flurry of legislative proposals to increase oil taxes immediately followed, ranging from "excess profit" taxes to a "separate accounting" income tax, with higher Production Tax rates as an option somewhere in between. In the face of misgivings by the Department of Revenue about some of the proposals and the lack of a clear legislative consensus about which proposal(s) to adopt, Governor Hammond prevailed upon the Legislature to give the Department a year to make a comprehensive study of Alaska's then current tax structure and make recommendations in early 1977 about any changes that should be made. 24/ Because of strong support in the Senate for a "separate accounting" income tax 25/ and be-

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23/ Tanzer Economic Associates, Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential (January 9, 1976).

24/ The 1976 Legislature, through a Committee Substitute for Senate Concurrent Resolution 101 (CS SCR 101), resolved that the Legislative Council, through its Interim Committee on Oil and Gas Leasing and Taxation Policy, was to cooperate with the Administration in making a comprehensive and definitive study of Alaska's oil and gas leasing and taxation policies, with recommendations for improvement.

25/ "Separate accounting" is one of two basic ways of determining how much of a multistate business's taxable income is attributable to its activities in a particular state for purposes of that state's income tax. It attempts to isolate the in-state activities from the rest of the business and see how much income results

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cause of criticism of the state income tax as early as 1973, 26/ the Department of Revenue and the Legislative Council engaged Professors Jerome M. Ziefman and Kenneth G. Ainsworth to make a special study of the income tax. 27/

The Department's report -- Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement (February 1977) (the "1977 Tax Study") 28/ -- was transmitted to the Governor on February 11, 1977. Besides incorporating the criticisms and recommendations of Professors Ziefman and Ainsworth about the income tax, the 1977 Tax Study examined the Production Tax, the state ad valorem tax on pipelines and production and exploration equipment and facilities, and the reserves tax. In its review of the Production Tax, the 1977 Tax Study noted:

> . . . Typically production taxes do not reflect the expenses incurred to obtain the production. The tax is either some specified percentage of the gross value of the production or a flat fee of so

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from the in-state activities. The other way is "apportionment," in which a slice of the business's total income is attributed to its in-state activities on the basis of a prescribed formula. Of the consultants advising the Legislature in the mid-1970s, perhaps the most respected was Milton Lipton of Walter J. Levy & Associates. He and Dr. Michael Tanzer of Tanzer Economic Associates, Inc. were preeminent advocates of separate accounting as the way to reform the state income tax and even Alaska's oil and gas tax structure in general.

26/ Milton Lipton, "Testimony at the Joint Hearings of Proposed Oil and Gas Legislation before the House and Senate resources Committees" (March 23, 1973 transcript), p. 7.

27/ Ziefman and Ainsworth, The Taxation of the Petroleum Industry under Alaska's Corporate Income Tax (January 9, 1977).

28/ The principal draftsmen of the 1977 Tax Study were John R. Messenger, then Deputy Commissioner of Revenue (Taxation), and Thomas K. Williams, then Director of the Department's Petroleum Revenue Division. Important editorial review and suggestions were made by Dr. David L. T. Knudson, Petroleum Economist in the Petroleum Revenue Division. Revenue Commissioner Sterling Gallagher closely supervised the preparation of the report.

many cents per unit of production. Since it is not based on net proceeds of the production operation, the production tax simply represents another cost of doing business to the producer. 29/

. . . .

Once a discovery has been made and production begins, however, the production tax (and the landowner's royalty) can have a more significant impact on the economics of the production operation and the associated decisions. As operating costs rise during the life of the field, the profit margin shrinks. At some point the total production costs overtake the value of the oil or gas produced, and production can then be continued only by operating at a loss. As one of the costs of doing business, the production tax contributes to the total costs and tends to hasten the time when this break-even point (called the economic limit) is reached. 30/

Besides this negative economic effect of production and severance taxes in general, the 1977 Tax Study drew attention to a particular problem with the "stair step" tax as it applied to areas of Alaska where the operating costs differed greatly from each other:

The current State oil production tax contains a "stair step" feature which is intended to alleviate the adverse impact that a production tax can have on an oil well operating close to its true economic limit. . . . The "stair step" feature of the existing oil production tax schedule is an attempt to reduce the tax rate as production falls closer to the true economic limit. The tax rate declines from 8% to 6% to 5% as individual well output falls. Unfortunately, the current "stair steps" appear to be sized incorrectly.

Economic factors governing production operations vary widely in the State of Alaska. Some areas in the State are located close to the refinery market and have low operating costs. In these areas wellhead values are high. As a consequence, the true economic limit (measured in barrels per day) for these properties can be quite low: 50 to 75 barrels a day per well, or even lower, in some cases in Cook Inlet.

29/ 1977 Tax Study, p. V-19.

30/ Id., p. V-21.

> Other crude oil wells in Alaska are not located close to refinery markets and could have extremely high operating costs. The netback value in the field for these isolated areas is lower than in Cook Inlet and the operating and capital costs can be much higher than in Cook Inlet. Accordingly, the true economic limit (measured in barrels per day) for these producing properties can be quite high. Depending on the property, this limit might range from 300 to perhaps 1000 barrels per day [per well]. There is, then, a rather wide range of values which can be generated regarding the minimum production level at which Alaska crude oil wells can be operated.
>
> From this perspective, an economic flaw in the existing or any other "stair step" production tax schedule becomes obvious. By establishing a fixed schedule of "stair stepped" tax rates, the State crude oil production tax is based on the faulty assumption that production economics are similar in Cook Inlet, Prudhoe Bay, and everywhere else in Alaska. 31/

To take care of these problems, the 1977 Tax Study made the following recommendation to replace the "stair steps" with the ELF: 32/

> The Department of Revenue recommends perfecting the "stair step" approach as a means of eliminating effects of the production tax on the economics of oil production operations. The key to doing so is not found by creating a series of "steps" and rates that succeed in this for any one area of the State, such as Cook Inlet. As explained in Chapter V, a well producing 1000 bar-

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31/ Id., pp. V-28 to V-30.

32/ The original idea for an economic limit was by the then Director of the Petroleum Revenue Division of the Alaska Department of Revenue, Thomas K. Williams, in response to criticism, particularly by Milton Lipton, about the adverse economic effects of the Production Tax on properties as they near their economic limit. The precise formula for the ELF proposed in the 1977 Tax Study (and still the formula for the gas ELF) was developed jointly by Mr. Williams and Dr. David L. T. Knudson, Petroleum Economist in that division. The exponent for the oil ELF and the number 460 appearing in the exponent were features added during the legislative process as the result of work by Alan Latham, who was working for the Legislature.

> rels a day may be quite a money maker in Cook Inlet but be mediocre or even marginal in other areas of the state such as the Interior or North Slope. Consequently the "stair steps" that succeed for the Inlet won't eliminate the economic effects of the tax elsewhere. Conversely, "stair steps" designed to eliminate those effects [for] production on the North Slope would give too much away to production in the Inlet.
>
> To eliminate this difficulty, the Department of Revenue recommends an Economic Limit Factor (ELF), based on the ratio of the rate at the true economic limit to the current production rate, as a mechanism for scaling down the tax rate as the production declines toward the economic limit. This would be done by multiplying a basic tax rate times the difference between unity (the number, one) and the ratio of rate at limit to current rate.
>
> . . . .
>
> If the tax law conclusively sets the rate at the economic limit at some specific rate like 200 barrels a day per well, the ELF becomes simply one more economically rigid structure like the present "stair steps." It would not respond to the great regional differences in economic scale for production operations in Alaska. But the great advantage of the ELF over any specific set of "stair steps" is that it can be tied to the actual economic condition of a property anywhere in the state . . . . (emphasis in original) 33/

This was the first public proposal to adopt the ELF as a replacement for the "stair steps" in the Production Tax. Instead of a series of discrete "steps" in production rates at which tax rates changed, the ELF represented in effect a smooth curve, a series of an infinite number of "steps" each infinitesimally small. But beyond simply smoothing the "steps" into a continuous curve, the ELF had the additional advantage of allowing the whole curve itself to be shifted, to reflect the rate of production needed for that particular property to cover its basic operating costs at the economic limit. It could reflect the fact that in remote areas of Alaska like Prudhoe Bay, the rate of production needed merely to break even would be very much greater than the rates needed to break even in the more accessible areas like Cook Inlet and the Kenai Peninsula. Thus, the adverse economic

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33/ 1977 Tax Study, pp. VI-17 and VI-19.

effects on the economic life of an oil and gas property were no longer a necessary evil of a tax based on gross production value as the Production Tax is.

Governor Hammond acted on this recommendation by introducing Senate Bill 238 to the 1977 Session of the Legislature. 34/ After much legislative wrangling, an amended version of this bill (FCCS HCS CSSB 238) finally passed, and the ELF became part of the Production Tax. 35/

34/ See 1977 Senate Journal, pp. 540-541 (Governor's transmittal letter).

35/ Ch. 136, SLA 1977.

HOW THE ELF WORKS: VARIATIONS ON THE THEME

A. Introduction to the Exponent. The ELF formula for gas production (and formerly for "old oil" under now expired federal oil price controls) is simple and straightforward in its operation. It is merely one minus the ratio of production at the economic limit (PEL) to current production (TP), or to put it into mathematical symbols:

$$ELF = 1 - [PEL/TP]$$

As current production (TP) declines toward the "break even" rate (PEL), the ratio of PEL to TP gets larger and larger, eventually equaling one when TP has declined to the point that it equals PEL. At that point, the ELF becomes 1 - 1, or zero. The tax is then also zero.

This same formula is at the root of the ELF for oil, except that there is, in addition, an exponent that is applied to it. (For a review of how exponents work and what fractional exponents mean, see Appendix A.)

The exponent in the oil ELF is a fraction whose numerator is 460 times the number of "well days" in the month when the oil was produced, and whose denominator is the monthly production rate at the economic limit. The number of well days is simply the sum for all wells of the number of days each of them was operated during the month. If 10 wells were each operated for 30 days during a month and two others were operated for 25 days each, then the number of well days is 350 (10 times 30, plus two times 25).

Depending on what PEL is, the exponent may be greater than, equal to, or less than one. If it is greater than one, the exponent is a "net power function" -- that is, the effect of raising to a power equal to the numerator of the exponent outweighs the effect of taking the a root equal to the denominator of the fraction. Conversely, if it is less than one, the exponent is a "net root function" and the effect of taking the root outweighs that of raising to the power.

As set out in the "simple" explanation of the ELF, the value of one minus the ratio of PEL to TP is always less than one and can range all the way down to zero. For numbers between zero and one, the effect of a "net power function" is to make the result smaller than the starting number. For example, 0.9 squared is 0.81; 0.01 to the fifth power is 0.0000000001; 0.5 to the "1.000001"-th power is 0.499999653. Conversely, the effect of a "net root function" on this range of numbers is to produce a larger number: the square root of 0.81 (0.81 raised to the "one half"-th power) is 0.9; the fifth root (the "1/5"-th or

"0.2"-th power) of 0.0000000001 is 0.01; and 0.5 to the "0.999999"-th power is 0.500000347.

The value of PEL therefore has an important but subtle effect on the exponent. If PEL corresponds to more than 460 barrels a day per well, the exponent becomes a "net root function" and makes the value of the ELF larger than the starting number to which the exponent is applied. On the other hand, if PEL is less than 460 barrels times the number of well days, the exponent is a "net power function" and makes the final value of the ELF less than the number to which the exponent is applied.

B. The PEL Presumption: To Rebut or Not to Rebut?

PEL appears twice in the oil ELF formula -- once in the exponent and once in the calculation of the number to which the exponent is applied:

$$ELF = (1 - [PEL/TP])^{([460 \times WD]/PEL)}$$

For oil there is a rebuttable presumption that PEL equals 300 barrels times the number of well days in the particular month. 36/ The presumption may be rebutted only once a year, and if it is rebutted, the value that is demonstrated to be the proper PEL must be used for that entire calendar year. 37/ If the presumption is not rebutted, then the formula for the ELF is, in effect, the following:

$$ELF = \{1 - ([300 \times WD]/TP)\}^{(460/300)}$$

The decision to rebut the presumption or not, presents some subtle trade-offs that must be carefully considered before proceeding. On the one hand, if the presumption is not rebutted, then the exponent is a "net power function," which produces a result that is smaller than the number to which the exponent is applied. On the other hand, if the presumption is rebutted and shown to be greater than 300 barrels per well day, then the ratio of PEL to current production will be made greater, leaving a smaller number to which the exponent is applied. If the demonstrated PEL is still less than 460 barrels per well day, the exponent will remain a "net power function" although, as the value for PEL approaches 460 barrels per well day, the effectiveness of the exponent in reducing the number to which it is applied will diminish. The effects of rebutting the PEL -- that is, the reduction in the difference between one and the ratio of PEL to current production (that difference being the number

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36/ AS 43.55.013(d).

37/ Id.

to which the exponent will be applied), and the "net power function" nature of the exponent -- will both be working in the same direction and reduce the ELF.

If PEL equals 460 barrels per well day, the exponent becomes exactly equal to one and has no effect at all on the number to which it is applied. The effect of rebutting the presumption is then simply the reduction in the difference between one and the ratio of PEL to current production, which will still yield a lower ELF than if the presumption were not rebutted.

Beyond 460 barrels per well day, the demonstrated PEL will turn the exponent into a "net root function," which will tend to offset the advantage to be gained by reducing the difference between one and the ratio of PEL to current production. Although that advantage always outweighs the offsetting effect of the exponent (in other words, it is always worth rebutting the presumption if possible, because doing so reduces the final value of the ELF), the extent to which this happens depends on how what the current average daily production per well is. The higher the production rate, the smaller the net effect is from rebutting the presumption.

The following table illustrates this for four cases: Case 1 has current average production of 500 barrels a day per well; in Case 2 it is 1,000 barrels a day per well; in Case 3, 5,000 barrels a day per well; and in Case 4, 10,000 barrels a day per well, corresponding roughly to the expectations in early 1977 for what would be the situation with the Prudhoe Bay field by the beginning of 1978. 38/

38/ The throughput capacity of TAPS represents a physical constraint on the rate of production from North Slope fields. TAPS had been planned to start up in three phases: the first at a throughput of 600,000 barrels a day; the second and 1.2 million barrels a day; and the third at 1.5+ million. Until the third phase was implemented, TAPS's throughput capacity represented the upper limit at which the Prudhoe Bay field could be produced (Phase 3 would be at or above the maximum efficient rate for Prudhoe Bay of 1.5 million barrels a day). By early 1977 the first two phases had been "telescoped" together, so that TAPS was expected to be at 1.2 million barrels a day by the end of the year. That was, of course, before the fire and explosion at Pump Station 8 while the pipeline was being filled. However, for purposes of analyzing the ELF, the assumptions used by the Legislature and the Administration reflected the planned 1.2 million-barrel-a-day rate of production from the field into TAPS, with approximately 120 producing wells.

PEL	Case 1 (TP=500) ELF	Case 2 (TP=1,000) ELF	Case 3 (TP=5,000) ELF	Case 4 (TP=10,000) ELF
300	0.245372	0.578740	0.909486	0.954370
400	0.157103	0.555743	0.908565	0.954140
450	0.095012	0.542741	0.908095	0.954023
460	0.080000	0.540000	0.908000	0.054000
470	0.063701	0.537208	0.907905	0.953977
500	-0-	0.528509	0.907618	0.953906
600	---	0.495351	0.906644	0.953670
700	---	0.453309	0.905641	0.953430
800	---	0.396362	0.904608	0.953187
900	---	0.308240	0.903544	0.952940
1000	---	-0-	0.902446	0.952690
2000	---	---	0.889149	0.949972

As the table shows, the effect of raising PEL by 100 barrels per well day from its presumed level of 300 is greatest in Case 1, dropping the ELF from 0.245372 to 0.157103. This reduction of 0.088269 in the ELF represents a tax reduction of 35.974 percent as the result of rebutting the presumption (0.088269 is 35.974 percent of the 0.245372 value of the ELF in Case 1 if the presumption is not rebutted). The reduction from similarly raising the PEL from its presumed rate steadily drops off as the rate of current daily production per well gets larger: the ELF is reduced by 0.022997 for the 1,000 barrel-a-day Case 2 (corresponding to a tax reduction of 3.974 percent); by 0.000921 for the 5,000 barrel-a-day Case 3 (tax reduction of 0.101 percent), and by a mere 0.000230 for Case 4 (tax reduction of 0.024 percent), the case approximating Prudhoe Bay as expected after the completion of TAPS start up. In fact, in the Prudhoe-type case, even showing a PEL of 1,000 barrels a day per well (which is about what PEL was then expected to be if the Prudhoe Bay producers had rebutted the presumption) would only reduce the ELF by 0.001680 from its value with the presumed PEL. Rebuttal of the presumption thus represented a potential tax reduction of only 0.176 of one percent.

The decision to rebut or not rebut the presumed PEL is thus seen to have a rule of diminishing returns, the larger the average of current daily production per well becomes. With a property with extremely productive wells, the potential advantage from rebutting the presumption may simply be too small to be worth the effort even though the property is in a high operating cost area of the state.

C. The ELF's Incentive to Continue Development Drilling in "Mature" Fields. Recent (1986) proposals to modify the ELF so that the presumed PEL is on a field-wide or

reservoir-wide basis instead of a per-well basis have overlooked the incentive that the present ELF offers for producers to continue development drilling in mature fields that are already producing at their maximum efficient rate (MER). This incentive is best illustrated by examining a particular example, rather than trying to describe it abstractly.

Suppose there is a field that is producing at its MER, which is 1,500,000 barrels a day, or 45,000,000 barrels in a 30-day month. Since this is the MER for the field, the 45,-000,000 barrel figure will not change if another development well is drilled. Suppose further that there are already 500 producing wells in the field and that the presumption for PEL is unrebutted. What happens to the tax burden if the 501st development well is drilled?

Since the presumption for PEL is in effect, PEL can be replaced in the ELF formula by the expression [300 x WD]. Thus the formula becomes:

$$ELF = \{1 - ([300 \times WD]/TP)\}^{([460 \times WD]/[300 \times WD])}$$

Given how WD is in both the numerator and denominator of the exponent, it cancels itself out and the exponent can be simplified to 460/300. With 500 wells all operating every day in a 30-day month, the number of well days is 15,000. Using the simplified exponent and filling in the variables with the appropriate numerical values from this example, the ELF becomes:

$$ELF = \{1 - ([300 \times 15{,}000]/45{,}000{,}000)\}^{(460/300)}$$

$$= \{1 - (4{,}500{,}000/45{,}000{,}000)\}^{(460/300)}$$

$$= \{1 - (0.1)\}^{(460/300)}$$

$$= 0.850822$$

Now if the 501st well is drilled, the number of well days will become 15,030, and the new ELF will be:

$$ELF = \{1 - ([300 \times 15{,}030]/45{,}000{,}000)\}^{(460/300)}$$

$$= \{1 - (4{,}509{,}000/45{,}000{,}000)\}^{(460/300)}$$

$$= \{1 - 0.100200\}^{(460/300)}$$

= 0.850532

While the difference in the ELF seems small -- a reduction of 0.000290 in the value of the ELF, or 0.034 percent -- its dollars-and-cents effect is not insignificant. If the field is still in its first ten years of production, the nominal tax rate is 15 percent. If it costs $7.00 a barrel to get the oil to market, where it fetches $15.00, the "wellhead" value is $8.00. Assuming a one-eighth governmental royalty interest that is exempt from the Production Tax, the annual tax burden on this field with 500 wells would be:

Tax = (1,500,000 B/D) x (365 days) x (1 - 1/8 tax exempt share) x ($8.00/Bbl) x (15%) x (ELF of 0.850822)

= $489,116,297

Now with 501 wells the tax becomes:

Tax = (1,500,000 B/D) x (365 days) x (1 - 1/8 tax exempt share) x ($8.00/Bbl) x (15%) x (ELF of 0.850532)

= $488,949,583

In this example, drilling the 501st well results an annual savings of $166,714 39/ in the Production Tax. One must remember that the decision to drill each additional development well is a decision that must be made on its own merits. Past expenditures in developing the field may or may not have been good investments, but they are in any event irrelevant to the decision to spend additional money for further development. In contrast, a savings in the future Production Tax burden that will result from the drilling of an additional development well is definitely a factor to be weighed in the decision to drill that additional well or not, and it is one that helps tip the balance in favor of drilling it. Other favorable factors affecting the decision will be the ability to sustain production at the MER for a longer period of time if additional wells are drilled, and the likelihood that the amount of production ultimately

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39/ It should be apparent from the calculation that the exact amount of tax savings to be realized from drilling an additional development well is also dependent on other factors as well, particularly the "wellhead" price. If in the example the market price had been $25 instead of $15, the tax savings would have been considerably greater -- $375,106. Conversely, lower prices would have meant smaller tax savings.

recovered from the reservoir will be greater with more wells, both of which benefit the state as well as the taxpayer.

As this example shows, if the presumption regarding PEL has not been rebutted, all of the incentive provided under the present ELF is due to the fact that the presumed PEL is based on well days, which in turn depends on the number of development wells in operation. 40/ In other words, the only difference between the calculation of the ELF for 500 wells and the one for 501 wells is in the fact that there are 15,000 well days in the first and 15,030 in the second.

40/ It is a slightly different story if the presumption has been rebutted and PEL is established as a fixed number number of barrels per month. There is still an incentive to drill the 501st well, but this time it is due to the fact that the well-days factor still appears in the numerator of the exponent even though it is no longer a factor in PEL (the denominator of the exponent). To illustrate how the ELF provides a drilling incentive when the presumption has been rebutted, let us start with the same figures as in the example in the main text and suppose PEL has been shown to be 9,000,000 barrels per month. With 500 wells the ELF is:

$$ELF = \{1 - 9{,}000{,}000/45{,}000{,}000\}^{(460 \times 15{,}000)/9{,}000{,}000}$$

$$= \{1 - 0.200000\}^{6{,}900{,}000/9{,}000{,}000}$$

$$= 0.842757$$

With 501 wells the ELF becomes:

$$ELF = \{1 - 9{,}000{,}000/45{,}000{,}000\}^{(460 \times 15{,}030)/9{,}000{,}000}$$

$$= \{1 - 0.200000\}^{6{,}913{,}800/9{,}000{,}000}$$

$$= 0.842469$$

In this example the difference in the ELF between having 500 producing wells and 501 is 0.000288. It is coincidental that this figure comes out so close to the difference in the ELF from drilling the 501st well in the example in the main text with the unrebutted presumption about PEL. The point being made here is that, if the presumption is rebutted, the present ELF still provides an incentive to drill another well.

APPENDIX A

A Review of How Exponents Work

Exponents can be sorted into two kinds: whole numbered exponents (1, 2, 3 etc.) and fractional exponents (1/2, 1/3, 2/3 etc.). The whole numbered exponents are the easiest to understand. Basically, a whole numbered exponent states how many times a particular number is to be multiplied by itself. For example,

$$4^3 = 4 \times 4 \times 4, \text{ and}$$

$$6^7 = 6 \times 6 \times 6 \times 6 \times 6 \times 6 \times 6.$$

Whole number exponents are often called "powers" -- in the two examples above, the first is four to the third power, the second is six to the seventh power.

Now suppose we want to multiply two numbers together, each of which is some power of the same number. What happens? Suppose we want to take four to the third power and multiply it by four to the second power. We already know that four to the third power is four times four times four, and four to the second power similarly is four times four. Thus,

$$\begin{aligned} 4^3 \times 4^2 &= (4 \times 4 \times 4) \times (4 \times 4) \\ &= 4 \times 4 \times 4 \times 4 \times 4 \\ &= 4^5 \end{aligned}$$

Notice that the exponent, 5, in the last line equals the sum of the two exponents, 3 and 2, of the numbers being multiplied together. One may draw from this example the following generalization: if a number, A, to the N-th power is multiplied by A to the M-th power, the product is A to the "N plus M"-th power, or

$$A^N \times A^M = A^{(N + M)}$$

(Remember, though, that it must always be the same base number that is being taken to the different powers and mul-

tiplied together, for this generalization to be true. A to the N-th power times B to the M-th power does not equal A times B taken to the "N plus M"-th power, nor does it equal just A to the "N plus M"-th power or B to the "N plus M"-th power. As a generalized statement, A to the N-th power times B to the M-th power equals A to the N-th power times B to the M-th power, and that's as simple as the statement can be made and still be a generalized statement. In limited kinds of cases it can be made into a simpler statement, but only when there are special values for A and B or special values for M and N, or both.)

Exponents have a similar property when division is involved instead of multiplication. Suppose we wish to divide five to fifth power by five to the third power (the third power of a number is called its "cube"; five to the third power is "five cubed"). The following shows what happens:

$$\frac{5^5}{5^3} = \frac{5 \times 5 \times 5 \times 5 \times 5}{5 \times 5 \times 5}$$

$$= \frac{\not{5} \times \not{5} \times \not{5} \times 5 \times 5}{\not{5} \times \not{5} \times \not{5}}$$

$$= 5^2$$

Note that the exponent of the answer equals the difference between the exponent in the dividend (five to the fifth) and that in the divisor (five cubed). The generalization to be drawn from this example is that, when different powers of the same number are divided into each other, the exponent in the result equals the difference between those powers:

$$\frac{A^N}{A^M} = A^{(N - M)}$$

This generalized equation gives meaning to two special cases: the numbers one and zero when used as exponents. If N equals M plus one, then:

$$A^1 = A^{(N - M)}$$

$$= \frac{A^{N}}{A^{M}}$$

$$= \frac{A^{(M+1)}}{A^{M}}$$

$$= \frac{A^{M} \times A}{A^{M}}$$

$$= A$$

Thus, any number to the first power equals that number. (The preceding demonstration does not apply when A equals zero, because it would involve dividing by zero; however, the generalization still applies in the case of zero, so that zero to the first power is zero.)

Now, to get the zero-th power, N and M must be equal, and then the following happens:

$$A^{0} = A^{(N-M)}$$

$$= \frac{A^{N}}{A^{M}}$$

$$= \frac{A^{N}}{A^{N}}$$

$$= 1$$

Therefore, any number (except zero itself) raised to the zero-th power equals one.

Now, what happens if a number being raised to some power is itself the power of another number? For example, four is two to the second power (the second power of a number is its "square"; two to the second power is "two squared"). What is four cubed if it is converted into powers of two?

$$4^3 = 4 \times 4 \times 4$$

$$= (2^2) \times (2^2) \times (2^2)$$

$$= (2 \times 2) \times (2 \times 2) \times (2 \times 2)$$

$$= 2 \times 2 \times 2 \times 2 \times 2 \times 2$$

$$= 2^6$$

In other words,

$$\left[2^2\right]^3 = 2^6$$

Notice that the exponent 6 in the answer equals 2 times 3. Once again this example gives rise to a generalization: if the quantity, A to the N-th power, is itself raised to the M-th power, the result equals A to the "N times M"-th power:

$$\left[A^N\right]^M = A^{(N \times M)}$$

When a number is raised to the N-th power, we are asking what the product is of multiplying one by that number N times. The N-th root of a number works the other direction. For a given number, it asks what number, when raised to the N-th power, will yield that given number. Thus, two is the cube root of eight, because two cubed (i.e., two times two times two) equals eight.

To show the N-th root of a number (call it A), the exponent is the fraction 1/N. The reason for having 1/N as the exponent to show the N-th root of a number is as follows: Let R stand for the N-th root of A. then by definition R to the N-th power equals A, or in mathematical terms:

$$R^N = A$$

Now let X stand for the exponent applied to A that is to be used to signify the N-th root of A; In other words, A to the X-th power equals the N-th root of A, which is R. In mathematical terms again, this is:

$$A^{X} = R$$

Substituting A to the X-th power in the second equation above gives the following:

$$R^{N} = \left[A^{X}\right]^{N} = A$$

Just a little bit above we showed that if the N-th power of a number is itself taken to the M-th power, the result equals that base number taken to the "N times M"-th power. Hence,

$$\left[A^{X}\right]^{N} = A^{(X \times N)} = A^{1} = A$$

Since A to the "X times N"-th power equals A to the first power, then the exponents, although expressed differently, must be equal. So, X times N equals one. Therefore, X equals one divided by N, or 1/N. Since R, the N-th root of A, equals A to the X-th power, and since X equals 1/N, then R equals A to the "1/N"-th power. Q.E.D.

It is now but a simple step to understand what fractional exponents do. If the exponent is a fraction, M/N, it simply means that the N-th root of the base number is found and then that root is raised to the M-th power, or alternatively, that the base number is first raised to the M-th power and then the N-th root is taken. In mathematical terms:

$$A^{(M/N)} = A^{[(1/N) \times M]} = \left[A^{(1/N)}\right]^{M}$$

or

$$A^{(M/N)} = A^{[M \times (1/N)]} = \left[A^{M}\right]^{(1/N)}$$

It does not matter which is done first, taking the N-th root or raising to the M-th power, as a brief example will show. Suppose we want to take eight to the two-thirds power. The cube root of eight is two, which when squared equals four. Now, reversing the order between taking the root and raising

to the power, the square of eight is 64; the cube root of 64 is four. Both ways, the answer is four.

Fractional exponents expressed in decimal terms are no different from any other fractional exponent. Thus,

$$A^{0.125}$$

is simply the 125th power of the 1,000th root (or equivalently, the 1,000th root of the 125th power) of A. If, as here, the fraction can be simplified (0.125 equals 1/8), there is no change in the result if the simpler fraction is substituted (nor would there be if a less simple form of the same fraction were substituted for a simple one). The 125th power of the 1,000th root of A is exactly equal to the eighth root of A:

$$A^{0.125} = A^{(1/8)}$$

ELF BRIEFING BOOK

BP EXPLORATION (ALASKA) INC.

MARCH 17, 1989

EXECUTIVE SUMMARY

- Proposed changes to the ELF incentive are not designed to promote development of marginal fields. Their sole purpose is to increase taxes on Prudhoe Bay and Kuparuk so the governor can sustain state spending at 4-1/2 times the national average. At no time has the governor mentioned reducing state spending, even though the public overwhelmingly has supported substantial budget cuts during recent budget workshops held throughout Alaska. According to an internal memo from Gregg Erickson, his own chief economist, state government grew by more than 1,300 employees between November 1987 and November 1988. State government salaries and benefits also increased during the same period, while private-sector wages and benefits declined.

- While oil accounts for a third of Alaska's gross state product, it provides 85% of state government revenues. Alaska's severance tax on Prudhoe Bay oil is more than 12% -- nearly the highest in the U.S. With proposed changes to ELF, the rate would be nearly 15% -- by far the highest in the nation. According to the state's October revenue projections, the state currently receives 50% of the net profits from North Slope production.

- For every $1 BP Exploration has earned from North Slope production over the last three years, it has paid the state $1.40. During that period, the state has collected more than $2 million a day in taxes and royalties from BP Exploration; BP Exploration's after-tax profit has been less than $1.5 million a day. Since production began at Prudhoe Bay, the industry has paid the state nearly $30 billion in taxes and royalties.

- Over the last three years, BP Exploration has reinvested 80% of its production profits in North Slope exploration and development. It plans to invest between $2 billion and $2.5 billion over the next five years, which should facilitate the recovery of an additional 750 million barrels of oil for the state to collect royalties on and tax. This investment is creating jobs for Alaskans and revenues for state government. Hurl State is an example of a marginal development inside the Prudhoe Bay field. Facilities are being designed, fabricated, transported and installed in Alaska, by Alaskans. The $80 million project is generating some 300 construction jobs and will increase recovery from Prudhoe Bay by 37 million barrels. ELF is working as intended: it encourages marginal projects like Hurl State at Prudhoe Bay and Kuparuk.

- The 20-cent-per-barrel impact of ELF referred to by the governor (BP calculates the impact to be 25 cents) represents more than 10% of the oil industry's after-tax profits from North Slope production (which averaged $1.48 per barrel, according to state figures).

- Recently Gregg Erickson has based the state's and industry's shares of revenues from oil production on $18-per-barrel oil; $18 oil would increase state revenues $700 million a year over current projections -- enough to cover even the governor's $2.3 billion budget.

"ELF" OVERVIEW

PRESENT ELF

- More profitable fields should pay a higher rate of tax than less profitable ones.
- ELF is based on the percentage of a field's production not needed to cover direct operating costs -- this non-cost percentage represent potential profit.
- The higher the "profit percentage," the higher the tax is under the present ELF. This reflects the higher profitability of a field having a high "profit percentage."
- Marginal fields have a very low "profit percentage." By being based on this percentage, the ELF lowers the tax rate for marginal fields. When all of the production is needed to cover direct operating costs, the "profit percentage" is zero and the ELF equals zero, so there is no tax. This in fact happened for Milne Point, which had zero production tax during the last part of the time it was in production.

PRPPOSED ELF (HB 118 AND SB 97)

- Field size, not profitability, would become the dominant factor in the ELF.
- With field size as the dominant factor, the ELF would create an incentive to keep small fields small. For example, adding 1,000 B/D to a 100,000 B/D field would increase the tax rate not only on the additional 1,000 B/D, but on the the 100,000 B/D as well.
- Relying on field size would create an incentive to make large fields smaller. For example, cutting 1,000 B/D from a field producing 1,500,000 B/D would give a tax break to all of the remaining 1,499,000 B/D.
- Two fields could have exactly the same profit, but the larger one would pay more tax.

	Field A	Field B
Number of Wells	500	5,000
Total Production (B/D)	151,000	1,501,000
Production Needed to Cover Costs (300 B/D per well)	150,000	1,500,000
PROFIT (B/D)	1,000	1,000
PROFIT PER DAY (@ $7.36/B)	$7,360	$7,360
SB 97 - TAX PER DAY	$ 330	$ 593,461
HB 118 - TAX PER DAY	$1,016	$1,170,652

ELF AND PROFITABILITY

The ELF is designed so that more profitable fields pay a higher tax rate than less profitable fields. The way the ELF does this is by looking at what percentage of a field's production is needed to cover the basic operating costs to get that production out of the ground. This "cost percentage" is then subtracted from 100% to find the percentage of production that represents potential profit. The ELF is based directly on this "profit percentage." A high "profit percentage" reflects a high degree of profitability. So, the higher the "profit percentage" is, the higher the tax rate is.

ELF AND FIELD SIZE

The present ELF does not ask how large a field is -- all the ELF needs to know is what percentage of a field's production represents potential profit. This is because the ELF reflects the principle that more profitable fields should pay higher taxes, and less profitable fields should have lower rates.

Field size is not a reliable indicator of whether a field is profitable or not. For example, the McArthur River field in Cook Inlet has paid back more for each dollar invested in it than Prudhoe Bay has, even though McArthur River is only 1/20 the size of Prudhoe. At the other extreme, the West Sak field is very large. But it is at least as marginal as Milne Point, which is only a fraction of West Sak's size.

The ELF avoids messy questions of whether a large field is as profitable as a small one. Instead, it goes straight to the heart of the question. How much of the production from a field, large or small, is needed to cover its operating costs, and how much represents potential profit? The higher the "profit percentage," the higher the ELF is and the higher the tax rate becomes for that field.

HOW ELF WORKS

The ELF is just a number between zero and one that is multiplied times a base tax rate. This number is found by looking first at what percentage of a field's production is needed to cover the basic operating costs to get that production out of the ground.This "cost percentage" is subtracted from 100% to find the percentage of the production that represents potential profit.

For gas, this "profit percentage" is the ELF. In other words, if 75% of a field's gas production represents potential profit and only 25% is covering basic operating costs, then the ELF for that field is 0.75. For oil, the profit percentage is raised to an exponent, and the result equals the ELF.

In the case of this hypothetical gas field with an ELF of 0.75, the tax rate would equal 0.75 times the base rate of 10%, or 7.5 percent.

If an oil field has an ELF of 0.75, the actual tax rate will be 0.75 times the base tax rate for oil, which is 12.25% during the first five years of production and is 15% thereafter. So, if the field is still in its first five years, its actual tax rate will be 0.75 times 12.25%, or 9.1875 percent. If the five years had already passed, the rate would be 0.75 times 15%, or 11.25 percent.

ELF AND MARGINAL FIELDS

A marginal field is simply one where most or all of its production is needed to cover the operating costs of getting that production out of the ground. All fields -- no matter how profitable they may be at the beginning -- become marginal eventually.

The ELF automatically takes care of fields as they become marginal, because it starts with the percentage of production that is needed to cover the operating costs. If this "cost percentage" is high (as it would be when the field is getting marginal), the remaining percentage of the production representing potential profit is small. The ELF is based directly on this "profit percentage," so a small "profit percentage" means the ELF is small. A small ELF means a low tax rate.

As more and more of the production is needed to cover operating costs, the ELF gets smaller and smaller and the tax rate gets lower and lower. When all of the production is needed to cover operating costs, the "profit percentage" is zero and there is no tax at all.

ELF AND PRUDHOE BAY

Because of tax legislation in 1981, a rule was added to the ELF statute which says that if the ELF is more than 0.7 for a field, the ELF is to be "rounded" up to one (1.0). In other words, this rule assumes that 100% of such a field's production represents potential profit and none of it is needed to cover operating costs. Such an assumption is not realistic, of course, because a field never has operating costs of zero.

Since a field always has some operating costs in the real world, this "rounding" rule is only applied during the first ten years of a field's production. After that, the ELF goes back to being based on the actual percentage of production that represents potential profit over and above the basic operating costs. Prudhoe Bay had its tenth anniversary in June 1987, and so the ELF went back to being based on Prudhoe Bay's actual percentage instead of the artificial assumption that 100% of its production represents profit.

ELF AND MILNE POINT

The ELF worked at Milne Point. Conoco was able to show the Department of Revenue that the costs of operating Milne Point were greater than the value of all of its production. As a result the "profit percentage" in the ELF formula was zero for Milne Point, and there was no production tax at all during the last half of the time it was in production.

The ELF can only reduce the production tax for a field; it cannot subsidize that field. Reducing the tax to zero was as much as the ELF could do to help Milne Point. What shut that field down was a combination of low oil prices and the unusually high royalty rate which that field suffers from.

ELF AND THE STATE'S FAIR SHARE

When Alaska's oil and gas tax laws were last overhauled in 1981, there was a consensus of the legislative leadership and the administration that the State's "fair share" of the oil wealth should not be less than 30 percent. This corresponded with a rough one-third, one-third, one-third division of that wealth among the three parties interested in it -- the oil companies, the State of Alaska and the IRS. Thirty percent was as far below Alaska's one-third share as the political leaders were willing to accept.

From 1981 through June 1987, the State's share was always more than 30 percent. This is based on studies by the Department of Revenue.

Since June 1987, when the ELF "rounding" rule expired for Prudhoe Bay, the State's share has still been above 30 percent. Based on the present official price forecast of $7.36 for FY 89, the State is currently receiving almost half (49%) of the well-head value of the oil after lifting costs and depreciation are taken out. The industry's share is 34 percent. Even with the Cowper Administration's numbers (which are based on a value in Valdez), Alaska's share is 36 percent.

ELF AND THE BILLION DOLLARS "LOST" SINCE 1981

In 1981 Alaska repealed its separate-accounting income tax, which was under constitutional attack in court, and replaced it with the present income tax, which uses a modified apportionment formula to determine taxable income earned in Alaska. To offset most of the loss in income tax revenue from this change, the oil production tax was increased.

On June 22, 1981 Mr. Donaldson of SOHIO testified to the Free Conference Committee about the bill that was enacted two days later. He said it represented a "94:6 division of the dollars at risk" under separate accounting (transcript, p.44, line 1; see also p.43, lines 8-18). The fiscal note prepared in 1981 by the Commissioner of Revenue indicated that, in FY 82 - FY 85, the State would receive over 98% of the revenues it would have received if it kept separate accounting.

According to testimony this year by the Department of Revenue to the House Resources Committee, the State has collected a total of $9.208 billion in income tax and production tax from the oil industry in FY 82 - FY 87, versus $9.878 billion [1] that it would have collected under separate accounting during that time. In other words, the State has gotten 93.2% of the income tax and production tax revenue that it would have received if it had gambled and stayed with separate accounting. This is very close to Mr. Donaldson's figure of 94%, although it is five percentage points short of the Commissioner's estimate of 99 percent.

To keep these variances in perspective, it is worth remembering that the "lost" billion (or $670 million, to be more accurate) is a cumulative figure over a six-year period. Petroleum revenue forecasting simply cannot have a high degree of accuracy over such a long period of time, except through good luck. Even the current official revenue forecast has a range of more than $2.1 billion between the "low" and "high" cases for FY 89 - FY 91, which is only a three-year period.

ELF AND GOVERNOR COWPER

The ELF goes back a long way. It was enacted in 1977 and took effect within two weeks of the start-up of Prudhoe Bay. Except for those two weeks, there has always been an ELF for Prudhoe Bay.

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[1] While the Department of Revenue claims the "loss" is $1,002 million, it acknowledges that the "loss" would have been $670 million in FY 82 - FY 87 if the federal Windfall Profit Tax had been allowed as a deduction under separate accounting. In 1981 the Department of Law was strongly recommending the allowance of a Windfall Profit Tax deduction in determining taxable net income from Alaska production, or else the likelihood of losing the lawsuit over separate accounting would have been materially increased. The figure of $9.878 billion in the text equals the $9.208 billion that was actually collected, plus the $0.670 billion that would have been collected under separate accounting with a Windfall Profit Tax deduction.

Back in 1977 Governor Cowper was Chairman of the House Finance Committee. His committee held intensive hearings on the ELF formula. After considerable examination of alternative formulas (including polynomials), he recommended the addition of an exponent to the formula, so that it was basically the same ELF formula as the one on the books today. The only difference is, his formula had 300 in the exponent instead of 460. This is what he said back then about the ELF:

> Given the tax relief that the administration's severance tax proposal will afford the economically marginal oil and gas fields and the relatively modest increase in taxation the proposal places on the highly productive and profitable oil and gas fields, House Finance Committee Substitute for CS for SB 238 represents a balanced and reasonable adjustment to the present tax law.

The ELF formula has not been changed since its enactment in 1977.

PROFITABILITY, REINVESTMENT SINCE PRICE DECLINE

BP EXPLORATION (ALASKA), INC.:

- Currently owns 47% of North Slope oil production (41% net of State's royalty oil).
- Over the last 3 years, BP Exploration has reinvested over 80% of its profits back into North Slope production and exploration.
- Over the last 3 years, BP has paid the State an average of $214 million more per year in taxes and royalties than it has earned. For every $1.00 BP has earned it has first paid the State $1.40.
- Over the next 5 years, BP Exploration expects to invest $2.0 billion to $2.5 billion and allow the production of an additional 750 million barrels - almost all at Prudhoe Bay and Kuparuk.

	$ MILLIONS			
	'86	'87	'88	AVG
After Tax Income	$140	$909	$560	$536
Payments to State	$604	$897	$751	$750
Capital and Exploration Costs	$698	$278	$341	$438

- BP's pipeline interest has additional profits which are dictated by a settlement agreement signed by the State of Alaska and the pipeline owners. BP's pipeline interest also pays additional Alaska taxes.

$ MILLIONS

	Production Tax	Royalty[1]	Income Tax	Property[2] Tax	Totals
1986	272	216	22	94	604
1987	394	365	58	80	897
1988	297	300	59	95	751
TOTALS	963	881	139	269	2,252
				AVERAGE	750

(1) A portion of the royalty payment goes directly to the Permanent Fund.

(2) A portion of the property tax goes to municipalities or boroughs.

Supplementary Information on Oil and Gas Exploration, Development and Production Activities

This section provides information specified by Statement of Financial Accounting Standards No. 69 (FASB 69), "Disclosures about Oil and Gas Producing Activities."

Three general disclosure areas comprise the information in this section. The first area provides historical information about costs and revenues, including the Company's aggregate recorded investment in oil and gas properties, annual costs incurred and a separate statement of the results of operations for producing activities. The second area contains the Company's petroleum engineers' quantity estimates for proved oil and gas reserves and the major factors causing changes in these reserve estimates. The final area of disclosure assigns a monetary value to proved reserve quantities and changes therein using a standardized formula as specified in FASB 69.

The Company has provided additional commentary throughout this section that is important for a proper understanding of the nature of the data provided and its inherent limitations.

Historical Information

Millions of Dollars	1987 Total	1987 Alaska	1987 Lower** 48 States	1986 Total	1986 Alaska	1986 Lower** 48 States
Capitalized Costs at December 31						
Proved properties	$13,374	$10,879	$ 2,495	$11,000	$ 8,471	$ 2,529
Unproved properties	802	112	690	837	95	742
	14,176	10,991	3,185	11,837	8,566	3,271
Accumulated depreciation, depletion and amortization	4,770	3,506	1,264	4,074	2,798	1,276
	$ 9,406	$ 7,485	$ 1,921	$ 7,763	$ 5,768	$ 1,995
Costs Incurred (capitalized or expensed)						
Acquisition of properties*	$ 27	$ —	$ 27	$ 33	$ 2	$ 31
Exploration	239	47	192	321	35	286
Development	665	317	348	1,128	810	318

*Excludes $1,953 million of purchase price premium allocation, arising from the 1987 acquisition of the minority interest in Standard Oil.
**Foreign costs are included in Lower 48 States.

231 Capital

668 Capital

Results of Operations for Producing Activities

The following summarizes the "Results of Operations for Producing Activities," as defined by FASB 69, for the years ended December 31, 1987 and 1986. As specified, financing costs are not included in this summary.

Income taxes are included in the results and were computed under FASB guidelines using statutory tax rates, while considering the effects of permanent differences and tax credits relating to oil and gas producing activities.

Millions of Dollars	1987 Total	1987 Alaska	1987 Lower* 48 States	1986 Total	1986 Alaska	1986 Lower* 48 States
Revenues from the sale of oil and gas						
To third parties	$3,450	$3,206	$ 244	$2,070	$1,894	$ 176
To affiliates	178	134	44	116	79	37
	3,628	3,340	288	2,186	1,973	213
Production costs	1,220	1,051	169	942	815	127
Depreciation and depletion	1,009	860	149	814	648	166
Exploration expenses						
Geological and geophysical	32	1	31	31	1	30
Amortization of unproved properties	91	9	82	601	113	488
Dry hole costs	81	3	78	223	55	168
Other	119	58	61	160	21	139
Total exploration expenses	323	71	252	1,015	190	825
Unusual items	—	—	—	283	72	211
Income (loss) before interest, income taxes, minority interest and extraordinary item	1,076	1,358	(282)	(868)	248	(1,116)
Income taxes	493	611	(118)	(413)	108	(521)
	$ 583	$ 747	$ (164)	$ (455)	$ 140	$ (595)

*Foreign operations are included in Lower 48 States.

STANDARD OIL PRODUCTION COMPANY

Supporting Schedule C (1)

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES - 1988

($ Millions)

	TOTAL	ALASKA	LOWER 48	FOREIGN
Revenues from the sale of oil and gas:				
Sales to third parties		358.0		
Sales to affilliates		4,190.3		
Transportation costs		(1,836.3)		
Royalty expense		(188.7)		
Total netback revenue	0.0	2,523.3	0.0	0.0
Production costs		998.1		
Depreciation & Depletion		877.1		
Exploration expenses:				
Geological and geophysical		3.5		
Amortization of unproved properties		4.8		
Dry hole costs		0.3		
Other - cash		4.1		
Other Non-cash		1.7		
Total exploration expenses (a)	0.0	14.4	0.0	0.0
Unusual items				
Income before interest, income taxes and extraordinary items (b)	0.0	633.7	0.0	0.0
Income taxes on U.S. basis (U.K. Basis = 258.9)		290.4		
	0.0	343.3	0.0	0.0

(a) Amounts should tie to totals on Schedule C (3).

(b) Must equal U.S. GAAP Operating Income for SOPC, Excluding Alaska Pipelines and Gas Marketing Activities, as reported to BP America Control Reporting during the year end 1988 financial close.

$ MILLIONS

	1986	1987	1988
Income Before Income Tax	$ 248	$1,358	$ 634
Add: Depreciation from BP purchase	0	162	216
Adjusted Income Before Income Tax	248	1,520	850
Income Tax	(108)	(611)	(290)
INCOME	$ 140	$ 909	$ 560

OIL TAXES: WHAT HAPPENED IN 1981

Background

The 1981 oil tax legislation responded to a legal challenge to the constitutionality of Alaska's separate accounting income tax, which had been enacted in 1978. By 1981, about $2 billion had been collected under separate accounting, and future revenue under that tax was projected to be about a billion dollars a year. The litigation was expected to go to the U.S. Supreme Court, with the final outcome in 1985 or '86. By then, if the State lost, the potential tax refund could have been $6 billion or more, with several billion more in interest. Even with the much higher oil price forecasts of that time, such a huge refund would have been more than the State's entire projected annual revenue.

Two U.S. Supreme Court decisions in 1980 (Mobil Oil v. Vermont and Exxon v. Wisconsin) had increased the legal doubts about the validity of separate accounting. In both cases, a large multinational oil company had sought to have separate accounting applied, and in both cases the Supreme Court said no. In rejecting the oil companies' arguments, the Court made some gratuitously critical comments about separate accounting, noting in one case that it was "theoretically incommensurate" with apportionment, the tax method that the Court was upholding.

The State's Fair Share

In March 1981 the leadership of the House and Senate made a joint statement with the Governor, declaring that Alaska's fair share should not be less than 30% of the value represented by the oil. This consensus figure reflected the perception that there were three parties with interests in that money -- the oil companies, the State of Alaska, and the IRS. Roughly split three ways, a fair share would be one third, or 33 percent, to each party. The 30% figure was as far below the one-third share as the State's political leaders were willing to go.

The Options in 1981

The Legislature considered three basic options in 1981 -- a "back stop" reserves tax, a "settlement" package of legislation that would end the lawsuit over separate accounting, and legislation to stop the State's financial exposure from continuing to grow year by year while the lawsuit was pending. A fourth potential option -- to do nothing -- was generally seen as unacceptable gamble with the public's money.

The "back stop" reserves tax proposal was developed jointly by the Administration and the House, particularly the House Oil and Gas Committee. Under this proposal, a new property tax on oil and gas reserves would be enacted, and this new tax would be as large or larger than the separate accounting revenue. Each taxpayer's liability under separate accounting would give rise to a dollar-for-dollar credit against the reserves tax. If a refund was made for separate accounting, the credit against the reserves tax would shrink accordingly. Thus the reserves tax liability would increase to offset a refund for separate accounting.

The "settlement" idea was developed by Senator Dankworth in the course of discussions with industry, particularly Exxon. Under this approach, the State would repeal separate accounting after 1981 and replace it with apportionment, using a specially modified apportionment formula. There would also be an investment tax credit, not limited to the oil industry, for new investments in Alaska. In its final version, the "settlement" bill would have given the State about 70% of the revenue it would get if it kept separate accounting.

The "limit the exposure" idea arose during the Free Conference Committee's hearings on SB 524 after it became clear that Senator Dankworth's "settlement" bill would give up too much revenue to be politically acceptable. This bill, which is what passed, also repealed separate accounting after 1981 and replaced it with the same modified apportionment formula. To offset most of the reduction in income tax revenue, the severance tax was increased from 12.25% to 15% and a "rounding" rule was adopted for the ELF. Under this rule, if the ELF under the statutory formula was more than 0.7 during the first 10 years of a field's production, it was "rounded" to one (1.0). The Free Conference Committee received testimony that this option would give the State about 95% of the revenue it would get if it kept separate accounting.

The bills for all three options contained certain retroactive amendments to the separate accounting statutes, to remove potentially prejudicial side issues from the litigation. The most notable was the allowance of a deduction for the Windfall Profit Tax, the federal tax on oil that rose in price as the result of its release from price controls. Legal opinion then was that such a deduction was necessary or else the State's chances of winning on separate accounting would be significantly reduced.

What Happened

The Free Conference Committee on SB 524 first met on June 11, 1981. The next day the "coup" in the House took place, and the House reorganized itself from June 12th through the 16th. When the Committee reconvened on June 22nd, its membership from the House had been changed. After hearings on the 22nd and 23rd, it adopted its committee substitute on June 24th. Both houses passed it the same day.

The Results

According to a 1985 study by the Department of Revenue, the State received more than 30% of the oil value each year from FY 82 through FY 85. Public (non-oil company) information shows the percentages were over 30% for FY 86 - FY 88. As for the "lost" billion dollars (really $0.67 billion with the Windfall Profit Tax deduction under separate accounting) in the FY 82 - FY 87 period, the Administration's own numbers today show that Alaska has received over 93% in production tax and income tax revenues as it would have if separate accounting had been kept ($9.208 billion vs. $9.878 billion).

ADMINISTRATION ARGUMENTS

ADMINISTRATION	BP EXPLORATION
• The industry is not paying its fair share.	Over the last 3 years, every $1.00 that BP Exploration has earned from North Slope production, it has first paid $1.40 to Alaska. The industry accounts for 85% to 90% of the state's revenues.
• The industry is not reinvesting its profits.	Over the last three years, BP Exploration has reinvested 80% of its production profits in Alaska.
• Pipeline profits are too high and therefore the production tax should be increased (by changing the ELF).	Pipeline profits are regulated by the FERC settlement agreement signed by the State of Alaska and the industry. The rate of return is currently 6.4%.
• The industry is drilling extra wells and running wells at short intervals to take advantage of ELF.	Each well drilled is approved by the Alaska Oil and Gas Conservation Commission. There is no advantage to running wells for short periods - regulations are based on per hour operation. Hundreds of wells were drilled with constant 15% rate.
• Industry testified against the ELF in 1977.	Industry testified against a rate increase from 8% to 12.25%. The quotes are out of context.
• State is not getting as much as Indonesia with less production.	Per ARCO, the wellhead price was $17.50 in Indonesia vs. $6.93 in Alaska in 1987. This price difference accounts for the difference, not industry profitability.
• Milne Point closed because of a high production tax.	When Milne Point shut-in, its production tax was 0%. Its effective royalty was over 18%.

ADMINISTRATION ARGUMENTS (continued)

ADMINISTRATION	BP EXPLORATION
• Using $18 ANS, the state share is only 29%.	This figure includes pipeline income. It also increases state revenue by $700 MM vs the fall revenue forecast. The $139 million from ELF should not be needed.
• The current rate is too low.	The current rate at Prudhoe is within 1% of being the highest in the nation by far.
• The state has lost $1 billion from the 1981 legislation.	The actual number is $670 million (assuming a deduction for windfall profits tax). This is 93.2% of neutrality. Sohio had testified it would be 94%.
• The oil industry is enjoying great profits and should pay more tax.	No other state is proposing major oil tax increases. The federal government is considering tax incentives for what it considers an ailing oil production industry.

STATE: **The current tax rates at Prudhoe Bay and Kuparuk are too low. Neither is on decline - why should the rate be reduced.**

INDUSTRY: Formerly, Prudhoe Bay was capable of producing well above its maximum economic rate of 1.5 million barrels per day. Currently, the capability to produce above that rate has dropped significantly.

The tax rate should tie to profitability not productivity. PBU has produced for 12 years in the harshest climate in the world. Maintenance costs are skyrocketing, prices are down. Avoiding decline was automatic in 1981 - it is extremely expensive in 1989. The field would decline at 20 percent per year if investment stopped. Do not give the industry incentives to hasten and to steepen decline.

STATE: **The current tax rates at Prudhoe Bay and Kuparuk are too low. They are immensely profitable and can afford to pay more. The industry is taking $12mm per day out of the State (net of reinvestment).**

INDUSTRY: Over the last 3 years, BP Exploration has reinvested over 80 percent of its North Slope production profits. Our capital budgets over the next 5 years are estimated to total between $2.0 and $2.5 billion and are expected to allow the production of an additional 750 million barrels.

The State is apparently saying that we are taking out $12 million per day. Our own figures, shown below, put the number at under $1 million per day.

The closest we can get to the basis of the $12 million per day is from G. Erickson's presentation in House Resources where he determined the cash flow to be $5.46 per barrel which would total about $11 million per day. This $11 million more or less will reconcile to our figures noting the following differences:

- About $6 million per day is depreciation. Depreciation is simply recovery of capital invested in the field. We could have put the money in the bank. The State's position is you never get your deposit back.

- About $2.0 million is pipeline profits. Pipeline profits are dictated to the industry by the FERC settlement agreement which the State of Alaska and the pipeline owners signed.

- About $.5 million is federal income tax. The Erickson presentation uses a rate under 34 percent. On a cash basis our federal taxes in the future will exceed 34 percent because our tax depreciation will be significantly less than book depreciation.

- About $1.5 million is a difference in price. Our average price over the last 3 years is between $1.50 and $2.00 lower than OMB's price. Therefore, our actual profits are less.

$ MILLIONS

BP Exploration (Alaska) Inc.	'86	'87	'88	AVG
After Tax Income	$140	$909	$560	$536
Payments to State	$604	$897	$751	$750
Capital and Exploration Costs	$698	$278	$341	$438

- Income minus investment is $98 million per year, less than $1/2 million per day for 47 percent of the production. Industry wide the figure would be under $1 million.

STATE: **The current tax rates at Prudhoe Bay and Kuparuk are too low. They are immensely profitable and can afford to pay more. The State is not getting its fair share.**

INDUSTRY: From 1981 through June 1987, the State's share was always more than the 30 percent fair share level. This is based on studies by the Department of Revenue.

Since June 1987, when the ELF "rounding" rule expired for Prudhoe Bay, the State's share has still been above 30 percent. Based on the present official price forecast of $7.36 for FY 89, the State is currently receiving almost half (49%) of the wellhead value of the oil after lifting costs and depreciation are taken out. The industry's share is 34 percent.

Over the last 3 years - for every $1 BP Exploration has earned after tax, it paid the State of Alaska $1.40.

BP Exploration (Alaska) Inc.	'86	'87	'88	AVG
After Tax Income	$140	$909	$560	$536
Payments to State	$604	$897	$751	$750

The current contention by OMB that the number is 29 percent is based on $18 oil. That price is $5.11 higher per barrel than the FY 1990 mid-price forecast in October. With this price, state revenues would jump by about $700 million in FY 90. Presumably, the extra $700 million will more than offset the extra $100 million for the proposed ELF change.

Without more detail, it is impossible to check the OMB figures, although there probably is pipeline income included. Pipeline income should be excluded because severance tax is a tax on production and not transportation. Also, the income earned on the pipeline is dictated by the FERC settlement agreement which the State of Alaska signed along with members of the industry.

Based on the Department of Revenue's October Forecast, the industry is making $1.48 per barrel from its production activities. Compared to $1.48, a 25¢ tax increase, even after federal income tax effects, is a significant amount.

STATE: **The current tax rates at Prudhoe Bay and Kuparuk are too low. They are immensely profitable and can afford to pay more. Foreign countries and other states get far more than Alaska and the U.S.**

INDUSTRY: Over the last three years, for every $1 BP Exploration has earned after tax, they have first paid the State $1.40.

Prudhoe Bay's current production tax rate is within 1 percent of the highest rate in the U.S. Passage of SB 97 or HB 118 would give Prudhoe Bay the highest rate in the nation by almost 2 percent.

The costs in Alaska are far higher per barrel than foreign countries. The production costs are several dollars higher. There is a pipeline charge of over $3 and there is high cost Jones Act water transportation.

Second, foreign nations often grant concessions to large areas of land, instead of making it available in much smaller, leased parcels as Alaska does.

Third, the regime in many foreign nations allows the oil company to recover its exploration costs and some or all of its development costs before the host government starts taking its share. That means that the State would have received no taxes or royalties until the industry had recovered its $30 billion plus investment. This is very different from leasing on a bonus-bid basis, which has been the method primarily used by Alaska.

The most nearly comparable situation in Alaska is its net profits share leases. Under those leases, the State's net profits share does not start to be paid until the lessee has recovered its developments costs, plus a reasonable rate of return on its investment. The rate of return was specified by the State when it put the lease up for bid. For one lease at Endicott, SOHIO and three Alaska Native Regional Corporations bid a net profits share of over 79 percent for the State. Once the development costs and return are recovered, the State's share of the "economic rent" from this lease will be very comparable to that of the United Kingdom for properties in the North Sea that have similarly paid off their investments.

STATE: **The current tax rates at Prudhoe Bay and Kuparuk are too low. There will be no effect on production with an ELF change.**

INDUSTRY: When you increase the tax burden, the economics of projects get worse. At this point in the fields' lives and with low prices, many new projects are at the margin. These projects could go away with higher taxes alone. Additionally, there is less money to reinvest. Profits over the last three years are not high to begin with.

The industry must now guess if this is the first in a wave of higher oil taxes to support out-of-control state spending.

Over the next five years, BP plans to to invest $2.0 to $2.5 billion in North Slope development. That's both to develop and explore, because there are still good things to go after, and to develop the reserves we have remaining.

If we can repeat our past experience, investing that $2.0 or $2.5 billion will allow for an additional 750 million barrels of Alaska oil production.

That spending plan would be reassessed with an ELF change.

As reported in the Anchorage Daily News on March 15 (page A8) in a statement attributed to Paul Liebman, an oil analyst for First Boston Corp.,

> "To the extent that you're always changing the rules of the game, it just affects one's ability to plan in the future and throws a monkey wrench into projects that may be borderline. And, let's face it, there are a lot of projects in Alaska that are borderline at today's prices."

STATE: **Without the money, the State will lose thousands of workers. An ELF change will not affect industry employment.**

INDUSTRY: Strong state economies and strong national economies are powered by private enterprise, not excessive government spending. The proposed ELF change is an attempt to perpetuate Alaska's dependence on government spending at a rate 4-1/2 times the average for other states. In the short term, there may be more state workers just as there were in the boom years of the early 80's. In the medium term, it will become apparent that state spending cannot be maintained no matter what the oil industry is required to contribute. The dislocation that follows will be far more severe than if the money was left in the private sector now.

An ELF change will hurt projects like Hurl State which will add 37 million barrels to Prudhoe recovery. Hurl State will add 300 Alaskan construction jobs over a two year period. Some $12 million of modules will be built in Fairbanks.

STATE: **There is a technical problem with the ELF which gives an unintended windfall for drilling unnecessary wells.**

INDUSTRY: The industry has not drilled unnecessary wells to gain an ELF benefit. Hundreds of wells were drilled at Prudhoe Bay between 1981 and 1987 which had no effect on the ELF in that period because the Prudhoe rate was a constant 15 percent. Extra wells are drilled to increase or sustain production.

STATE: **The 1981 oil tax legislation was supposed to be almost revenue-neutral. Instead, the State has lost a billion dollars in FY 82 - FY 87.**

INDUSTRY: First, the correct figure is $670 million, according to the Department of Revenue's presentation to the House Resources Committee in February of this year.

The billion-dollar figure is based on the assumption that there would not have been a deduction for the federal Windfall Profit Tax under the state separate-accounting income tax if separate accounting had not been repealed in 1981. In fact, however, the legal advise the State received in 1981 said that there would have to be a deduction for WPT or else the chance of losing the lawsuit over separate accounting would be materially increased. Since the State wanted to win that lawsuit, there would have been a WPT deduction at least until the U.S. Supreme Court decided the case in 1985. Since oil prices declined from 1981 to 1985 - even before their collapse in 1986 - the impact of the WPT deduction would have already occurred before it could have been repealed after the Supreme Court's decision.

Second, the Legislature was advised by industry that the 1981 legislature would produce about 94 percent of the revenue that would be collected without that legislation, assuming that separate-accounting was ultimately upheld. In fact, during FY 82 - FY 87 the State has collected 93.2 percent of what it would have collected under the prior law, according to the same Department of Revenue presentation to House Resources last February.

STATE: **Governor Hammond now says that he expected a change after the ELF kicked back in for Prudhoe Bay.**

INDUSTRY: When Governor Hammond signed the 1981 legislation, it was recognized that there would be a drop in the production tax on Prudhoe Bay with the ELF stopped being "rounded" to one (1.0). This was going to happen in either of two possible ways. One would be when Prudhoe Bay reached its tenth anniversary in June 1987, when the rounding rule would expire for it. If this happened, the expected effect was about a 20 percent drop in production tax from that field (other fields would be unaffected). The other way the rounding could stop would be if, prior to June 1987, the computed value of the ELF for Prudhoe fell below 0.7 and would no longer be rounded upward to one. In this case the drop would be over 30 percent.

Recognizing that one or the other of these events was going to happen, Governor Hammond noted that if the revenue consequences for the State would be too great, he had full confidence in the ability of future legislatures to deal with it.

In fact, the State's share has continued to be above the minimum "fair" level of 30 percent since 1987, when the 10 years ran out for Prudhoe Bay. It is nearly half of the production revenue after operating costs. Even factoring in pipeline profits (a strange thing to consider, given that the ELF relates to a <u>production</u> tax and not a pipeline tax), the State's share is 35 percent this year.

Given that the State is still receiving its fair share, there is no need to change the ELF on the basis of what Governor Hammond said in 1981.

STATE: **The proposed ELF changes will accelerate the startup of marginal fields.**

INDUSTRY: The State has brought forward no producers at any field who have indicated that the proposed changes will accelerate or make possible the opening of any small fields.

The ELF automatically takes care of fields as they become marginal, because it starts with the percentage of production that is needed to cover the operating costs. If this "cost percentage" is high (as it would be when the field is getting marginal), the remaining percentage of the production representing potential profit is small. The ELF is based directly on this "profit percentage," so a small "profit percentage" means the ELF is small. A small ELF means a low tax rate.

Milne Point, for example, paid no production tax in the period prior to its shutting in. BP experience suggests that small field development is dependent on factors unrelated to production tax, e.g. at both Endicott and Niakuk, permitting and the use of causeways is of more direct significance than the production tax. Similarly, it would seem that the effective 18% royalty at Milne Point is the more proximate cause of Milne Point's difficulties and not a 3% or 4% production tax rate which will continue to drop under current law.

ILLUSTRATION OF HOW "ELF" WORKS

Explanation. The present oil ELF formula has two basic parts -- a base and an exponent, which is the power to which the base is raised. For example, (0.9)^2 means 0.9 is the base, and 2 is the exponent. 0.9 raised to the second power means 0.9 times 0.9, which equals 0.81. (The statute uses "exp" instead of "0" to indicate an exponent.)

For the ELF, the base is always less than one and as small as zero. The exponent is usually 460/300, or 1.533333. Because this exponent is larger than one, when it is applied to the ELF base number, the result is a number smaller than the base number.

This property of the exponent was illustrated above, when we saw that 0.9 to the second power is 0.81. Raising 0.9 to the power of 1.533333 equals 0.85082. Note that this is not as small a number as we got when we raised 0.9 to the second power. This shows another aspect about the exponent: the larger the exponent is, the smaller the result is when a particular ELF base number is raised to that exponent. Conversely, the smaller the exponent is, the larger the result is. When the exponent drops below one, the result will actually be larger than the original ELF base number. This latter property of the exponent becomes important only when the presumption is rebutted about 300 B/D per well being the break-even production rate.

The ELF base answers the question, what percentage of current production is deemed to represent profit. It does this by asking what fraction of the production is needed to cover the most fundamental operating costs. Once this fraction is determined, all the rest of the production is deemed to represent profit.

The amount of production needed to cover the most fundamental operating costs is called the "production rate at the economic limit," or "PEL" as it is called in the statute. For simplicity, let's call PEL the "break-even rate." It is presumed that the break-even rate is 300 barrels a day per well. The fraction of current production needed to cover these fundamental operating costs is simply the break-even rate divided by the current rate of production. Subtracting this fraction from one gives us the fraction of the production that is deemed to represent profit.Thus, the base of the ELF is --

$$1 - \frac{\text{break-even rate}}{\text{current production rate}}$$

or, as the statute expresses it, [1-(PEL/TP)]. PEL is the break--even rate, and TP is the current production rate.

When the presumption is not rebutted, the break-even rate equals 300 times the number of "well days" during any given month (the tax is computed and paid on a monthly basis). The number of well days is simply the number of hours that the wells were in production that month, divided by 24.

The ELF exponent is 460 times well days, divided by PEL. When the presumption for PEL is not rebutted, PEL equals 300 times well days. Thus, well days is a factor in both the numerator and the denominator of the exponent, and it cancels itself out. This simplifies the exponent to 460/300, or 1.533333.

Example 1. Unrebutted Presumption.

Suppose the presumption of 300 B/D per well has not been rebutted for a field that produces an average of 1.2 million B/D from 120 wells that all operated continuously during a 30-day month. The number of well days equals 120 wells times 30 days each, or 3600.

The ELF base starts with the ratio of the break-even rate to the current rate of production, and then subtracts that from one to come up with the fraction of current production that is deemed to represent profit. In this example, the break-even rate is 300 barrels a day times 3600 wells days in the month, or 1,080,000 barrel a month. Current production during the month is 1,200,000 barrels a day times 30 days, or 36,000,000 barrels. The ratio of the break-even rate (PEL) to the current rate (TP) is 1,080,000 divided by 36,000,000 -- or 0.030000. Subtracting this fraction from one gives us the fraction of production deemed to represent profit, or 0.970000. This is the base number for the ELF.

The ELF exponent is 460 times well days, divided by PEL. Since the presumption is not rebutted, PEL equals 300 times well days. Thus the exponent is simply the fraction

$$\frac{460 \times \text{Well Days}}{300 \times \text{Well Days}}$$

As you can see, the well days cancel each other out, leaving just 460/300, or 1.533333. The final ELF equals the base of 0.970000, raised to an exponent of 1.533333. This equals 0.954370.

Example 2. Rebutted Presumption.

Suppose everything is the same as in Example 1 except that the presumed break-even rate of 300 B/D per well has been rebutted and, instead, it has been shown that the field's actual break--even rate is 3,600,000 barrels per month (an average of 1,000 B/D per well).

The ratio of the break-even rate to the current production rate is now 3,600,000 barrels a month divided by actual production of 36,000,000 during the month, or 0.100000. Subtracting this fraction from one gives the fraction of the production deemed to be profit, or 0.900000. This is the new ELF base.

The ELF exponent also changes. Now it is 460 times well days, divided by the new break-even rate of 3,600,000 barrels a month. Since there are 3,600 well days in the month, the exponent equals 460 times 3,600, divided by 3,600,000 -- or 0.460000. Notice that the new exponent is less than one. This means that the result of applying the exponent will be something larger than the base of 0.900000 that it is applied to. In fact, the result of raising the new base of 0.900000 to the new exponent of 0.460000 is 0.952690.

This new ELF is almost the same as the 0.954370 that we got when the presumption was not rebutted -- in fact the new ELF is smaller than the first one by only 0.001680. In other words the tax will still be over 99% of what it would have been if the presumption had not been rebutted. This illustrates why the exponent was put into the formula in 1977. It was there to prevent the ELF from getting small as the result of rebutting the presumption while a large field like Prudhoe Bay was still in the early stages of development. True, rebutting the presumption would decrease the fraction of production that is deemed to represent profit, but this would be partially offset by the reduction in the size of the exponent. As this example shows, the two effects tended to offset each other almost exactly.

ALASKA'S FAIR SHARE

From 1981 through June 1987, the State's share was always more that the 30 percent fair share level. This is based on studies by the Department of Revenue.

Since June 1987, when the ELF "rounding" rule expired for Prudhoe Bay, the State's share has still been above 30 percent. Based on the present official price forecast of $7.36 for FY 89, the State is currently receiving almost half (49%) of the wellhead value of the oil after lifting costs and depreciation are taken out. The industry's share is 34 percent.

Over the last 3 years - for every $1 BP Exploration has earned after tax, it paid the State of Alaska $1.40.

BP Exploration (Alaska) Inc.	1986	1987	1988	AVG
After Tax Income	$140	$909	$560	$536
Payments to State	$604	$897	$751	$750

The current contention by OMB that the number is 29 percent is based on $18 oil. That price is $5.11 higher per barrel than FY 1990 mid-price forecast in October. With this price, state revenues would jump by about $700 million in FY 90. Presumably, the extra $700 million will more that offset the extra $100 million for the proposed ELF change.

Without more detail, it is impossible to check the OMB figures, although there probably is pipeline income included. Pipeline income should be excluded because severance tax is a tax on production, not transportation. Also, the income earned on the pipeline is dictated by the FERC settlement agreement which the State of Alaska signed along with members of the industry.

ECONOMIC LIMIT FACTOR

G.N. Nelson Testimony

Madam chairman and members of the committee:

For the record, my name is George N. Nelson, and I am president of BP Exploration (Alaska) Inc.

In 1986, you knew us as Sohio Alaska Petroleum Company.

In 1987 and 1988, you knew as Standard Alaska Production Company.

And now in 1989, we are the same company with a new name. Now we're known as BP Exploration and I hope this will be the last name change, as I am sure you will agree. This is not what we think of as stability.

With me today is Tom Williams. Most of you already know him. I consider Tom to be the most knowledgeable person in the state on the subject of the ELF; he fathered it when he was Director of Petroleum Revenue.

You may be wondering why I'm here testifying when he knows more about the history of ELF and the formula. It's because this bill is about producing oil, and that's been my job for the past 30 years.

I started in the oil business in Venezuela in 1955. Back then, Venezuela was viewed a lot like Saudi Arabia is today -- its reserves seemed unlimited. But then a funny thing happened in 1957. The government increased taxes on the oil business retroactively to the tune of $380 million. And there hasn't been another major oil field discovery since then.

I, like most others, moved on shortly after Venezuela's tax policy changed. I went to Libya, where I stayed from 1967 through 1975. Libya also has taken a high-tax, high-government-control approach. As a result, Libya's production hasn't met its potential, either.

Since 1975, I've worked on the Prudhoe Bay field. Our company has a 50% interest in Prudhoe, a 38% interest in Kuparuk, a 56% interest in Endicott and a 20% interest in Lisburne.

I mention this background because I think we can learn from the past. But we can't *live* in the past, and it appears to me after looking over the testimony in the House version of the most recent ELF bill that there's a dangerous emphasis on the past with no look to the future. Tom can answer your questions about what happened with ELF between 1977 and 1981, but I want to talk about the future.

How important are giant oil fields like Prudhoe Bay, and how much tax and royalty should they pay? Without Prudhoe, there would have been no $10 billion investment in the Trans Alaska Pipeline. There would be no Kuparuk. No Endicott. No Lisburne.

Without a large, commercial field in ANWR, there will be no pipeline from ANWR to TAPS. Without the potential for a large commercial find in ANWR, there would be no incentive to spend hundreds of millions of dollars to explore there.

Over the next decade, the vast majority of the new oil reserves on the North Slope should come from Prudhoe Bay and Kuparuk. *Should* come from from Prudhoe Bay and Kuparuk. But it will only happen if there's a commercial incentive to fully develop these two giant oil fields.

Senate Bill 97 would accomplish exactly the opposite. We would pay a lower tax rate on Prudhoe production of 1.4 million barrels a day than on 1.5 million barrels a day. The bill is written to reward *less* production from large and small fields alike. The message: Don't invest money to boost recovery. Lower production will be rewarded with lower tax rates.

Is this really what you intended? I don't think so.

Prudhoe and Kuparuk have been characterized as extremely profitable oil fields that can -- and should -- pay as much tax now as they did when prices were

twice what they are now. During the first half of the '80s, they *were* highly profitable. *And Alaska shared fully in that profit.* Between 1980 and 1986, the state collected nearly $25 *billion* in taxes and royalties. That's more than $7,000 per resident per year. Put another way, an Alaskan family of four had some *$200,000* in taxes and royalties paid on their behalf by the oil industry during this period.

But the heyday is over, and I, for one, don't think the state *or* the industry will see times like those again, at least not in this century.

Since 1986, our North Slope operations have been far less profitable. Based on our own experience, the oil industry's return on North Slope investment between 1986 and 1988 averaged about 10% a year. Compare that to the Alaska Permanent Fund, which, pursuing a conservative investment policy of avoiding risks, has generated a 12% average annual return over the same period.

During this three-year period, we've reported some $*540* million a year in after-tax profits from North Slope production. During the same period, we paid the State of Alaska and its municipalities some $*750* million a year in taxes and royalties on North Slope production. During the same period, we've reinvested 80% of our production profits in North Slope exploration and development -- an average of more than $430 million a year.

When the state's oil and gas tax legislation was last overhauled in 1981, there was a consensus between the legislative leadership and the administration that the state's "fair share" of the oil wealth should never fall below 30%. This corresponded with roughly a third for the state, a third for the industry and a third for the federal government.

According to studies by the Alaska Department of Revenue, the state's share was always more than 30% between 1981 and June of 1987. We know, and administration statements confirm, that the state share is still above 30%.

Based on the state's current official price forecast of $7.36 (wellhead value) for FY'89, the state is receiving almost *half* -- 49% -- of the wellhead value of oil after lifting costs and depreciation are taken out. The industry's share is roughly a third -- 34%. Even using the administration's numbers, which are based on a value at Valdez and include pipeline tariffs, the state's share is 36%.

Plenty of things besides oil prices have a significant impact on the profitability of Prudhoe and Kuparuk. Two of the most important are costs and the level of production.

Prudhoe has been producing oil for nearly 12 years now, and Kuparuk's been producing for more than seven. As you know, the North Slope has one of the

harshest climates in the world. Because maintenance costs were higher than anticipated, our expenses surpassed our budget by some $40 million last year alone. Now that our Prudhoe Bay facilities are operating at capacity, we can no longer make up for production lost due to maintenance, weather conditions or complications with tanker shipments. That means we're spreading higher costs over fewer barrels. Costs will continue to rise, and production will continue to decline.

So what exactly does this have to do with ELF? ELF takes into account the fact that oil production doesn't become marginal overnight. It's a gradual process, and that's how the ELF responds.

Prudhoe Bay currently pays about a 12% production tax. That's a very high rate -- far higher than the 4.9% rate in Texas and 7.1% in Oklahoma, but it's 3% lower than it was. Prudhoe was subject to the 10-year rounding rule until June of 1987. ELF links the payment of taxes to the ability to pay them, and that's good tax policy.

The ELF also contains an incentive to drill new wells and to maximize recovery from existing ones. This incentive will play a key role in slowing the decline in production at Prudhoe Bay and Kuparuk.

It's also creating private-sector jobs for Alaskans and millions of dollars in revenues for Alaskan contractors. Consider the example of our Hurl State development -- a small, marginal development within the huge Prudhoe Bay field.

Hurl State represents an investment of some $80 million, and it will boost recovery at Prudhoe by 37 million barrels. That's 37 million barrels more for the state to tax and collect royalties.

Just as important, it means jobs for Alaskans. In all, Hurl State will create some 300 construction jobs over a two-year period. And we've already demonstrated our commitment to use Alaskan contractors to perform the work. We recently awarded some $12 million in contracts to Alaskan firms to perform a portion of the work on Hurl State.

Union *and* non-union firms.

Anchorage *and* Fairbanks.

And there's more work to come -- drilling, installation and other projects.

We've also recently awarded a $5 million contract to Doyon Drilling, a Native corporation joint venture, to design, build and operate a workover rig at Prudhoe Bay. Workover rigs are used to perform remedial work on older wells to increase recovery. Native firms play an important role in our development activities and in our day-to-day operations -- from catering to drilling, from materials handling to maintenance.

Senate Bill 97 would discourage projects like Hurl State and workovers. It encourages us not to drill. It encourages us not to maximize production. Under certain circumstances, adding production for new wells would increase taxes on all other production. Again, I do not believe that was your intention.

Over in the House, a lot of debate has centered on what the bill would do for small, marginal fields. Smaller North Slope fields should not be ignored, but there is no reason incentives for small fields have to be linked to major tax increases on large fields.

Our experience with Niakuk and Endicott -- two fields that would qualify as "small" and "marginal" under terms of Senate Bill 97 -- has been that permitting can be the biggest hurdle to development.

And I can't overemphasize the fact that the current ELF provides adequate relief from the high normal rate for small fields like Milne Point. Because of the current ELF, Milne Point paid no production tax for several months prior to its shutdown. NO production tax. I can't think of a bigger production tax incentive than paying no taxes at all.

What Milne Point did continue to pay was an effective royalty in excess of 18%. Senate Bill 97 doesn't provide any royalty relief.

Changes proposed in the ELF are not really designed to encourage development and production at small fields. They're intended to raise revenues to support state government spending.

And why does state government spending require so much support in Alaska? For one thing, the number of state employees is growing -- by 1,312 between November 1987 and November 1988, according to the administration's own numbers. And the state budget continues to grow.

Changing the ELF will harm the industry, and it will harm the state. It could force the industry to defer expenditures and investments. It would send a clear message to all potential private investors that this state is determined to tax at any rate necessary to maintain spending at 4-1/2 times the national per-capita average.

We currently plan to spend $2 billion to $2.5 billion on North Slope development over the next five years. This five-year spending plan is expected to add 750 million barrels for BP alone to produce. And twice as much for the state to tax and collect royalty.

This committee, I'm sure, understands that most of our projects are close to the margin already. Cost increases could force us to forego some of them -- such as Hurl State.

Changing the ELF will also reinforce the industry's fears that every time the State of Alaska has a budget problem, we're going to get the bill for it.

$30 oil is a thing of the past. It ended years ago. It's 1989 now, and we've got lower prices and higher costs. Soon we'll have less production as well.

But we've also got something else: a broader and stronger support industry, as our current minimodule fabrication and pipe insulation contract work in Fairbanks attests to.

There are many factors influence our decisions on whether to go forward with development projects.

We can't control the price of oil.

We can't control inflation.

We can't stop facilities from aging, and we can't stop reservoirs from declining.

But we *can* try to convince you not to increase our costs by imposing a new tax burden by changing the ELF formula, and that's why we're here. The ELF encourages development -- the kind that helps Alaska build a strong private sector to fuel its future.

BP EXPLORATION

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TESTIMONY
OF
BP EXPLORATION
ON
HOUSE BILL NO. 118

(February 11, 1989)

Mr. Chairman, Members of the Committee: Good afternoon. My name is Thomas K. Williams, and I am here to testify on behalf of BP Exploration (formerly known as Standard Alaska Production Company) and its parent, BP America, regarding the changes to the Economic Limit Factor (ELF) proposed in House Bill No. 118. We believe the proposed changes are unnecessary, ill-advised, unfair and ill-conceived, and should not be adopted.

Unnecessary Changes. The changes are unnecessary because the present ELF formula is working perfectly well and as intended. Without an ELF, the production tax is a regressive tax. That is, the tax is the same regardless of how easily a field can afford to pay it. The ELF makes the tax progressive by assessing more profitable fields at a higher rate of tax, while allowing a lower tax rate for less profitable ones. Every field during its life makes a transition from a profitable phase to an increasingly less profitable one, until there eventually is no profit left at all and production ceases.

The present ELF formula reflects this transition as and when it occurs. It does so by asking what fraction of a field's current production is needed to cover the direct costs of getting that production out of the ground. When the fraction is small,

it means the field has a large operating margin that can be tapped for higher taxes. When the fraction is close to one, it means almost all the production is needed to cover costs, and the field cannot afford to pay a lot of tax. The ELF has been the key that has allowed Alaska to impose a tax with the highest rate in the nation (15%), without suffering any loss of production or development as the result of doing so.

The present ELF works perfectly fine for marginal fields. Milne Point is often cited as an example where the present ELF failed to work. The fact is, the ELF had reduced the tax rate to zero for Milne Point during the last half of the time it was in production. That is the ultimate in tax relief, and the proposed ELF formula in HB 118 cannot and will not provide any further relief for Milne Point than that.

Ill-advised Changes. The proposed changes to the ELF formula in HB 118 are ill-advised because the ELF would no longer depend on a field's relative profitability in setting the actual rate of tax. The changes being proposed appear to be intended to lower tax rates for fields with less than 150,000 barrels a day of production, while increasing them for fields with more.

This would place emphasis on a wholly inappropriate factor, field size. A field's size has, at best, only a loose relationship with how profitable it is and how much tax it can reasonably afford to pay. For example, in terms of dollars returned for each dollar invested, the most profitable field in Alaska's history is the McArthur River field, which never reached

the 150,000 barrel-a-day level. Yet this field would have been given tax relief as a "marginal" field under HB 118, even at its heyday.

The proposed changes are also ill-advised because the State stands to gain more from additional investment and development of Prudhoe Bay and Kuparuk than it will from any of the "marginal" fields on the North slope. The Eileen (West End) Project at Prudhoe Bay, for instance, will add over 100,000,000 barrels of new reserves. This single project is larger than either Milne Point or Niakuk. Yet the proposed new ELF formula would make it even more difficult to justify economically the investment in these large but increasingly marginal projects at Prudhoe Bay.

Testimony yesterday by the Cowper Administration endorsing changes to the ELF formula suggested that there are marginal fields just waiting for the ELF to be changed and then they will start producing. You were told, for example, that HB 118 could let Niakuk start up four years earlier. Well, you have been told wrong. What is holding Niakuk up is a permit for the causeway that it needs. And Milne Point already had a tax rate of zero under the present ELF, so I don't see how HB 118 could make a real difference there. The fact is, there are no commitments to develop any other new fields, no announced plans, not even any serious discussions. No one is saying that they will start up a new marginal field if you change the ELF formula for them. So don't let yourselves be misled into thinking there is a lot of marginal production to be gained by changing the ELF.

What you are hearing, and what you undoubtedly will continue to hear, are warnings about what changing the ELF will mean for marginal projects in the large fields. Such warnings, cautions,

caveats, or whatever you want to call them, are NOT intended to be threats. The industry is not going to pick up its marbles and go home if you change the ELF. But changing it will make some projects too expensive for us to afford. HB 118 will adversely affect the economics for developing the periphery of the two large fields and for continued in-fill drilling on closer well spacing to maximize recoverable reserves and keeps production as high as possible.

UNFAIR CHANGES. The proposed changes are unfair in at least three fundamental respects. First, fields in similar economic situations would be taxed at very dissimilar rates. For example, when Prudhoe Bay is averaging 500 barrels a day per well, its tax rate under this formula would still be approximately 11.95 percent, while Lisburne's rate at 500 barrels a day per well would be nearly a thousand times smaller -- only 0.016 of one percent. I have attached a worksheet to my written testimony, which shows how these numbers have been calculated.

Second, HB 118 is unfair because the oil industry is already being disproportionately taxed relative to other industries in Alaska. In the January 1989 edition of Alaska Business Monthly, economist Andrew Safir writes that oil and gas contributed 33.3 percent of Alaska's "gross state product" in 1986, the latest year for which figures are available. But although petroleum represents only one third of the economy, it accounts for 90 percent of

the money the State of Alaska collects each year. It is unfair to demand more taxes from the oil industry when all other industries enjoy such smaller burdens.

Third, the proposed changes to the ELF are unfair because the State is already receiving a fair share (or more) from North Slope oil production. In 1981 there was a political consensus that the wealth of the petroleum resource should be shared roughly equally among the three interests sharing in it -- the State of Alaska, the oil industry and the IRS. As far as Alaska was concerned, it would be content that it was receiving its fair share as long as that share did not go below 30 percent. Figures published by the Department of Revenue in 1985 and 1986 show that the State has stayed above this 30 percent minimum for each fiscal year since 1981. In fact, the 1986 analysis, which was published by the Cowper Administration before the ELF debate flared up, shows that the State's share of net production and pipeline revenues this fiscal year would be 69.4 percent at $7.00 wellhead prices, and 55.4 percent at $9.00 wellhead prices. The latest revenue forecast, from last October, predicts an average wellhead price this fiscal year of $7.36 (mid case), which means the State is likely to be closer to the 69% figure instead of the 55% one. In the future, as operating costs continue to go up and production starts to go down, the trend will be for the State's share of the net revenue to increase rather than decrease.

Ill-conceived Changes. If the intent of HB 118 is to have the same tax rate for a 150,000 barrel-a-day field as under

the present tax, with lowered rates for smaller fields and increased rates for larger ones, then the formula in the bill is wrong. The math simply does not work. This is because the bill takes the exponents in the wrong order.

The sequence in which exponents are taken makes a big difference. For example, take

$$4^{3^2}.$$

This may be easier to think about (and certainly easier to type!) if we use a caret ("^") to indicate that an expression is an exponent. The expression above would then look like this: 4^3^2.

Without any parentheses to indicate a different order, the correct sequence in a compound exponent is to start at the top and work down or, when using carets to indicate exponents, to start at the right and work left. Thus, we first raise three to the second power: three squared is nine.

$$\begin{aligned} 4\text{^}(3\text{^}2) &= 4\text{^}(3 \times 3) \\ &= 4\text{^}(9) \end{aligned}$$

Then we raise four to the ninth power. Four times itself nine times is 262,144.

$$\begin{aligned} 4\text{^}9 &= 4 \times 4 \times 4 \times 4 \times 4 \times 4 \times 4 \times 4 \times 4 \\ &= 262{,}144 \end{aligned}$$

If we went the other way, starting with four and working our way to two, then four cubed is 64, and 64 squared is 4,096.

$$(4^3)^2 = (4 \times 4 \times 4)^2$$
$$= (64)^2$$
$$= 64 \times 64$$
$$= 4,096$$

As you can see, this produces a very different result from the first. The order in which compound exponents are applied is crucial in determining the outcome.

The formula in HB 118 takes the exponents in the wrong sequence from what seems to be intended. In the present ELF formula there are two components: a "base" and an exponent. If we use "A" to represent the base and "B" to represent the exponent, the present formula is A^B. HB 118 introduces a new component, a second exponent, into the formula between "A" and "B;" "A" and "B" are the same in the proposed formula as they are in the present one, so the difference between the two formulas is this new, second exponent. If we call this new exponent "C," then the new formula is A^C^B. But is this (A^C)^B or A^(C^B)? As HB 118 is written, the formula is A^(C^B).

"C" is defined in the bill to be [150,000/(TP/WD)]. In other words, "C" equals 150,000 divided by the average daily production from the field during the tax period. It is plain that "C" is intended to equal 1.0 for a 150,000 barrel-a-day field, because then "C" equals 150,000 divided by 150,000. But if the number one is raised to any power, the result is still one. For a 150,000 barrel-a-day field, A^(C^B) will be A^(1^B), or A^(1). Any number raised to the first power is the same

number, so A^(1) is the same as "A." Hence the ELF for a 150,000 barrel-a-day field will be "A" under HB 118, instead of A^B. The ELF will not be the same, and in fact the tax will be higher for a 150,000 barrel-a-day field under HB 118 than it is under the present law (assuming in the present law the 300 B/D/well presumption for the field has not been rebutted and shown to be 460 B/D/well or more).

In conclusion, then, the proposed changes to the ELF formula are unnecessary because the present formula is not broken and does not need to be fixed. The proposed changes are ill-advised because field size is not a reliable indicator of a field's economic health and ability to withstand a high rate of tax. They are also ill-advised because they over-emphasize the importance of so-called "marginal" fields at the expense of marginal projects in the large fields: marginal projects in large fields can have greater overall benefits for Alaska and Alaskans than the development of small fields. The proposed changes to the ELF are unfair, first, because of the wildly different treatment that will occur between comparably profitable fields; second, because of the disparity between the present level of taxation on the oil industry and the burden on any other resource industry; and third, because the State is already receiving more than a fair share of the value of the resource. The proposed changes to the ELF are ill-conceived because the formula in the bill is mathematically deficient and fails to achieve the

apparent objective of keeping the tax rate the same for fields producing 150,000 barrels a day.

Thank you for this opportunity to testify to you today. I would be pleased to answer any questions the Committee may have.

Prudhoe Bay

Average Production Rate per Well = 500 B/D
Number of Wells (projected) = 745
Fieldwide Production = 372,500 B/D

"A" = (1 - [PEL/TP])
= (1 - [(300*745)/372,500]
= 0.400000

"B" = [150,000/(TP/Days)]
= [150,000/372,500]
= 0.402685

"C" = [(460*WD)/PEL]
= [(460*WD)/(300*WD)]
= [460/300]
= 1.533333

Tax Rate = ELF * 15%
= [A^(B^C)] * 15%
= [0.400000^(0.402685^1.533333)] * 15%
= [0.400000^0.247902] * 15%
= [0.796801] * 15%
= 11.95202%

Lisburne

Average Production Rate per Well = 500 B/D
Number of Wells (projected) = 81
Fieldwide Production = 40,500 B/D

"A" = (1 - [PEL/TP])
= (1 - [(300*81)/40,500]
= 0.400000

"B" = [150,000/(TP/Days)]
= [150,000/40,500]
= 3.703704

"C" = [(460*WD)/PEL]
= [(460*WD)/(300*WD)]
= [460/300]
= 1.533333

Tax Rate = ELF * 15%
= [A^(B^C)] * 15%
= [0.400000^(3.703704^1.533333)] * 15%
= [0.400000^7.445755] * 15%
= [0.001089] * 15%
= 0.01634%