COMMITTEE REPORT

SENATE

FURTHER:

4/9/86

Date 4/22/86

Mr. President

The Committee on FINANCE considered HB 559

approving the sale of Kuparuk River Unit royalty oil by the State of Alaska to Petro Star, Inc. and Chevron U.S.A., Inc.; efd.

and (a majority of the committee) (the committee) reports it back with the following recommendations:

[✓] do pass

[ ] do pass with attached amendment(s)

[ ] replace with/or adopt CS for

[ ] new title

[ ] same title and recommends

[ ] and attached a "LETTER OF INTENT" [ ] NEW FISCAL NOTE

(1,151.1) DNR/Oil&Gas

0 DNR/Mgmt

5 DOR

[ ] reports it back without recommendation

[ ] recommends referral to ______ Committee

MEMBERS SIGNING DO PASS

Rick Halford

Carl Frisk

MEMBERS HAVING OTHER RECOMMENDATIONS

No Rec

do not alter for other programs.

Fischer - No rec.

Co - Chairman

do pass

Chairman recommendation

STATE OF ALASKA 1986 LEGISLATIVE SESSION
FISCAL NOTE

Revision Date : 2-26-86

REQUEST Page 1 of 2

Bill/Resolution No. : HB 559
Title : Kuparuk Royalty Oil Sale to Petrostar/Chevron

Sponsor : Governor
Requestor : Oil & Gas
Date of Request : 02-25-86

FISCAL DETAIL

Agency Affected : Natural Resources
BRU : Petroleum Management

Components :

EXPENDITURES/REVENUES : (Thousands of Dollars)

OPERATING	FY 86	FY 87	FY 88	FY 89	FY 90	FY 91
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0	0	0	0	0	0
CAPITAL	0	0	0	0	0	0
REVENUE	0	1,151.1	1,067.4	1,067.4	907.3	771.5

FUNDING : (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL	0	0	0	0	0	0

POSITIONS :

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS : Attach a separate page if necessary

Note: Revenue computations by calendar year instead of fiscal year.

See attached

Prepared by : Jim Eason
Division : Oil & Gas
Phone : 762-4246
Date : 2-26-86

Approved by Commissioner : [signature] Deputy
Agency : Natural Resources
Date :

Distribution (by Agency preparing fiscal note) :
- Legislative Finance
- Legislative Sponsor.
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)

10/25/85

ANALYSIS
Fiscal Note HB 559 - Page 2 of 2

Approval of the proposed Petrostar/Chevron will result in the state's receipt of approximately $7.5 million in premium payments over the term of the contract. Approximately 16,756,670 barrels of oil will be delivered under the contract, with Chevron's respective share being 11,171,002 barrels, and Petrostar's share being 5,585,668 barrels. Chevron will pay a premium above the "in value" amount of $.50 per barrel, while Petrostar's premium will be $.35 per barrel for its net barrels. Chevron's share of this premium will total $5,585,501 over the life of the contract (contract ends September 30, 1996), and Petrostar's respective contribution will be $1,954,984. All amounts calculated are expressed in "nominal"dollars, and the analysis assumes contract deliveries commence December 1, 1986 and ends September 30, 1996.

Revenue Projects

Calendar Year

92	655.5
93	592.0
94	528.8
95	475.4
96	323.0
Total	7,539.4

C 2/10

4/8

STATE OF ALASKA 1986 LEGISLATIVE SESSION
FISCAL NOTE

Revision Date: 1-31-86

REQUEST HB 559 #1

Bill/Resolution No.: 377-094-86
Title: An act approving the sale of royalty oil to Petro Star

Sponsor: Governor
Requestor: Governor
Date of Request: 1/29/86

FISCAL DETAIL

Agency Affected: Natural Resources
BRU: Petroleum Management

Components: Petroleum Management

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 86	FY 87	FY 88	FY 89	FY 90	FY 91
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0	0	0	0	0	0
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL	0	0	0	0	0	0

POSITIONS:

FULL-TIME	0	0	0	0	0	0
PART-TIME						
TEMPORARY						

ANALYSIS: Attach a separate page if necessary

The contract will result in routine billing and accounting functions which can be absorbed in the existing operation.

Prepared by: Rod Mourant RAM Phone: 465-2424
Division: Management Date: 1-31-86

Approved by Commissioner: James D Smith, Deputy Date: 1/31/86
Agency: Natural Resources

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)

10/25/85

Natural Resources

STATE OF ALASKA 1986 LEGISLATIVE SESSION
FISCAL NOTE

Revision Date :

REQUEST HB 5?? [illegible]

Bill/Resolution No. :
Title : An Act approving the sale of royalty oil to Petro Star and Chevron U.S.A.
Sponsor : Rules Committee at the request
Requestor : of the Governor
Date of Request : 1/28/86

FISCAL DETAIL

Agency Affected : Revenue
BRU :
Components : operating

EXPENDITURES/REVENUES : (Thousands of Dollars)

OPERATING	FY 86	FY 87	FY 88	FY 89	FY 90	FY 91
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING		-0-	-0-	-0-	-0-	-0-
CAPITAL						
REVENUE						

FUNDING : (Thousands of Dollars)

	FY 86	FY 87	FY 88	FY 89	FY 90	FY 91
GENERAL FUND		-0-	-0-	-0-	-0-	-0-
FEDERAL FUNDS						
OTHER						
TOTAL		-0-	-0-	-0-	-0-	-0-

POSITIONS :

	FY 86	FY 87	FY 88	FY 89	FY 90	FY 91
FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS : Attach a separate page if necessary

Prepared by : Phone :
Division : Date :

Approved by Commissioner : [signature] Date : 1/28/86
Agency : Dept. of Revenue

Distribution (by Agency preparing fiscal note) :
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)

page ___ of ___

10/25/85

REVENUE

Introduced: 2/10/86
Referred: House Special Committee on
Oil & Gas, Resources and Finance

IN THE HOUSE

BY THE RULES COMMITTEE BY
REQUEST OF THE GOVERNOR

HOUSE BILL NO. 559

IN THE LEGISLATURE OF THE STATE OF ALASKA

FOURTEENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act approving the sale of Kuparuk River Unit royalty oil by the State of Alaska to Petro Star, Inc. and Chevron U.S.A., Inc.; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. The "Agreement for the Sale and Purchase of State Royalty Oil" between the State of Alaska and Petro Star, Inc. and Chevron U.S.A., Inc., dated December 9, 1985, is approved and ratified.

* Sec. 2. This Act takes effect immediately in accordance with AS 01.-10.070(c).

HB559

RECEIVED
DEC 10 1985
DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

AGREEMENT FOR THE SALE AND PURCHASE

OF

STATE ROYALTY OIL

PETRO STAR, INC.

CHEVRON U.S.A.

THE STATE OF ALASKA
Department of Natural Resources

December 9, 1985

TABLE OF CONTENTS

DOG 9-85
(PETRO STAR & CHEVRON/KUPARUK)
(Revised 11-85)
(DNR # 10-4017)

AGREEMENT FOR THE SALE AND PURCHASE OF ROYALTY OIL

THIS AGREEMENT, entered into as of December 9, 1985 by and between THE STATE OF ALASKA ("Seller") PETRO STAR, INC., an Alaska corporation, ("Purchaser Petro Star"), and CHEVRON U.S.A. INC., a Pennsylvania corporation, ("Purchaser Chevron").

ARTICLE I
DEFINITIONS

As used in this Agreement, the following terms shall have the following respective meanings:

1.1 "Commissioner" means the Commissioner of the Alaska Department of Natural Resources or her designee.

1.2 "Day" means a period of twenty-four (24) consecutive hours, beginning at 12:01 a.m., Alaska Standard Time.

1.3 "Leases" means the oil and gas leases which are subject to the terms of the Unit Agreement.

1.4 "Lessee" means any person owning a working interest in any of the Leases.

1.5 "Month" means the period beginning at 12:01 a.m., Alaska Standard Time, on the first day of the calendar month and ending at the same time on the first day of the next succeeding calendar month.

1.6 "Oil" or "crude oil" shall have the same meaning as the word "oil" under the Unit Agreement.

1.7 "Point of Delivery" shall have the meaning set out in Section 2.5.

1.8 "Purchaser" means either Petro Star, Inc., or Chevron U.S.A. Inc., or both, unless one particular Purchaser is designated.

1.9 "Prudhoe Bay Lessees" means the lessees of the oil and gas leases subject to the Prudhoe Bay Unit Agreement effective April 1, 1977, as amended from time to time.

1.10 "Prudhoe Bay Royalty Oil" means Royalty Oil received from the Prudhoe Bay Lessees.

1.11 "Royalty Oil" means the oil which Seller may take in kind (amount) as its royalty under the Leases whether or not Seller has elected to take or is taking that royalty in kind.

1.12 "Daily Royalty Oil" means the quantity of Royalty Oil produced by the Lessees each day.

1.13 "Settlement Agreement" means the Agreement for Settlement of Cleaning, Dehydration and Transporation Charges Applicable to Royalty Oil Taken From the Kuparuk River Unit, effective as of December 13, 1981, and attached to the Unit Agreement as Appendix I.

1.14 "TAPS" means the Trans Alaska Pipeline System.

1.15 "Unit Agreement" means the Kuparuk River Unit Agreement effective as of December 1, 1981, by and between Seller and the Lessees, as amended from time to time.

ARTICLE II
SALE OF ROYALTY OIL

2.1 Quantity. Seller agrees to sell to Purchaser Petro Star, and Purchaser Petro Star agrees to buy from Seller, that amount of oil equal to __________ % of the Daily Royalty Oil ("Maximum Quantity"). Seller agrees to sell to Purchaser Chevron, and Purchaser Chevron agrees to buy from Seller, that amount of oil equal to __________ % of the Daily Royalty Oil ("Maximum Quantity"). Promptly after the effective date of this Agreement, Seller will determine the actual percentages, which will be the percentages that on the date of initial nomination would result in a Maximum Quantity for Purchaser Petro Star that on the Date of First Delivery would approximate 2500 bpd and a Maximum Quantity for Purchaser Chevron that on the Date of First Delivery will approximate 4000 bpd. However, unless Purchaser Petro Star notifies Seller in writing within five (5) days after the effective date of this Agreement, Seller will initially nominate for Purchaser Petro Star the percentage that Seller estimates will on the Date of First Delivery approximate 2000 bpd.

Upon at least nine (9) months' written notice to Seller, Purchaser may increase or decrease the amount of Daily Royalty Oil to be tendered by Seller at the Point of Delivery, provided that the amount tendered by Seller under this Agreement shall not exceed the Maximum Quantity. If by November 1, 1987 Purchaser Petro Star has not begun to take the Maximum Quantity of oil, Seller, at its option and discretion, may permanently decrease the Purchaser Petro Star's Maximum Quantity to either (1) the greatest percentage of Daily Royalty Oil tendered by Seller to it before that time or, (2) the maximum amount of oil that can be processed at Purchaser Petro Star's refinery, located at North Pole, Alaska. Purchaser may permanently decrease its Maximum Quantity under this Agreement upon nine (9) months' written notice to Seller.

It is understood and agreed that the volume of Daily Royalty Oil available to Seller will vary and may be interrupted from time to time, and depends upon a variety of factors, including the rate of production from the Leases. Seller disclaims and Purchaser waives any representation, covenant or warranty, express or implied, as to the specific quantity, or the total or daily, monthly, average, or aggregate volume of Oil to be sold or tendered under this Agreement. Seller shall hold Purchaser harmless from all liens, encumbrances and valid adverse claims that may affect the Oil at the time the Oil is tendered to Purchaser.

If Seller stores Royalty Oil pursuant to the Kuparuk River Unit Emergency Storage Agreement dated December 15, 1981, and attached as Appendix II to the Unit Agreement, (the "Storage Agreement"), or otherwise, or if Seller recovers stored Royalty Oil, the quantity of Oil to be sold and purchased under this Agreement shall be calculated as if no Royalty Oil was stored or recovered.

2.2 Quality. The Oil sold shall be the same quality as the Royalty Oil delivered by the Lessees to Seller at the Point of Delivery. It is understood and agreed that the quality of the Oil sold may vary from time to time. Seller disclaims, and Purchaser waives, any guarantee, representation, or warranty, either express or implied, of the merchantability, fitness for use, or suitability for any particular use or purpose, or otherwise, of any of the Oil delivered under this Agreement or as to any specific, average or overall quality or characteristic of Oil to be sold or tendered under this Agreement.

2.3 Price of the Royalty Oil. The price payable by Purchaser Petro Star for Oil tendered under this Agreement ("Petro Star Purchase Price") shall be equal to the amount that Seller actually would receive from its Prudhoe Bay Lessees for that amount of Prudhoe Bay Royalty Oil taken at that time in money (in value), plus 35¢ per barrel and plus the Kuparuk Field Cost Allowance incurred by the Oil as determined under the Settlement Agreement, less the tariff charge for the Kuparuk Pipeline and less the applicable TAPS quality bank adjustment.

The price payable by Purchaser Chevron for Oil tendered under this Agreement ("Chevron Purchase Price") shall be equal to the amount that Seller actually would receive from its Prudhoe Bay Lessees for that amount of Prudhoe Bay Royalty Oil taken at that time in money (in value), plus 50¢ per barrel and plus the Kuparuk Field Cost Allowance incurred by the oil as determined under the Settlement Agreement, less the tariff charge for the Kuparuk Pipeline and less the applicable TAPS quality bank adjustment.

The in value component of each Purchase Price shall be determined by Seller based upon the reports submitted by the Prudhoe Bay Lessees for royalty purposes or, when those reports are unavailable, incomplete or inaccurate, upon information submitted by the Prudhoe Bay Lessees for production tax or other tax purposes as may be adjusted from time to time as provided in this Agreement. Purchaser shall be entitled only to review or request such material or information which is not confidential under state law or regulation.

The method, basis and amount of royalty due Seller when it takes its Prudhoe Bay Royalty Oil in value from its Prudhoe Bay Lessees is presently the subject of litigation in <u>State of Alaska, et al v. Amerada Hess Corp., et al.,</u> (Superior Court for the State of Alaska, First Judicial District at Juneau) ("<u>Amerada Hess</u>"). One of the issues involved is the proper method to be used by the Lessees in calculating the state's royalty when the royalty is payable in money (in value). Until there is a resolution of that dispute through judicial resolution or settlement, the Purchase Price will be based upon the calculation of an amount per barrel equal to the per barrel volume weighted average of the in value prices reported by the Prudhoe Bay Lessees to Seller for royalty purposes or, when the royalty reports are unavailable, incomplete, or inaccurate, upon information submitted by the Prudhoe Bay Lessees for production tax or other tax purposes, plus $0.35 per barrel for Purchaser Petro Star and $0.50 for Purchaser Chevron, and plus the Kuparuk Field Cost Allowance as determined under the Settlement Agreement, less the Kuparuk Pipeline tariff and less the applicable TAPS quality bank adjustment. Upon resolution of each of the various issues that are or will be involved in

Amerada Hess, adjustments will be made to previous payments in accordance with each resolution. However, Seller and Purchaser agree that any Amerada Hess adjustments in excess of $2.50 per barrel will not be made. This sum represents a negotiated ceiling, and is not any party's estimate of litigation results.

If additional amounts are owed by Purchaser to Seller or by Seller to Purchaser under a final judgement or settlement resolving all or part of the issues in Amerada Hess which separately specifies principal and interest, interest will be paid on the principal component of the additional amounts in the manner and at the interest rate or rates specified in the judgement or settlement resolving each issue. If no interest rate is specified in the judgement or settlement or if interest is expressly included within a lump sum amount in the judgement or settlement, an interest component will be presumed to already comprise a portion of the additional amounts, and no separate interest will be paid.

Purchaser Petro Star will not voluntarily intervene or otherwise participate in Amerada Hess unless Seller expressly consents to that participation in writing. A settlement of Amerada Hess will be binding upon Purchaser whether or not Purchaser agrees with or consents to the terms of that settlement.

If any applicable law of the United States of America or any rule or regulation promulgated by a federal agency will, in the judgment of Seller, operate to prohibit or prevent Seller from receiving the full amount due under the above provisions, Purchaser's obligation to pay the amount of the Purchase Price in excess of the amount permitted will be suspended or adjusted to the minimum extent required for Seller to comply with that law, rule or regulation.

2.4 Purchase Price Reopener. Seller and each Purchaser shall have the right to reopen this Agreement with respect to each Purchaser's own volume, as to purchase price only. At any time after Purchaser receives Oil for two (2) years from the Date of First Delivery (as defined in Section 2.10), Seller or Purchaser may exercise the right to reopen by giving to the other party one (1) month prior written notice. Upon issuance and receipt of a notice to reopen, that Purchaser and Seller will promptly commence good faith negotiations in an attempt to establish a new purchase price. In the event that a new purchase price is not agreed to by that Purchaser and Seller within three (3) months after giving the notice to reopen, that Purchaser or Seller may terminate that Purchaser's portion of this Agreement upon nine (9) months written notice to the other. The purchase price for Oil tendered during any period pending termination shall be the price in effect immediately prior to giving the notice of intent to reopen. If a new purchase price is agreed to by that Purchaser and Seller, the new purchase price shall become effective for Oil tendered in the month following the Agreement on the new purchase price. Not less than two (2) years after the conclusion of the purchase price reopener process described above, that Purchaser or Seller may reopen that Purchaser's portion of this Agreement, as to purchase price only, by giving notice of intent to exercise the right to reopen. At that time, the purchase price reopener process described above will again be applicable.

2.5 Point and Time of Delivery. Simultaneously with receipt of its Royalty Oil from its Lessees, Seller shall tender the Oil to Purchaser at the point at which Seller receives the Royalty Oil from its Lessees. That point as presently agreed to by Seller and its Lessees in Section 2.3 of the Settlement Agreement is the Central Production Facility Meter into the Kuparuk Pipeline.

2.6 Passage of Title and Risk of Loss. Title and risk of loss to the Oil sold under this Agreement shall pass from Seller to Purchaser for all purposes when Seller tenders the Oil at the Point of Delivery.

2.7 Purchaser's Responsibility. Purchaser shall be responsible for the O ! after passage of title. Purchaser will indemnify and hold Seller harmless from and against any and all claims, costs, damages (including reasonably foreseeable consequential damages), expenses or causes of action arising from or in connection with any transaction or event which relates to the crude oil after title has passed to Purchaser.

2.8 Transportation Arrangements. Purchaser shall make all necessary arrangements for transporting the Oil sold under this Agreement from the Point of Delivery, including satisfaction of line fill obligations and storage tank bottom requirements of the Kuparuk Pipeline and Trans Alaska Pipeline System, if any. If and as requested by Seller, and at the time or times requested by Seller, Purchaser shall submit specific information concerning the arrangements it has made for transportation of the Oil sold under this Agreement through and away from Kuparuk Pipeline and the Trans Alaska Pipeline System and for the resale or other disposal of the Oil. Such information may include the specific tenders of Oil made to the Kuparuk Pipeline and Trans Alaska Pipeline System and identification of tankers which will transport the Oil. In addition, Purchaser will provide Seller, if and as requested by Seller, with satisfactory evidence or reasonable assurances of the existence and continuing validity of adequate arrangements for the transportation or disposal of the Oil subject to this Agreement. Failure to provide information, evidence or assurances requested will, at Seller's election by notice to Purchaser, be a material default under this Agreement.

2.9 Absolute Obligations. The obligations of Purchaser to accept, pay for, and arrange for the transportation of the Oil tendered or sold under this Agreement are absolute and will not be excused or discharged by the operation of any disability of Purchaser, event of force majeure, impracticability of performance, change in conditions, or any other reason or cause.

2.10 Date of First Delivery. The Date of First Delivery will be on the first day of the first month seven (7) months after the effective date specified in Article VI, unless Seller, in its sole discretion at the request of both Purchasers, sets an earlier date.

2.11 In-State Processing. Purchaser Petro Star agrees that not less than 85% of the Royalty Oil sold under this Agreement, averaged on a quarterly basis, shall be processed through Purchaser Petro Star's refinery near North Pole, Alaska, except as provided below. "Process" means producing refined petroleum products from the crude oil in significant quantities, but which quantities may not be less than 20% of the volume of Royalty Oil run through Purchaser Petro Star's refinery pursuant to this Agreement.

Purchaser Petro Star's obligation to process Royalty Oil in-state may only be suspended or excused under (1) the provisions of Articles VIII and XI, or (2) during refinery maintenance.

Seller may, at its option, waive the in-state processing requirement in whole or in part, if Seller is satisfied that Purchaser Petro Star is using its best efforts to process the Royalty Oil sold under this Agreement at Purchaser Petro Star's refinery and that the waiver would not be contrary to the underlying intent of the other provisions of this Agreement.

2.12 Best Efforts. (1) Purchaser Petro Star agrees to use its "best efforts" to produce and market in Alaska an amount of refined petroleum products from its refinery near North Pole, Alaska not less in volume than 23% of the Royalty Oil sold under this Agreement. Those refined petroleum products shall be comprised of at least LAGO and Kerosene. After each three (3) months of deliveries under this Agreement, Purchaser Petro Star shall promptly provide to the Seller an affidavit certified by Purchaser Petro Star stating the quantity of refined petroleum products produced and marketed in the State of Alaska from in-state processing of the Daily Royalty Oil sold under this Agreement for that period.

A determination of "best efforts" under this Article shall include consideration of Purchaser Petro Star's capabilities and the surrounding business circumstances. Purchaser Petro Star's obligation to use its best efforts includes reasonable, diligent, and good faith efforts, but shall not require Purchaser Petro Star to produce and market refined petroleum products in Alaska at a loss. "Best efforts" would, however, require Purchaser Petro Star to produce and market products in Alaska even though Purchaser Petro Star could make a greater profit by another disposition of the Royalty Oil or the products refined from that oil.

2.13 Option to Purchase Return Oil. After Purchaser Petro Star processes Royalty Oil, there will remain a portion of Oil or Oil products which may be shipped through TAPS ("Return Oil"). Return Oil shipped through TAPS becomes intermingled with unprocessed crude oil so that when the Return Oil is picked up in Valdez it is identical to the common stream crude oil shipped through TAPS. A shipper of Return Oil presently is, and may continue to be, liable for the payment of a quality bank adjustment differential based upon the resulting degradation of TAPS common-stream crude ("quality bank adjustment").

The total daily volume of Royalty Oil sold under this Agreement approximates Purchaser Petro Star's daily refinery throughput. Purchaser Petro Star's daily Maximum Quantity approximates its maximum retained product and Purchaser Chevron's daily Maximum Quantity approximates what would otherwise be Purchaser Petro Star's return oil. Thus, under the arrangements contemplated under this Agreement, no return oil would exist upon which the state could retain an option. Should the arrangements contemplated under this Agreement cease to exist, Purchaser and Seller agree to negotiate in good faith towards agreement upon a market price option for Seller on whatever return oil or residual oil may exist under the new arrangements.

2.14 Arrangements between Purchasers. Purchaser Chevron and Purchaser Petro Star have entered into an arrangement under which Purchaser Petro Star will use as refinery charge Purchaser Chevron's volume of Royalty Oil under this Agreement. The arrangement includes the purchase of Royalty Oil taken by Purchaser Chevron under this Agreement by Purchaser Petro Star at TAPS Pump Station No. 1, and resale of the Royalty Oil to Purchaser Chevron at Valdez. A copy of the document which specifies the terms of the arrangement is attached as Exhibit A. Should the terms of the arrangement change materially so that Purchaser Petro Star is precluded from economically using Purchaser Chevron's volume as refinery charge, Seller shall have the right at the Commissioner's discretion to terminate this Agreement on nine (9) months notice.

Should Purchaser materially reduce its Maximum Quantity under Section 2.1 or terminate its portion of this Agreement under Section 2.4, or should termination occur due to an Event of Default under Article VII, either Seller or the other Purchaser may terminate the remaining portion of this Agreement by giving nine (9) months written notice, except as provided below. In this section a material reduction means a reduction of 50% or more from the original Maximum Quantity.

Upon termination of Purchaser Petro Star's portion of this Agreement for any reason or material reduction of Purchaser Petro Star's Maximum Quantity under Section 2.1, Seller shall exercise its right to terminate Purchaser Chevron's portion of this Agreement. However, if Purchaser Chevron agrees to process in its refinery at Nikiski, Alaska the Royalty Oil to be sold under this Agreement after that time, and if Purchaser Chevron successfully completes negotiations with the commissioner for an amendment to this Agreement which grants Seller a market price option on Purchaser Chevron's residual oil resulting from the processing of that oil, the Commissioner shall have the discretion to not terminate Purchaser Chevron's portion of this Agreement.

Upon termination of Purchaser Chevron's portion of this Agreement for any reason or material reduction of Purchaser Chevron's Maximum Quantity under Section 2.1, Purchaser Petro Star shall have the option to continue purchasing up to its Maximum Quantity, or to increase its Maximum Quantity to include all or part of the volume formerly purchased by Purchaser Chevron under this Agreement. Purchaser Petro Star shall exercise this option in writing within one month of the termination of Purchaser Chevron's portion of this Agreement. Purchaser Petro Star's option shall be conditioned on Purchaser Petro Star (1) agreeing for any increased quantity to pay the Purchase Price that Purchaser Chevron would pay under this Agreement, (2) agreeing to increase its Section 15.2 letter of credit to ninety (90) days for all volumes it would purchase under this Agreement, (3) agreeing to pay its Section 15.3 Amerada Hess escrow amount for all volumes it would purchase under this Agreement, (4) agreeing to increase its Section 2.11 and Section 2.12 in-state processing and best efforts obligations to include all volumes it would purchase under this Agreement, and (5) successfully completing negotiations with the Commissioner for an amendment to this Agreement which grants Seller a market price option on Purchaser Petro Star's return oil from all volumes it would purchase under this Agreement. The Commissioner shall have the discretion to accept other or additional security arrangements as part of Purchaser Petro Star's option as she, in her sole discretion, considers adequate to protect Seller. In accordance with Article XIX of this Agreement, the exercise of any option described in this section that would appreciably reduce the consideration received by Seller requires prior approval of the Alaska Legislature.

2.15. Performance Guaranty and Reservation Fee. If Purchaser does not take the Maximum Quantity on the Date of First Delivery, Purchaser shall pay to Seller, in addition to the Purchaser Price, an amount equal to 1.25% of the Purchase Price per barrel per day on the difference between the Maximum Quantity and the actual quantity tendered to and accepted by Purchaser ("Actual Quantity") for each day Purchaser does not take the Maximum Quantity on and after the Date of First Delivery. The payment of this fee shall end on the day that Purchaser accepts delivery of the Maximum Quantity. When

Purchaser accepts the Maximum Quantity, all of the amounts paid under this Section 2.15 will be allowed to be credited against future payments for oil tendered under this Agreement except for an amount to be retained by Seller equal to .75% of the Purchase Price per barrel per day on the difference between the Maximum Quantity and the Actual Quantity for each day Purchaser did not take the Maximum Quantity on and after the Date of First Delivery. If Purchaser should thereafter decrease the amount of Royalty Oil to be tendered under this Agreement, Purchaser shall pay to Seller, in addition to the Purchase Price, an amount equal to .75% of the Purchase Price per barrel per day after the date that the decrease in the amount of Royalty Oil to be tendered by Seller takes effect on the difference between the Maximum Quantity and the Actual Quantity.

ARTICLE III
REPRESENTATIONS AND OBLIGATIONS OF PURCHASER

Purchaser warrants, represents, and agrees:

3.1 Good Standing and Due Authorization. Purchaser is, and at all times during the operation of this Agreement shall remain, (a) a natural person who has reached the age of majority and who is a citizen of the United States; or (b) a corporation organized and existing under and by virtue of the laws of the United States or of any state, territory or the District of Columbia and qualified to do business in Alaska; or (c) any association of the foregoing. If a corporation, Purchaser has all necessary corporate power to enter into this Agreement and to perform its covenants and obligations under this Agreement, and all necessary corporate action has been taken to authorize Purchaser's entering into this Agreement and performing its covenants and obligations under this Agreement.

3.2 Financial Condition. The financial information submitted to Seller is complete and correct and fairly presents Purchaser's financial condition at the time the information was submitted to Seller. The financial information was prepared in accordance with generally accepted accounting principles consistently applied. Since the date the information was submitted, the condition, business and properties of Purchaser have not been materially adversely affected in any way. Purchaser agrees to inform Seller immediately if during the term of this Agreement there is any material adverse change in the condition, business, or properties of Purchaser which would have an appreciable adverse effect on Purchaser's ability to perform under this Agreement. Purchaser, in addition, will immediately inform Seller of any significant change in ownership of either Purchaser or any of its affiliates or parent company, and of any change in Purchaser's operations or agreements, which would appreciably affect Purchaser's performance under this Agreement.

3.3 Financial Statements. As soon as possible after the end of each fiscal year of Purchaser, and in any event within one hundred twenty (120) days thereafter, Purchaser will furnish to Seller, at Purchaser's sole cost and expense, a report or a complete copy of a report in a form to be prescribed from time to time by Seller which will include Purchaser's balance sheet as of the close of the fiscal year and the income statement for that year prepared in each case in accordance with generally accepted accounting principles consistently applied by certified public accountants of recognized standing. For purposes of complying with this section, Purchaser Chevron may submit, and Seller will accept, the annual report and supplement of Chevron Corporation.

ARTICLE IV
MEASUREMENTS AND TESTS

The quantity and quality of the oil sold under this Agreement shall be determined at the Point of Delivery. Procedures and methods for measuring and metering the oil sold under this Agreement shall be in accordance with the practices then in effect at the Point of Delivery specified under Section 2.5.

ARTICLE V

PAYMENTS AND ACCOUNTING

5.1 Billing. Seller will send to Purchaser, on or before the 10th (tenth) business day of each Month after the month of delivery of Oil, an invoice statement of account of all Oil estimated to have been measured at the Central Production Facility Meter into the Kuparuk Pipeline and tendered to Purchaser under this Agreement during the immediately preceding Month according to the best information available to Seller, the estimated Purchase Price(s) applicable to those deliveries, and the total amount due ("initial billing"). The estimates will be made by Seller according to the best information reasonably available to Seller. Seller shall thereafter adjust its initial billing under this section as soon as more accurate information concerning the quantity and Purchase Price(s) of Oil delivered each Month is available. Seller, however, shall not be required to adjust the initial billing prior to the sending of the next Month's invoice statement of account.

5.2 Initial Adjustment. After the first monthly invoice under Section 5.1, each subsequent monthly invoice will also state Seller's initial adjustments to be made, if any, to the invoice rendered in the immediately preceding Month, in accordance with any additional or more accurate information which may have become available to Seller. Whether or not initial adjustments are made, however, subsequent adjustments may be made under Section 5.5.

5.3 Payment. Purchaser will make payment of each amount billed under this section within ten (10) Days after receipt of the invoice statement of account. Payment shall be made without any deduction, set off, or withholding by wire transfer of immediately available funds to Seller's account at the following address:

First Pennsylvania Bank Philadelphia
ABA No. 031000024
For Credit to State of Alaska
Account No. 07/089250/00
Attn: Catherine Hess

Payment may be made in such other manner or to such other address as Seller may specify in the invoice statement of account or by other written notice. All other payments to be made under this Agreement shall be paid in the same manner. If payment is due on a Saturday, Sunday, or legal holiday of the place where payment is to be received, payment shall be made on the next following business day. It is recognized that Seller may bill, and that Purchaser will pay, amounts that are based upon confidential information held or received by Seller. If confidential information is used as the basis for a billing, then upon request Seller will furnish Purchaser with the certified statement of the Commissioner that the amounts billed are correct based upon the best information available to Seller. Buyer will only be permitted to review material or information that is not confidential. If a dispute concerning a bill arises, Purchaser agrees to pay the full amount billed by Seller, except for obvious clerical mistakes, pending final resolution of the dispute.

5.4 <u>Payment to Lessee(s)</u>. Purchaser, at the request of Seller in the invoice statement of account or otherwise in writing, shall pay all or any portion designated by Seller of the amount due to Seller to one or more of the Lessees at an address or addresses and in the manner designated by Seller. The payment will be made within the time limit specified in Section 5.3. Seller may authorize and designate a third party to make the request and designate the amount, manner and place of payment under this provision. Unless otherwise specified, the balance of the payment due, if any, and payments for subsequent months, shall be made in accordance with Section 5.3.

5.5 <u>Subsequent Adjustments</u>. Purchaser acknowledges that more accurate information concerning the quantity of or Purchase Price for Oil tendered may subsequently become available to Seller. In the event that any such information should subsequently become available to Seller, Seller shall promptly furnish a corrected invoice statement of account to Purchaser and the parties will adjust the amount billed and pay or refund the amount of those adjustments.

In the event that Seller should render a corrected invoice to Purchaser, any amount to be refunded from Seller to Purchaser or paid from Purchaser to Seller will be paid within fifteen (15) Days after the date of the corrected invoice, unless the adjustment concerns an amount last invoiced more than sixty (60) Days before the corrected invoice. In that case, the amount will be paid by Purchaser or refunded by Seller, as the case may be, in equal monthly installments over the same period of time as that over which the adjustment accrued or six (6) Months, whichever is the shorter period. No adjustment will be made more than twelve (12) Months after the date of the last original invoice to which the adjustment relates, except for adjustments resulting from regulatory or court proceedings (including appeals) commenced or pending during that twelve (12) month period, whether or not Seller or Purchaser is a party to the proceeding. Adjustments due to regulatory or court proceedings may be made at any time and shall bear interest at the rate stated in Section 5.6 from the date of payment of the invoice upon which an adjustment is subsequently made pursuant to this section. The provisions of this Section 5.5 will survive any termination of this Agreement.

5.6 Interest. Except for adjustments made upon resolution of *Amerada Hess* under Section 2.3, all sums which are not paid when due under this Agreement or which are subsequently determined to be due under an adjustment under Section 5.5, shall bear interest from the date accrued until paid in full at a variable rate per annum equal to the prime rate as announced from time to time by the Bank of America, San Francisco, California, plus one and one-quarter percent (1.25%) per annum.

5.7 Late Payment Penalty. Except for unintentional failures to pay, including clerical mistakes or occurrences not within the reasonable control of Purchaser, or insignificant underpayments, if Purchaser fails to make payment within one (1) Day of the date that payment is due, then in addition to the amount due plus interest from the date that payment was due until the date of payment, Purchaser will pay an amount equal to one percent (1%) of the amount owed.

5.8 Payment to Third Parties. Seller may direct that Purchaser pay any amount due to Seller or which may become due directly to a third party in the manner and time as may be directed by Seller in written notice to Purchaser if, in Seller's sole discretion, the payment to the third party will assist Seller in monitoring or enforcing this Agreement.

ARTICLE VI

TERM

This Agreement shall become effective upon execution by the parties and enactment of legislation by the State of Alaska (including approval by the Governor) approving this Agreement. This Agreement shall be null and voi if it is not so approved by September 30, 1986. Subject to the other provisions contained in this Agreement, Seller's obligation to sell and Purchaser's obligation to buy Royalty Oil shall begin as specified in Section 2.10, and shall end September 30, 1996. As used in this section, "enactment of legislation" is as defined in AS 01.10.070(f)(4).

ARTICLE VII

DEFAULT OR TERMINATION

7.1 Default. If any one or more of the follo g events ("Events of Default") occur, then at Seller's option, Seller may t nate or suspend its obligation to tender and sell Oil and proceed to exerc e any one or more of the rights and remedies provided in this Agreement:

(i) Except for obvious clerical errors, Purchaser does not pay in full any sum invoiced under this Agreement at the time when payment is due; or

(ii) Purchaser fails to observe or perf any of its other covenants and obligations under Artic or

(iii) Purchaser does not perform any act required or contemplated under this Agreement and either: (a) the nonperformance continues for more than thirty (30) days after Seller has notified Purchaser of Purchaser's nonperformance; or (b) Purchaser had failed to perform the same or any other act required or contemplated under this Agreement during the immediately preceding twelve (12) month period; or

(iv) There is a material adverse change in Purchaser's condition, business or property which appreciably affects the ability of Purchaser to perform any of its obligations under this Agreement, and Purchaser is unable to give Seller adequate assurance of continued performance either within fourteen (14) days of a request for such an assurance or within such other shorter time period as Seller may reasonably request under the circumstances; or

(v) Any representation or warranty made by Purchaser in this Agreement proves to have been false or incorrect in any material respect at the time that the representation or warranty was made.

7.2 Failure to Pay Debts. If at any time Purchaser becomes unable to pay any of its debts when those debts are due, or should otherwise become insolvent (without regard to how that insolvency may be evidenced), Purchaser will immediately give notice of that fact to Seller. Whether or not that notice is given, if Purchaser becomes unable to pay any of its debts when those debts are due or should otherwise become insolvent, Seller's obligation to tender and sell Oil under this Agreement will automatically and immediately terminate without any requirement of notice or other action by Seller; however, Purchaser will nevertheless be and remain liable for payment and performance of all of its obligations and covenants under this Agreement with respect to Oil actually tendered by Seller to and after any such termination. Within thirty (30) days after receipt of Purchaser's notice or, if no notice is given, after Seller otherwise becomes aware (as determined in Seller's sole discretion) of Purchaser's insolvency, Seller will have the right, upon written notice to Purchaser, to reinstate all of Seller's and Purchaser's obligations under this Agreement retroactively to the date of termination.

7.3 <u>Seller's Remedies</u>. Upon the occurrence of any Event of Default or if Seller's obligation to tender and sell Oil under this Agreement is terminated or suspended under Sections 7.1 and 7.2, all obligations of Purchaser accrued but not otherwise due and payable under this Agreement will immediately be due and payable in full. In addition, Purchaser will indemnify and hold Seller harmless from and against all other liability, damages (including reasonably foreseeable consequential damages), costs, losses and expenses (including reasonable attorneys' fees and disbursements) incurred by Seller and arising out of the Event of Default, termination, or suspension. Seller shall have the right cumulatively to exercise any and all other rights and remedies and to obtain all other relief available under applicable law or at equity, including mandatory injunction and specific performance. Seller, upon occurrence of any Event of Default, in its sole discretion, may arrange for any disposition to third parties of Oil to be tendered and sold under this Agreement. Upon the occurrence of any Event of Default, Purchaser is released from the obligations set forth in Sections 2.11 (In-State Processing) and 2.12 (Best Efforts) until the Event of Default no longer exists or the obligation of Purchaser to take Royalty Oil under this Agreement expires. If upon occurrence of any Event of Default Seller makes arrangement for disposition to third parties of Oil whether or not this Agreement is terminated, Purchaser will nevertheless be and remain liable to Seller for the full amount of the Purchase Price for that Oil in excess over any amount or amounts received by Seller on account of that disposition, net of the expenses of that disposition and for all other costs, losses and expenses (including reasonable attorneys fees and disbursements) incurred by Seller and arising out of the Event of Default or disposition.

7.4 Purchaser's Exclusive Remedies. Upon any breach of, or default in, the due and timely observance or performance of any of Seller's covenants or obligations under this Agreement, Purchaser acknowledges and agrees that Purchaser's remedies will not include a temporary restraining order or preliminary injunction preventing Seller from taking any action with regard to the Oil which is the subject of this Agreement.

ARTICLE VIII
DISPOSITION OF OIL

8.1 Inability to Receive Oil. Purchaser acknowledges and agrees that under the Unit Agreement and Leases, Seller's election to take Royalty Oil in kind can be revoked or reversed only upon the satisfaction of various conditions, including the giving of thirty (30) days advance written notice to return up to 2500 barrels of Seller's then current nominations. Purchaser acknowledges and agrees that Seller's election to invoke its rights to return to taking its Royalty Oil in value on less than six (6) months' prior notice, or to attempt to secure a waiver of any condition or requirement, is at Seller's sole and complete discretion. If for any reason Purchaser is unable or refuses to accept or receive any Oil tendered under this Agreement, Purchaser shall nevertheless be and remain responsible for the disposal of that Oil and for paying Seller for the Oil as though it had been received and accepted by Purchaser unless Seller, in its sole discretion elects to waive this requirement. In order to secure the obligations of Purchaser under this Section 8.1 and under Section 2.8, Purchaser shall, if and as Seller may request from time to time, assign to Seller all right, title and interest of Purchaser under any nominations, leases, agreements, contracts, charter parties and other arrangements for the transportation of the Oil sold under this Agreement through and away from the Kuparuk Pipeline and the Trans Alaska Pipeline System; provided, that Seller shall not have any liability or obligations under any such nominations, leases, agreements, contracts, charter parties or other arrangements unless, and to the extent that, Seller shall actually exercise its rights to succeed to Purchaser's interest thereunder and shall obtain the benefits thereof.

8.2 No Right to Storage or Underlift. Purchaser waives and disclaims any interest or right that it may assert to storage of Royalty Oil, including by underlift or other means, to which Seller is or may come to be entitled under the Leases, Storage Agreement, or any other agreement. However, Purchaser shall use due diligence and make its best efforts to act in a manner that enables Seller to adhere to the notice requirements and other obligations provided in the Storage Agreement. Purchaser agrees that when it executes this Agreement, it will also immediately execute the release attached as Exhibit B to this Agreement.

ARTICLE IX
WAIVER

The failure of either party to insist upon strict performance of any provision of this Agreement shall not constitute a waiver of, or estoppel against, asserting the right to require that performance in the future. A waiver or estoppel in any one instance shall not constitute a waiver or estoppel with respect to a later breach of a similar nature or otherwise. A course of performance established by a party shall also not stop the other party from complaining of a later breach similar in nature.

ARTICLE X
SEVERABILITY

If any provision or clause of this Agreement or application of this Agreement to any person or circumstance is held invalid, that invalidity shall not affect other provisions or applications of this Agreement which can be given effect without the invalid provision or application. If, however, an invalidity should operate to impair any material right or remedy of a party to this Agreement, that party may terminate this Agreement by notice to the other.

ARTICLE XI

FORCE MAJEURE AND CHANGE IN CONDITION

11.1 Effect of Force Majeure. Except for Purchaser's obligations to make payment of money for Oil tendered under this Agreement and except for Purchaser's obligations to accept and dispose of Royalty Oil, neither party shall be liable for any failure to perform the terms of this Agreement when the failure is due in whole or in substantial part to force majeure. The term "force majeure" as applied to this Agreement shall mean Acts of God, strikes, lockouts and industrial disputes or disturbances, civil disturbances, arrests and restraints from rulers or people, interruptions by government or court orders or by present or future orders of any regulatory body having or asserting jurisdiction, acts of the public enemy, wars, riots, blockades, insurrections, inability to secure materials by reasons of allocations promulgated by authorized governmental agencies, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or pipelines, or any other event or condition, whether of the kind herein enumerated or otherwise, not within the reasonable control of the party claiming the benefit of this excuse. If however, any material obligation of Purchaser is excused or suspended because of a claim of force majeure for a period of three hundred sixty five (365) successive days or more, Seller will have the right to terminate this Agreement. Prior to Seller exercising its right to terminate this Agreement Seller and Purchaser shall enter into good faith negotiations to restore, to the fullest extent possible, Seller and Purchaser to the benefits and obligations that existed under this Agreement before the occurrence of the force majeure condition.

11.2 Responsibility. Upon the occurrence and discovery of an event providing the basis for a claim of force majeure, the party making a claim shall notify the other party to this Agreement of its claim of force majeure. Upon the occurrence of an event constituting force majeure that event shall, so far as possible, be remedied with all reasonable diligence and dispatch. Except for Purchaser's obligations to make payment of money for Oil tendered under this Agreement and except for Purchaser's obligation to dispose of Oil, the obligations of the disabled party to perform under this Agreement, insofar as they are affected by that force majeure, shall be suspended from the time that force majeure occurs and for so long as the disability caused should have continued had the party claiming the existence of the force majeure remedied the event providing the basis of the claim of force majeure with reasonable diligence and dispatch, and for no longer. The settlement of strikes or lockouts or industrial disputes or disturbances will be entirely within the discretion of the party having the difficulty, and the above requirement that any force majeure shall be remedied with diligence and dispatch shall not require the settlement of strikes, lockouts, or industrial disturbances by acceding to the demands of any opposing party therein when such course is inadvisable in the sole discretion of the disabled party.

ARTICLE XII

NOTICES

12.1 Method. All notices, requests, demands or statements shall be in writing, and may be delivered personally to the party to be notified or may be sent to the party by registered or certified United States mail, postage prepaid, with a return receipt requested of the party. Notice deposited in the mail in this manner shall be effective upon the expiration of seven (7) days after it is so deposited. Notice given in any other manner shall be effective only if and when received by the addressee. For the purposes of notice, the addresses of the parties to this Agreement shall be as follows:

If to Seller:

State of Alaska
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99811

and

Commissioner of Revenue
Pouch "S"
Juneau, Alaska 99811

and

Director, Division of Oil and Gas
Pouch 7-034
Anchorage, Alaska 99510

Telephone:

Telex:

If to Purchaser Petro Star:

Telephone:

Telex:

If to Purchaser Chevron:

Telephone:

Telex:

12.2 Change of Address. Each party may change its address for notice by giving notice of the change.

ARTICLE XIII
RULES AND REGULATIONS

This Agreement is subject to all present and future valid laws, orders, rules and regulations of the United States, the State of Alaska, and any duly constituted agency thereof.

ARTICLE XIV

SOVEREIGN POWER OF THE STATE

This Agreement and its covenants shall not be interpreted as a limit on the exercise by the State of Alaska of any of its sovereign or regulatory powers, whether conferred on the State by constitution, statute or regulation, including but not limited to, its regulatory power over the Leases. The exercise by the State of Alaska of any sovereign or regulatory power will not operate or be deemed to enlarge any rights of Purchaser or to limit or impair any obligations or liability of Purchaser under this Agreement, except for state statutes enacted after the effective date of this Agreement which have a direct and significant adverse effect on the ability of Purchaser to perform an obligation under this Agreement other than the obligations to accept, dispose of, and pay for Oil tendered under this Agreement.

ARTICLE XV

SECURITY

15.1 Purchaser Chevron Letter of Credit. Sixty (60) days prior to Date of First Delivery, Purchaser Chevron shall cause to be issued and delivered to Seller an irrevocable stand-by letter of credit, with an effective date no later than the Date of First Delivery, issued for the benefit of Seller by a state or national banking institution of the United States ("Issuer"), which is insured by the Federal Deposit Insurance Corporation and has an aggregate capital and surplus of not less than One Hundred Million Dollars ($100,000,000), or other banking institution acceptable to Seller in its sole discretion. The principal face amount of such letter of credit shall be a sum estimated by the Commissioner to be equal to the aggregate Purchase Price for the approximate total amount of Oil to be tendered by Seller to Purchaser Chevron during the first ninety (90) days following the Date of First Delivery, calculated at the Purchase Price. The letter of credit shall be substantially in a form satisfactory to the Commissioner, but in any event shall not require any documents to be submitted in support of drafts drawn against this letter of credit other than the certified statement of the Commissioner or her designee and the Attorney General of the State of Alaska or his designee that Purchaser Chevron is liable to Seller for a sum equal to the amount of such draft, and that that sum is due and payable in full and has not been timely paid.

In the event that Seller should have reasonable grounds for asserting any claims against Purchaser Chevron under this Agreement and does assert those claims in an aggregate amount in excess of the aggregate principal face amount of the letter of credit then in effect, Purchaser Chevron shall upon Seller's request (whether or not Purchaser Chevron may deny, reject or otherwise resist such claims) cause the principal face amount of the letter of credit to be increased by an amount equal to the excess. The principal face amount of the letter of credit shall also be automatically increased by Purchaser Chevron without request from Seller whenever the face amount is less than the expected Purchase Price of ninety (90) days of Oil tenders to Purchaser Chevron under this Agreement, to an amount equal to the expected Purchase Price of ninety (90) days of Oil tenders to Purchaser Chevron. The principal face amount of the letter of credit may be decreased by Purchaser Chevron upon approval of Seller if the face amount is more than the expected Purchase Price of ninety (90) days of Oil tenders to Purchaser Chevron under this Agreement, to an amount equal to the expected Purchase Price of ninety (90) days of Oil tenders to Purchaser Chevron.

The letter of credit must allow drafts to be drawn and presented to the Issuer up to and including the 90th day after the last delivery of Royalty Oil to Purchaser Chevron under this contract. The Commissioner may accept such other or additional security as she, in her sole discretion, considers adequate to protect Seller.

15.2 Purchaser Petro Star Letter of Credit. Sixty (60) days prior to the Date of First Delivery, Purchaser Petro Star shall cause to be issued and delivered to Seller an irrevocable stand-by letter of credit, with an effective date no later than the Date of First Delivery, issued for the benefit of Seller by a state or national banking institution of the United States ("Issuer"), which is insured by the Federal Deposit Insurance Corporation and has an aggregate capital and surplus of not less than One Hundred Million Dollars ($100,000,000), or other banking institution acceptable to Seller in its sole discretion. The principal face amount of such letter of credit shall be a sum estimated by the Commissioner to be equal to the aggregate Purchase Price for the approximate total amount of Oil to be tendered by Seller to Purchaser Petro Star during the first sixty (60) days following the Date of First Delivery, calculated at the Purchase Price. The letter of credit shall be substantially in a form satisfactory to the Commissioner, but in any event shall not require any documents to be submitted in support of drafts drawn against this letter of credit other than the certified statement of the Commissioner or her designee and the Attorney General of the State of Alaska or his designee that Purchaser Petro Star is liable to Seller for a sum equal to the amount of such draft, and that that sum is due and payable in full and has not been timely paid.

In the event that Seller should have reasonable grounds for asserting any claims against Purchaser Petro Star under this Agreement and does assert those claims in an aggregate amount in excess of the aggregate principal face amount of the letter of credit then in effect, Purchaser Petro Star shall upon Seller's request (whether or not Purchaser Petro Star may deny, reject or otherwise resist such claims) cause the principal face amount of the letter of credit to be increased by an amount equal to the excess. The principal face amount of the letter of credit shall also be automatically increased by Purchaser Petro Star without request from Seller whenever the face amount is less than the expected Purchase Price of sixty (60) days of Oil tenders to Purchaser Petro Star under this Agreement, to an amount equal to the expected Purchase Price of sixty (60) days of Oil tenders to Purchaser Petro Star. The principal face amount of the letter of credit may be decreased by Purchaser

Petro Star upon approval of Seller if the face amount is more than the expected Purchase Price of sixty (60) days of Oil tenders to Purchaser Petro Star under this Agreement, to an amount equal to the expected Purchase Price of sixty (60) days of Oil tenders to Purchaser Petro Star.

The letter of credit must allow drafts to be drawn and presented to the Issuer up to and including the 60th day after the last delivery of Royalty Oil to Purchaser Petro Star under this contract. The Commissioner may accept such other or additional security as she, in her sole discretion, considers adequate to protect Seller;

15.3 Purchaser Petro Star Amerada Hess Escrow. Sixty (60) days prior to the Date of First Delivery, Purchaser Petro Star shall cause to be executed and delivered to Seller an executed escrow agreement with a state or national banking institution of the United States ("Escrow Bank"), which is insured by the Federal Deposit Insurance Corporation, and which has a aggregate capital and surplus of not less than One Hundred Million Dollars ($100,000,000), or other banking institution acceptable to the Seller in its sole discretion. The escrow agreement shall be in a form satisfactory to the Commissioner. The escrow agreement shall provide for payment of escrowed amounts only after final resolution of the Amerada Hess litigation, including any appeals, and upon tender of a certified statement, signed by the Commissioner of Natural Resources and the Attorney General of the State of Alaska. The certified statement shall specify the disposition of the principal and accrued interest of the escrow as calculated under the provisions of Articles II and V of this Agreement, with the full adjusted Purchase Price and interest payable to Seller, and any escrow balance payable to Purchaser Petro Star. Before requesting escrow payment, Seller will give Purchaser Petro Star at least twenty (20) days written notice of its calculations for the escrow disposition.

Purchaser Petro Star agrees to make monthly deposits into the escrow of the sum equal to $1.12 per barrel of Royalty Oil purchased by Purchaser Petro Star from Seller under this Agreement during the previous month. This sum represents a negotiated escrow amount, and is not any party's estimate of litigation results. The amount of this escrow shall be an element of the "Purchase Price" under this Agreement, and shall be subject to periodic renegotiation as specified in the purchase price reopener provision of Section 2.4.

Purchaser Petro Star shall make payments to the escrow at the same time as it pays Seller under Article V of this Agreement, including increased payments necessitated by quantity adjustments under that Article. Purchaser Petro Star shall bear all expenses of the escrow, and shall arrange for the Escrow Bank to send to Seller monthly statements showing the escrow balance.

15.4 Chevron Backup. Purchaser Chevron agrees that, after receiving at least five (5) days notice from Seller, it will accept delivery of any volumes of Royalty Oil upon which Purchaser Petro Star has defaulted under this Agreement. The notice referenced above shall be given by telephone and by telex to the telephone number and address provided in Section 12.1. Purchaser Chevron agrees to take those volumes subject to all the terms of this Agreement, except that the price for those volumes shall be the Petro Star Purchase Price. Purchaser Chevron will promptly increase its letter of credit to include the increased volume. The Commissioner will return the defaulted volumes to in value as soon as possible, and will promptly notify Purchaser Chevron of the date on which deliveries to it under this section will cease.

ARTICLE XVI

PREFERENTIAL HIRING

Purchaser agrees to hire and employ Alaska residents and Alaska companies to the extent they are available, willing and qualified for all work performed in Alaska under or in connection with this Agreement, including but not limited to construction and operation of facilities to refine or otherwise use the Royalty Oil. As used in this Agreement "Alaska resident" means an individual who has resided in the State for one year at the time of hiring or employment and "Alaska companies" means those companies who are incorporated in the State of Alaska or whose principal place of business is in Alaska. Seller acknowledges that under the arrangements initially contemplated under this Agreement, Purchaser Chevron will not be performing work in Alaska under or in connection with this Agreement.

If this provision is determined to be unconstitutional by a court of competent jurisdiction, then Purchaser agrees to hire and employ Alaska residents and Alaska companies to the extent such preferential hiring is determined to be constitutional.

ARTICLE XVII

APPLICABLE LAW

17.1 Alaska Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Alaska, excluding any conflict-of-law rule or principle which might refer such construction to the laws of another state or country.

17.2 Submission to Jurisdiction. Any legal action or proceeding arising out of or relating to this Agreement or for the enforcement of the covenants or obligation of either party must be instituted in a State court of general jurisdiction sitting in the State of Alaska, and Purchaser hereby irrevocably submits to the jurisdiction of that court in any such action or proceeding.

ARTICLE XVIII
NO WARRANTIES

The purchase and sale of Royalty Oil under this Agreement is subject only to the warranties of Seller expressly set forth in this Agreement and Seller disclaims and Purchaser waives all other warranties, express or implied in law, whatsoever.

ARTICLE XIX
AMENDMENT

This Agreement may be supplemented, amended or modified at any time, but only by written instrument duly executed by the parties to this Agreement. Any material amendment to this contract that appreciably reduces the consideration received by the state requires prior approval of the legislature.

ARTICLE XX
SUCCESSORS AND ASSIGNS

No assignment, pledge or encumbrance of this Agreement shall be made by either Purchaser without first obtaining the written consent of Seller, or by Seller without obtaining the written consent of both Purchasers. The Commissioner may grant such consent on behalf of Seller. The Commissioner shall have sole and complete discretion in granting or denying a proposed assignment, pledge or encumbrance. Subject to the above requirements in this Article, this Agreement will be binding upon and inure to the benefit of each of the parties and its successors and permitted assigns. In addition, if Purchaser gains or acquires a controlling interest in an entity which has an agreement with Seller for the sale of Oil ("Other Agreement"), then Seller, at its option and on thirty Days' prior notice, may require Purchaser to terminate either this Agreement or the Other Agreement. The choice of which

Agreement to terminate will be Seller's. Purchaser may request that Seller waive this provision in advance of Purchaser gaining a controlling interest in an entity which has an agreement with Seller for the sale of Oil. The Commissioner has sole and complete discretion in granting or denying the requested waiver.

ARTICLE XXI
HEADINGS

Headings used in this Agreement are for convenience only and shall not affect the construction of this Agreement.

ARTICLE XXII
RECORDS

22.1 Preservation of Records. Purchaser will preserve and maintain all books, accounts, and records directly relating to the performance of this Agreement, including but not limited to the purchase or sale of Oil and its refined products, for a period of six (6) years. Purchaser will also maintain and preserve all similar books, accounts, and records of which it has possession belonging to those third parties with whom it contracts for the performance of various parts of this Agreement. Neither Purchaser nor Seller shall be required to retain any records for more than six (6) years unless retention of such records is specifically required by applicable law or regulation. Purchaser shall either maintain its records within the State of Alaska or make such records available to Seller at Purchaser's principal office in the State of Alaska within thirty (30) days after written request by Seller.

22.2 Inspection of Records of Parties. Purchaser and Seller will accord to each other and to their authorized agents, attorneys, and auditors during reasonable business hours access to any and all property, records, books, documents, and indexes directly relating to Purchaser's or Seller's performance of this Agreement and which are under the control of the party from which access is desired, so that the other party may inspect, photograph and make copies of that property, records, books, documents and indexes. In no event, however, shall Seller be required to disclose any information, data, or records which are required to be held confidential by state law or regulation. If the information obtained by Seller may be held confidential under state or federal law or regulation, Purchaser may request that that information be held confidential by Seller.

ARTICLE XXIII
INTERPRETATION OF TERMS AND CONDITIONS

In the event that there is a disagreement about the meaning or application of a word, term, or condition in this Agreement, Purchaser will present the arguments supporting its view in writing to the Commissioner for her consideration. The Commissioner will subsequently, within a reasonable time, issue a finding on the meaning or application of the disputed word, term, or condition, setting forth the basis for her conclusions. Purchaser agrees to accept findings by the Commissioner under this Article as long as there is substantial evidence supporting the Commissioner's findings.

DATED this 9th day of December, 1985

SELLER: THE STATE OF ALASKA

~~Commissioner~~ Director

Department of Natural Resources

PURCHASER PETRO STAR, INC.: PETRO STAR, INC.

By ______________________

President

PURCHASER CHEVRON: CHEVRON U.S.A. INC.

By ______________________

3928s

EXHIBIT B

RELEASE

For a valuable consideration, the receipt and adequacy of which are acknowledged, the undersigned does hereby release and forever discharge ARCO Alaska, Inc., BP Alaska Exploration Inc., Chevron U.S.A. Inc., Exxon Corporation, Mobil Oil Corporation, Phillips Petroleum Company, Sohio Alaska Petroleum Company, Union Oil Company of California, Amoco Production Company, individually and collectively, and each of their predecessors, successors, assigns, and all persons acting by, through, under or in concert with them, or any of them (the "Releasees"), of and from any and all claims, demands or causes of action of any nature whatsoever, known or unknown, fixed or contingent, hereinafter made against the Releasees, or any of them arising out of, based upon, or relating to the purported storage rights of the State of Alaska with respect to royalty oil produced from the land as to which the Kuparuk River Unit Agreement is now effective on to which it may be extended.

The undersigned represents and warrants that there has been no assignment or other transfer of any interest in any claim which agrees to indemnify and hold Releasees, and each of them, harmless from any liability, claims, demands, damages, costs, expenses and attorney's fees incurred by Releasees, or any of them, as a result of any person asserting assignment or transfer or any rights or claims under that assignment or transfer. It is the intention of the parties that this indemnity does not require payment as a condition precedent to recovery by the Releasees against the undersigned under this indemnity.

The undersigned agrees that if after execution of this Release the undersigned commences, joins in, or in any manner seeks relief through any suit arising out of, based upon, or relating to any of the claims released under this Release or in any manner asserts against Releasees, or any of them, any of the claims released under this Release, then the undersigned will pay to Releasees, and each of them, in addition to any other damages caused to Releasees by that action or claim all attorney's fees incurred by Releasees in defending or otherwise responding to the action or claim.

The undersigned further understands and agrees that the execution of this Release shall neither consitute nor be construed as an admission by the Releasees, or any of them, that they have any storage obligation with respect to the State's royalty oil.

Stephen T. Lewis	5 December 1985
PETRO STAR, INC.	DATE
A W Carcamo	6 December 1985
CHEVRON U.S.A.	DATE

Chevron

Chevron U.S.A. Inc.
2950 Buskirk Avenue, Walnut Creek, California
Mail Address: P.O. Box 9000, Concord, CA 94524

Supply & Distribution Department
Western Region
J. F. Menear
Manager, Supply

Assistant Managers
T. A. Hecht
Product Supply
L. W. Corbett, Jr.
Raw Material Supply

CRUDE OIL PURCHASE-SALE AGREEMENT

BETWEEN

CHEVRON U.S.A. INC. AND PETRO STAR OIL COMPANY

CHEVRON CONTRACT NO. 165608

PETRO STAR CONTRACT NO. C86001

DECEMBER 1, 1985

This document, when duly executed, evidences our Crude Oil Purchase and Sales Agreement (hereinafter called Agreement) by and between Chevron U.S.A. Inc., a Pennsylvania corporation, (hereinafter called Chevron) and Petro Star Oil Company, an Alaska corporation, (hereinafter called Petro Star) to purchase and sell crude oil of the quantity and quality specified under the terms and conditions set forth below:

1. **Term:** This Agreement shall be effective upon commencement of the Royalty Oil Contract, DNR #10-4017, (State Contract) between the State of Alaska, Petro Star and Chevron and will be cancelled at the same time that the State Contract is cancelled. Nominally, the term of the State Contract is up to ten years, ending September 30, 1996, but the State Contract can be reduced or cancelled on nine months notice. If Chevron's purchase of Royalty Oil under the State Contract is reduced or cancelled for any reason, then Chevron shall have the right to reduce or cancel this Agreement at the same time.

2. **Chevron Delivery:** Chevron shall deliver and Petro Star shall receive that percentage of Royalty Oil purchased by Chevron under the State Contract (approximately 4,000 barrels per day) of Kuparuk Royalty Oil and delivered to Pump Station #1. Title and Risk of Loss shall pass from Chevron to Petro Star as the crude oil passes the LACT measurement at Pump Station #1 Trans-Alaska Pipeline (TAPS).

3. **Petro Star Delivery:** Petro Star shall deliver and Chevron shall receive an equal volume to that delivered by Chevron in item 2 above (approximately 4,000 barrels per day) of Alaskan North Slope Common Stream into Chevron's nominated vessel at Valdez, Alaska. Petro Star will incur any actual intransit losses between Pump Station #1 and Valdez. Title and Risk of Loss shall pass from Petro Star to Chevron as the crude oil passes the last permanent flange connecting shore facilities to Chevron's nominated vessel at the Valdez terminal.

4. **Price:** Chevron shall sell to Petro Star at Pump Station #1 at a price of \$17.00 per barrel for 27^{o} API oil adjusted by the actual Trans Alaska Pipeline system quality bank adjustment in effect at time of delivery for gravities above and below 27^{o} API. Chevron will purchase from Petro Star at Valdez at the same price (\$17.00 per barrel for 27^{o} API) adjusted for actual gravity received on the same basis, plus the weighted average TAPS tariff for all deliveries through TAPS in effect for the month of delivery.

There shall be no adjustments of the \$17.00 price because of the State of Alaska et al v. Amerada Hess Corp., et al case. The invoice price in this contract is for the purpose of settlement of time value of money differences between delivery and receipt of oil.

5. **Invoices:** Invoices shall be sent by the tenth (10th) day of the month following the month of delivery.

6. **Payments:** Payment shall be made to the appropriate address stated herein by the 20th day of each month for deliveries made during the preceding month.

Payments due Chevron:	Payments due Petro Star:
Chevron U.S.A. Inc. Account No. 010-431026 Crocker National Bank 55 Sansome Street San Francisco, CA	Petro Star, Inc. Account No. 84-02371-2 Alaska Mutual Bank Minnesota-Benson Branch 1500 West Benson Blvd. Anchorage, AK

7. **Basis of Settlement:** This Agreement shall be on an equal volume basis. Any difference in quantities delivered each month shall be carried forward. Any remaining barrel balance shall be liquidated by delivery of the crude oil within 60 days of termination of this Agreement or any other mutually acceptable procedure.

8. **Gauging and Sampling:** The quantity and quality of all crude oil delivered hereunder via pipeline shall be determined by an approved LACT unit at Pump Station #1 or Valdez as appropriate.

9. **Credit:** Petro Star shall post an irrevocable standby Letter of Credit in a form acceptable to Chevron for approximately $4,150,000. Said Letter of Credit shall be continuously in effect for 60 days beyond date of delivery or shall have renewable features acceptable to Chevron. Chevron shall receive said Letter of Credit prior to making any deliveries.

10. **Notice:** Any notice hereunder shall be in writing and shall be transmitted by personal delivery, telegram, telex, telefax or mail to the following addresses or to such other addresses as either party may designate in writing:

Invoices, payments and accounting matters:

Chevron U.S.A. Inc. P.O. Box W, Section 427 Concord, CA 94524 TELEX: 335-329 CHEV SPLY WNCK TELECOPY: (415) 944-8989	Petro Star, Inc. P. O. Box 56239 North Pole, AK 99705 TELEX: 36-686 TELECOPY: (907) 488-9057

All other correspondence:

Chevron U.S.A. Inc. Attn: Western Region, S&D P.O. Box 9000 Concord, CA 94524 TELEX: 176967 CHEVCORP SFO TWX: 9103727340 CHEVCORP SFO TELECOPY: (415) 944-6269	Petro Star, Inc. P. O. Box 56239 North Pole, AK 99705 TELEX: 36-686 TELECOPY: (907) 488-9057

11. **Marine Provisions:** Marine Provisions per TAPS port information manual will supersede Chevron Marine Provisions dated April 1, 1984 where appropriate. Otherwise, the Chevron U.S.A. Crude Oil Marine Provisions dated April 1, 1984 attached hereto are included in and made part of this Agreement. In case of conflict between the terms and conditions above and the Crude Oil Marine Provisions, the terms and conditions above shall apply.

12. **General Provisions:** Chevron's General Provisions dated September 1, 1983 will be attached to and made a part of this Agreement. In case of conflict between the terms and conditions above and the General Provisions, the above terms and conditions shall apply. Usual industry practice shall apply for conditions not covered by the above terms and conditions or by the General Provisions.

The undersigned, as authorized parties, agree to the above terms and conditions.

AGREED:

PETRO STAR OIL COMPANY

By_______________

Stephen T. Lewis

Date January 10, 1986

AGREED:

CHEVRON U.S.A. INC.

By AM Caccamo

A. M. Caccamo

Date January 8, 1986

CHEVRON U.S.A. INC. **September 1, 1983**

CRUDE OIL GENERAL PROVISIONS

1. **DEFINITIONS:** When used in this Agreement, the terms listed below have the following meanings:

   "Affiliate" means a corporation controlling, controlled by or under common control with either party.

   "API" means the American Petroleum Institute.

   "ASTM" means the American Society for Testing and Materials.

   "Barrel" means forty-two (42) United States gallons at sixty degrees Fahrenheit (60°F) of crude oil after deducting any S&W present, unless otherwise noted. This measurement corresponds to the "Net Standard Volume," in barrels at 60°F, as defined in the Annex to Chapter 1, API Manual of Petroleum Measurement Standards dated October 1981.

   "B/D" means barrels per calendar day.

   "S&W" means sediment and water.

   "Day", "Month", and "Year" mean, respectively, calendar day, calendar month and calendar year unless otherwise specified.

   "Crude Oil" means crude oil and/or crude condensate, as appropriate.

   "FOB", "C.I.F.", and "C&F" shall be as defined in the latest edition of Incoterms.

2. **FINANCIAL RESPONSIBILITY:** If, during the term of this Agreement, the financial responsibility (including, but not limited to, either party's ability to perform under Warranty of Title) of the owing party becomes impaired or unsatisfactory to the other party, then in any such case advance cash payment, properly endorsed negotiable bills of lading, or satisfactory security shall be given upon demand, and performance hereunder may be withheld until such payment, bills of lading or security is received. If such payment, bills of lading, or security is not received within fifteen (15) days from demand therefor, the demanding party may terminate this Agreement. In the event either party makes an assignment for the benefit of creditors or any general arrangement with creditors, or if there are instituted by or against either party proceedings in bankruptcy or under any insolvency law or law for reorganization, receivership or dissolution, the other party may withhold shipments or terminate this Agreement without notice. The exercise by either party of any right under this paragraph shall be without prejudice to any claim for damages or any other right under this Agreement or applicable law.

3. **OFFSET:** In the event either party shall fail to make timely delivery of any crude oil, due and owing to the other party, or in the event either party shall fail to make timely payment of any monies due and owing to the other party, the other party may offset any deliveries or payments due under this or any other agreement between the parties and their affiliates.

4. **NECESSARY DOCUMENTS:** Each party hereto agrees to furnish to the other party to the best of its ability all available substantiating documents incident to the transaction, including a satisfactory source document for each volume delivered and an invoice for any month in which the sums are due.

5. **MUTUAL AGREEMENT REGARDING TERMINATION:** The parties hereto do not intend to create between them by this Agreement a continuing obligation to buy, sell, or exchange crude oil other than as specified in the termination provisions contained elsewhere herein. Accordingly, the parties hereby mutually agree to said termination provisions, and each party hereby expressly waives any rights it may have under any existing or future state or federal government regulations which would insist upon the continued supply of crude oil provided herein.

6. **TITLE:** Title to and risk of loss of the crude oil delivered hereunder shall pass from the delivering party to the receiving party as the crude oil is delivered into the receiving party's facilities designated elsewhere in this Agreement.

   For marine deliveries, title and risk of loss of cargo shall pass at the vessel's last permanent flange connecting to the terminal, provided however, any loss of or damage to the cargo during loading or discharging caused by the fault of the vessel shall be for the account of the party delivering from/receiving onto such vessel.

7. **WARRANTY:** The delivering party warrants (a) that it has good and sufficient legal title to the crude oil delivered by it hereunder and its right to deliver same, (b) that said oil has been produced, handled and transported to the delivery point hereunder in accordance with the laws, rules and regulations of all local, state or federal authorities having jurisdiction thereof.

   The delivering party agrees to indemnify and hold receiving party harmless from and against any loss, claim or demand by reason of any failure of such title to such crude oil or failure or breach of this warranty.

8. **QUALITY:** Neither party shall be obligated to accept crude oil containing S&W in excess of 1% (3% for production in California) by volume or local pipeline requirements, whichever is less.

   Crude oil delivered hereunder shall be merchantable, virgin crude oil free of organic chlorides, oxygenated hydrocarbons, lead and any other contaminants not normally associated with crude oil, and acceptable to the carriers involved.

9. **TESTS AND MEASUREMENTS:** All gauging, sampling, and testing of deliveries shall be made in accordance with the latest approved methods of the API for the delivery method in then current general use at the point of delivery. Full deduction shall be made for S&W, such determination shall be made according to API Petroleum Measurement Manual, Chapters 10.1 & 10.2. (water by distillation and sediment by extraction, currently same as ASTM D-473 and D-4006) at those locations which regularly measure S&W in this manner. At other locations, such determination to be made in accordance with API Petroleum Measurement Manual, Chapter 10.3 (centrifuge method, currently same as ASTM D-4007) in its then latest revision. Each party may have a representative present at all gauging, sampling, and testing of the oils delivered hereunder. If one party does not make a representative available to witness gauging, sampling, and testing, the results determined by the representative present shall be binding on both parties. It is agreed that independent commercial inspection shall not be employed to witness pipeline or truck deliveries hereunder, provided however, that other party shall have the right to request and pay for such inspection.

The quantity of marine deliveries shall be determined by acceptable custody transfer meter, if available, or by shore tank ga at the terminal. The quality and quantity of marine deliveries shall be determined by a mutually acceptable licensed petroleu inspector with costs shared equally. Findings of the independent marine inspector shall be binding on both parties.

10. **FORCE MAJEURE:** In the event either party is rendered unable, wholly or in part, to perform its obligations under this Agreement (other than to make payments due hereunder) due to acts of God, floods, fires, explosions, weather, strikes, lockouts or other industrial disturbances, wars or any law, rule, order or action of any court or instrumentality of the federal or any state government, or due to exhaustion, reduction or unavailability of crude oil at the source of supply from which deliveries are normally made hereunder, or any other cause or causes (except financial) beyond its control whether similar or dissimilar to those stat above, it is agreed that the obligations of each party shall be suspended for the continuance of any inability so caused but for no longer period. The party claiming force majeure shall immediately notify the other party promptly of the nature and estimated duration of such inability to perform. The cause of such inability to perform shall, so far as possible, be remedied with all reasonable dispatch.

If, by reason of such cause, making or accepting deliveries is curtailed in part, the party prevented from accepting or making deliveries of the contract volume may apportion fairly the volumes it can deliver or accept in the ordinary course of business among its suppliers or customers, whether or not under contract. In the event of such apportionment, the volume of the other party's deliveries or receipts will be reduced in a like amount.

11. **PERSONAL PROPERTY TAX ON EXCHANGE DELIVERIES:** When applicable, property taxes on any crude oil exchange balance existing hereunder on tax assessment date each year will not become a lien and the party to whom the oil is due will not be required to reimburse the other party for any property taxes levied thereon unless specific agreement to the contrary has been reached by the parties prior to the applicable tax assessment date of that year. In the event such agreement has been made, the invoices requiring payment of such property taxes shall be submitted from one party to the other prior to the end of the applicable year. The location for tax purposes, at which such crude oil exchange balance is due shall be determined by mutual agreement of the parties.

12. **WINDFALL PROFIT TAX:** The delivering party hereby warrants that any withholding, deposit or payment of Windfall Profit Tax applicable to oil delivered hereunder has been or will be made by a party other than the receiving party. The delivering party agrees to indemnify and hold the receiving party harmless for the full amount of any taxes, penalties or interest which may be required to be paid by the receiving party as a result of reliance upon this warranty. For the purposes of this agreement, the receiving party will not be considered "First Purchaser" of said crude oil for Windfall Profit Tax purposes, and as a result shall not be obligated to withhold or pay any Windfall Profit Tax on receipts hereunder.

13. **TAXES AND FEES, GENERAL:** Liability for all other income taxes, franchise taxes or similar taxes required to maintain the corporate existence, excises, charges, duties, tariffs, and inspection and other fees either now in effect or hereafter imposed by a federal, state or local government, or any governmental agency, authority or subdivision, upon the subject crude oil or operations covered under this Agreement, after title to such crude oil has passed to the receiving party, will be paid by the receiving party. In those cases where either laws or regulations impose upon the party making the delivery the obligation to pay or collect the tax, excise, charge, duty, tariff, inspection or other fees listed above, the party receiving the crude oil shall reimburse the other for such amounts.

14. **FEDERAL CONTRACT CLAUSES:** The attached "Certificate of Nonsegregated Facilities Clause" and the following Executive Orders are incorporated herein by reference. The word "contractor" as used therein shall refer to each party to this contract. Unless exempted by Federal law, rule, regulation, or order, each party shall comply with the provisions of such Certificate or Executive Orders during the performance of this Agreement.

A. Executive Order 11246, as amended, Equal Opportunity;

B. Executive Order 11701, Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era;

C. Executive Order 11758, as amended, Affirmative Action for Handicapped Workers.

15. **ALTERATIONS:** No oral promises, agreements or warranties shall be deemed a part hereof, nor shall any alteration or amendment of this Agreement, or waiver of any of its provisions, be binding upon either party hereto unless the same be in writing, signed by the party charged.

16. **AUDIT:** Each party and its duly authorized representatives shall have access to the accounting records and other documents maintained by the other party which relate to this Agreement and shall have the right to audit such records at any reasonable time or times within three years after the termination of this Agreement.

17. **CONFLICTS OF INTEREST:** No director, employee or agent of either party shall give or receive any commission, fee, rebate, gift or entertainment of significant cost or value in connection with this Agreement. Any representative(s) authorized by either party may audit the applicable records of the other party for the sole purpose of determining whether there has been compliance with this paragraph.

18. **ASSIGNMENT:** This Agreement shall not be assignable by either party without written consent of the other, except that either party may assign this Agreement to any affiliate, provided that any such assignment shall not release the Assignor of any of the obligations hereunder.

19. **WAIVER:** The waiver by either party of the breach of any provision hereof by the other party shall not be deemed to be a waiver of the breach of any other provision or provisions hereof or of any subsequent or continuing breach of such provision or provisions.

20. **SUCCESSORS:** Everything contained herein which binds or affects the parties hereto shall in like manner bind and effect their respective successors and assigns.

21. **GOVERNING LAW:** This Agreement, and any disputes arising hereunder, shall be governed by the laws of the State of California

END OF GENERAL PROVISIONS

CHEVRON U.S.A. INC.
MARINE PROVISIONS
April 1, 1984

As used in these Marine Provisions, "oil" shall mean any crude oil, crude condensate or refined petroleum product as appropriate to the Agreement to which these Marine Provisions are attached.

1. **NOTICE:** The terminal shall be notified by letter or telegram of each vessel nominated under this agreement not less than seven (7) days prior to expected arrival date. The terminal shall be further notified of scheduled arrival date 72, 48, 24 and 6 hours in advance of arrival. After the 6 hour notice, the terminal shall immediately be notified when a scheduled arrival time changes by more than two (2) hours.

   The vessel will be required to send the terminal answers to critical preberthing questions at least 48 hours prior to ETA. The terminal will provide these preberthing questions so as to allow the vessel a reasonable time to respond.

2. **VESSEL CLEARANCE:** At the time the terminal is first notified of vessel, as stated above, the terminal shall have the right to refuse acceptance of such vessel if in terminal's sole opinion such vessel for any reason is unacceptable. The terminal's acceptance or rejection of the nominated vessel shall be communicated to the other party within forty-eight (48) hours after the terminal's receipt of nomination. The terminal's acceptance of any vessel shall not constitute a continuing acceptance of such vessel for any subsequent loading or discharge.

3. **NOTICE OF READINESS:** After the vessel has arrived at the customary anchorage or other place of waiting and is otherwise in all respects ready to proceed to berth and commence loading or discharging oil, the Master or his agent shall tender Notice of Readiness to the terminal by letter, telegraph, wireless, radio telephone, or telephone. Such notice shall not be given until after the vessel has received all port clearances.

4. **VESSEL BERTHS:** The terminal shall provide a berth for the vessel where the vessel can always lie safely afloat (within the specified maximum drafts and the specified minimum water depths) free of all wharfage and dockage dues. All duties and other charges on the vessel, including without limitation those incurred for tugs and pilots, mooring masters, other port costs and tax on services for cargo transfer, shall be borne by the vessel. The terminal shall not be deemed to warrant the safety of any channel, fairway, anchorage or other waterway used in approaching the designated berth. The terminal shall not be liable for any loss, damage, injury or delay to vessel resulting from the use of such waterways not caused by the terminal's fault or neglect.

   All vessels shall be furnished a berth at the terminal in order of their arrival, as determined by receipt of Notice of Readiness. The terminal may require vessel to shift berth from one safe berth to another safe berth. The terminal shall pay all pilot, tug and port expenses incurred in shifting the vessel, and time consumed on account of such shifting shall count as used laytime.

5. **LAYTIME:** Used laytime shall commence six hours after Notice of Readiness has been tendered by vessel, berth or no berth, or when the vessel is all fast (finished mooring), whichever occurs first. If the vessel is to be loaded or discharged at more than one port, the terminal shall be allowed up to six hours following vessel's tender of Notice of Readiness in which to make a berth available at each port before used laytime commences. If the vessel arrives before the first day of the latest accepted arrival date range, Notice of Readiness shall not be effective until 0001 hours local time of the first day of the latest accepted arrival date range, unless the terminal elects to accept the vessel earlier, in which case used laytime shall begin when the vessel is all fast. If the vessel arrives after the last day of the latest accepted arrival date range, used laytime shall not begin until the vessel is all fast.

   The amount of laytime the terminal is allowed to load to or receive from tank ships ("allowed laytime") shall be 36 hours for full cargoes or pro rata thereof for part cargoes. For the purpose of this contract, a full cargo shall be the maximum volume which the vessel can carry at the gravity of oil delivered and at the draft available at the terminal. Time consumed due to any of the following shall not count as used laytime.

   a. Any delay to the vessel in reaching or departing the berth (including weather delays) caused by any reason or condition not reasonably within the terminal's control;

   b. Any time consumed by the vessel in moving from port anchorage to all fast in berth or time consumed by the vessel lining up;

   c. Any delay due to the vessel's condition or breakdown or inability of the vessel's facilities to load or discharge cargo (1) within the laytime allowed or (2) as stated in the information provided for vessel clearance;

   d. Any delay due to prohibition of loading or discharging at any time by the owner or operator of the vessel or by the port authorities unless such prohibition is caused by terminal facility's failure to comply with applicable laws or regulations;

   e. Any delay due to vessel bunkering;

   f. Any delay due to vessel discharging or shifting of ballast, slops or contaminated cargo.

   g. Any delay due to pollution or threat thereof caused by any defect in the vessel or any act or omission to act of the Master or crew of the vessel.

   h. Any delay due to violation by vessel of the operating and/or safety regulations of the terminal, non-compliance with Coast Guard regulations or failure to obtain or maintain an Oil Pollution Responsibility Certificate.

Used laytime shall cease upon disconnection of hoses or cargo arms after all oil has been loaded or discharged. The vessel shall vacate the berth expeditiously consistent with safe operating practices (unless permission to remain is expressly granted by the terminal).

6. **DEMURRAGE:** The party receiving into/delivering from the terminal shall pay demurrage for all time that used laytime exceeds allowed laytime at a rate appropriate to the size and trade of vessel, as specified in the body of this Agreement. Demurrage incurred in port on a temporary basis by reason of fire, explosion, storm or by strike, lockout, stoppage or restraint of labor or by breakdown of machinery or equipment in or about the terminal shall be paid for at one-half the rate otherwise provided for demurrage. The terminal shall not be liable for any demurrage due to delay caused by strike, lockout, stoppage or restraint of labor of Master, officers and crew of the vessel or tugboat or pilots. In the event loading or discharging is terminated prematurely as the result of a force majeure situation, used laytime shall cease at the time the incident causing the termination of the operation commences.

   The principle "once on demurrage always on demurrage" shall not apply. Demurrage claims must be accompanied by such supporting data as the terminal may reasonably request. Such claims must be made and so accompanied within 90 days from the date of the completion of loading or discharge of the cargo in question.

7. **HOSES:** Hoses and steel loading arms shall be furnished by the terminal and shall be connected and disconnected by the terminal, or at the option of the terminal, by the vessel at the terminal's risk and expense.

8. **U.S. COAST GUARD COMPLIANCE:** Vessels shall fully comply (or hold necessary waivers if not in compliance) with all applicable U.S. Coast Guard regulations in effect as of the date vessel berths. Any delay resulting from vessel's non-compliance shall not count as used laytime.

9. **ENVIRONMENTAL COMPLIANCE:** Vessel will comply with all local, State, and Federal environmental laws and regulations while berthed at the terminal. If vessel fails to comply with such laws and regulations, the vessel may be required to leave the terminal. Any vessel delay time caused by the vessel's failure to meet such laws and regulations shall not count as used laytime.

10. **OIL POLLUTION RESPONSIBILITY CERTIFICATE:** Vessels shall comply with the U.S. Federal Water Pollution Control Act, as amended, and shall have secured and carry aboard the vessel a current U.S. Coast Guard Certificate of Financial Responsibility (Water Pollution). Terminal shall not be liable for demurrage or other expenses during any time lost as a result of failure to obtain or maintain the Certificate.

11. **POLLUTION PREVENTION AND RESPONSIBILITY:** (a) In the event an escape or discharge of oil occurs from the vessel and causes or threatens to cause pollution damage, the vessel will promptly take whatever measures are necessary to prevent or mitigate such damage. The vessel hereby authorizes the terminal, or its nominee, at the terminal's option, upon notice to the vessel, to undertake such measures as are reasonably necessary to prevent or mitigate the pollution damage. The terminal or its nominee shall keep the vessel advised of the nature and results of any such measures taken and, if time permits, the nature of the measures intended to be taken. Any of the aforementioned measures shall be at the vessel's expense with the right to deduct the costs thereof from monies payable under this Agreement (except to the extent that such escape or discharge was caused by the terminal), provided that if the vessel considers said measures should be discontinued, the vessel shall so notify the terminal or its nominee and thereafter the terminal or its nominee shall have no right to continue said measures at the vessel's authority or expense. This provision shall be applicable only between the parties and shall not affect any liability of the vessel to third parties, including, but not limited to governments.

    (b) The vessel shall be a participating vessel in Tankers Owners Voluntary Agreement Concerning Liability for Oil Pollution ("TOVALOP"). The owner of the cargo shall be and shall continue to be an Oil Company Party to the Contract Regarding an Interim Supplement to Tanker Liability for Oil Pollution ("CRISTAL").

12. **WHARF DAMAGE:** Vessel assumes full responsibility for any damage sustained by wharves, berths, or docks owned or maintained by terminal arising out of the negligent or improper operation of tows, barges, or any other waterborne craft, either owned or operated by vessel or being operated by Subcontractors of vessel. Vessel shall fully and completely indemnify terminal for any such damages.

13. **CRUDE OIL WASHING:** The Master of the vessel shall request the terminal's permission at least 48 hours before arrival if the vessel intends to carry out Crude Oil Washing in port and shall comply with any terminal guidelines on Crude Oil Washing.

14. **INERT GAS SYSTEM:** The vessel shall comply with any terminal guidelines on Inert Gas Systems. All vessels equipped with an Inert Gas System shall keep the system operable at all times during berthing, while at berth and during unberthing. The Master of the vessel shall provide the terminal with a signed declaration that the vessel's Inert Gas System is operational and that the cargo and slop tanks are inerted. The Master of the vessel shall immediately notify the terminal if the Inert Gas System becomes inoperable or if the vessel is unable to maintain a positive pressure and/or an oxygen content at or below eight percent by volume in the cargo and slop tanks.

END OF MARINE PROVISIONS

HB 559

BILL SHEFFIELD, GOVERNOR

REPLY TO:

☑ 1031 W 4th AVENUE
SUITE 200
ANCHORAGE, ALASKA 99501
PHONE: (907) 276-3550

☐ 1st NATIONAL CENTER
100 CUSHMAN ST.
SUITE 400
FAIRBANKS, ALASKA 99701
PHONE: (907) 452-1568

☐ POUCH K - STATE CAPITOL
JUNEAU, ALASKA 99811
PHONE: (907) 465-3600

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

January 14, 1986

The Honorable Ben F. Grussendorf
Speaker of the House of Representatives
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Reference: "An Act Relating to the Sale and Purchase of Royalty Oil from the Kuparuk Unit between the State of Alaska and Petro Star, Inc. and Chevron U.S.A. Inc.

Dear Mr. Speaker:

In accordance with AS 38.06.040(a)(3), I am forwarding for your consideration the resolution of the Alaska Royalty Oil and Gas Development Advisory Board which recommends that the legislature approve the referenced sale of royalty oil to Petro Star and Chevron U.S.A.

If we can be of further service, please do not hesitate to call.

Sincerely,

HAROLD M. BROWN
ATTORNEY GENERAL

By: Stan R Porter for
Ann E. Prezyna
Assistant Attorney General

AEP/ma

03-C5LH

RECEIVED
Department of Law
JAN - 3 1986
Office of the Attorney General
Anchorage Branch
Anchorage, Alaska

7H-559

The Alaska Royalty Oil and Gas Development Advisory Board

Resolution 85-2

On or about October 23, 1985, the director of the division of oil and gas ("director") provided the Alaska Royalty Oil and Gas Development Advisory Board with the preliminary notice of sale, preliminary findings, and proposed contract for a long-term sale of up to about 6500 barrels per day of Kuparuk River Unit royalty oil to Petrostar, Inc. and Chevron U.S.A. Inc.

This proposed sale has been discussed at several public meetings held by the board during 1985. At the February 20 meeting, Petrostar representatives testified in support of a royalty oil sale. On March 26, staff of the Alaska Department of Natural Resources (DNR) reported to the board on the status of a solicitation for purchasers of state royalty oil. At the April 12 meeting, DNR presented a status report on the solicitation, which was released April 1. On July 25, DNR presented to the board a recapitulation of the responses to the solicitation. At the meetings of the board held September 26-27 and October 7, the board received public testimony on a proposed sale of Kuparuk royalty oil to Petrostar and Chevron. On October 30, the director made a presentation to the board on the Petrostar-Chevron contract proposed in DNR's October 23 preliminary findings; the board also received public testimony on the proposed contract. The last two meetings were held by teleconference in Anchorage, Fairbanks, Valdez, and Juneau.

DNR's final findings on the proposed sale and the contract were sent to the board on December 9, 1985. On December 19, the board met to develop and vote on its recommendations to the legislature on the proposed sale.

Based on the board's review of the agreement for the sale and purchase of royalty oil between the State of Alaska and Petrostar and Chevron, DNR's findings and determinations regarding the proposed sale, and the testimony received at public meetings of the board, the board is of the opinion that the proposed disposition of Kuparuk River Unit royalty oil to Petrostar and Chevron meets the requirements of AS 38.06 and 3 AAC 56. The board recommends that the Fifteenth Alaska Legislature approve the agreement for the sale and purchase of royalty oil from the Kuparuk River Unit to Petrostar and Chevron, dated December 9, 1985.

Dated: December 19, 1985

Laurie S. Cunningham

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF LAW

POUCH K – STATE CAPITOL
JUNEAU, ALASKA 99811
PHONE: (907) 465-3600

OFFICE OF THE ATTORNEY GENERAL

January 22, 1986

M E M O R A N D U M

TO: Honorable Bill Sheffield
Governor

Harold M. Brown

FROM: Harold M. Brown
Attorney General

RE: Attached bill on Petro Star/
Chevron royalty oil contract
Our file: 377-094-86

Attached is a bill (prepared for both House and Senate introduction), requested by the Department of Natural Resources (DNR), which provides for legislative approval and ratification of a royalty oil contract between the state and both Petro Star Inc. and Chevron U.S.A. Inc. for the sale of Kuparuk River royalty oil. This contract is the result of negotiations with the companies over the past year. If you prefer not to introduce this bill in both houses, DNR would prefer that it be introduced in the Senate.

Also attached are copies of the resolution of the Alaska Royalty Oil and Gas Development Advisory Board recommending that the legislature approve this sale of royalty oil. These copies are attached to original letters forwarding the Royalty Board's resolution to the Speaker of the House and the President of the Senate. In accordance with AS 38.06.040(a)(3) and AS 38.06.070(c), this resolution and the appropriate letter should be transmitted with each bill at the time of introduction.

If you only introduce the bill in the Senate, it should not be necessary to send the separate Department of Law letter and copy of the board's resolution to the Speaker of the House. However, it might be wise to do so as a courtesy.

A draft transmittal letter, explaining the bill in more detail, is also attached.

HMB:SRP:ma

cc w/enc.: Hon. Esther Wunnicke, Commissioner
Department of Natural Resources

03 – C32LH

BILL SHEFFIELD
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

The Honorable Ben Grussendorf
Speaker of the House
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Representative Grussendorf:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill that provides for legislative approval of a royalty oil contract between the state, Petro Star, Inc. and Chevron U.S.A., Inc. for the sale of Kuparuk River royalty oil. Also transmitted with this bill is a copy of the resolution of the Alaska Royalty Oil and Gas Development Advisory Board recommending approval of that contract, along with a letter from the Department of Law forwarding the resolution to you. This resolution is being transmitted in accordance with AS 38.06.040(a)(3) and AS 38.06.070(c).

The contract is also described in the findings issued by the Department of Natural Resources on December 9, 1985. Copies of these findings have been made available to the legislature and the public for review.

A bill approving the contract is being introduced for legislative approval for two reasons. First, as a matter of comity, I respect the legislature's desire to have a direct voice in major disposals of royalty oil. Therefore, although this and the previous administration have consistently taken the position that the statutory requirement of legislative approval of royalty oil contracts (AS 38.06.055) is unconstitutional, the contract itself contains provisions requiring approval by the legislature before it takes effect.

Second, this legislation would ratify the royalty oil contract. This ratification would cure any procedural defect that may have occurred in the process of entering into this contract. Although we believe that all necessary steps have been taken, the statutes and regulations governing the disposal of royalty oil represent often-conflicting desires and goals -- both procedural and substantive. For example, the statutes provide that the legislature is to approve a royalty oil contract only by "enacting legislation" (AS 38.06.055(a)), but also refer to a Royalty Board recommendation to be submitted to the legislature at the time a "resolution approving the proposed sale ... is introduced in the legislature" (AS 38.06.070(c)). Since legislative approval by enactment of legislation is required as a matter of contract, I believe that it is prudent to present this contract for legislative approval and ratification.

Sincerely,

Bill Sheffield
Governor

COMMITTEE REPORT

SENATE

FURTHER: FINANCE

4/3/86

Date 4/4/86

Mr. President

The Committee on RESOURCES considered HB 559

approving the sale of Kuparuk River Unit royalty oil by the State of Alaska to Petro Star, Inc. and Chevron U.S.A.., Inc; efd.

and (a majority of the committee) (the committee) reports it back with the following recommendations:

[X] do pass

[ ] do pass with attached amendment(s)

[ ] replace with/or adopt CS for ______
[ ] new title
[ ] same title and recommends ______

[ ] and attached a "LETTER OF INTENT" [ ] NEW FISCAL NOTE

[ ] reports it back without recommendation

[ ] recommends referral to ______ Committee

MEMBERS SIGNING DO PASS	MEMBERS HAVING OTHER RECOMMENDATIONS
[signature]	Rick Halford NO REC
[signature]	
[signature]	
Fred F. Zharoff	

[signature]
Chairman

Do Pass
Chairman recommendation

BILL SHEFFIELD, GOVERNOR

OFFICE OF THE GOVERNOR

OFFICE OF MANAGEMENT AND BUDGET
DIVISION OF STRATEGIC PLANNING

POUCH AD
JUNEAU, ALASKA 99811
PHONE: (907) 465-3568

February 3, 1986

The Honorable Sam Cotten
Representative
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Representative Cotten:

Please find enclosed our analysis of your proposed changes to the Economic Limit Factor.

Sincerely,

Gordon S. Harrison

Gordon S. Harrison
Associate Director

GSH/TC/dmc

Enclosure

cc: Jim Ayers, Director
Legislative Relations
Office of the Governor

01 A34LH

February 2, 1986

THE PETROLEUM SEVERANCE TAX IN ALASKA: MODIFICATION OF THE ECONOMIC LIMIT FACTOR

Prepared by: Thomas Chester
Office of Management and Budget

Severance Tax

Alaska's petroleum severance tax is set by law at 15 percent[1] of the gross value of production, but this percentage is adjusted downward on the basis of the average productivity of the wells in a field. Only fields with extremely productive wells would pay the full 15 percent.

The Prudhoe Bay field now pays the full nominal severance tax rate of 15 percent, but only because of a special statutory provision that will expire in 1987 (FY '88[2]). At that time, the severance tax on Prudhoe Bay will begin to be adjusted downward in relationship to the declining average productivity of the wells in the field.

The formula for the downward adjustment of the nominal severance tax rate is called the economic limit factor (ELF). It is intended to encourage the maximum total production of an oil field by progressively lowering its effective severance tax as the field goes into decline.

ELF

Each field has its own ELF, which is computed monthly as a function of average daily output per well. Figure 1 shows this relationship. Fields with higher daily output have a higher ELF, and thus pay more tax. Figure 1 also indicates the forecasted FY 88 average daily production of three North Slope fields and their associated ELFs.

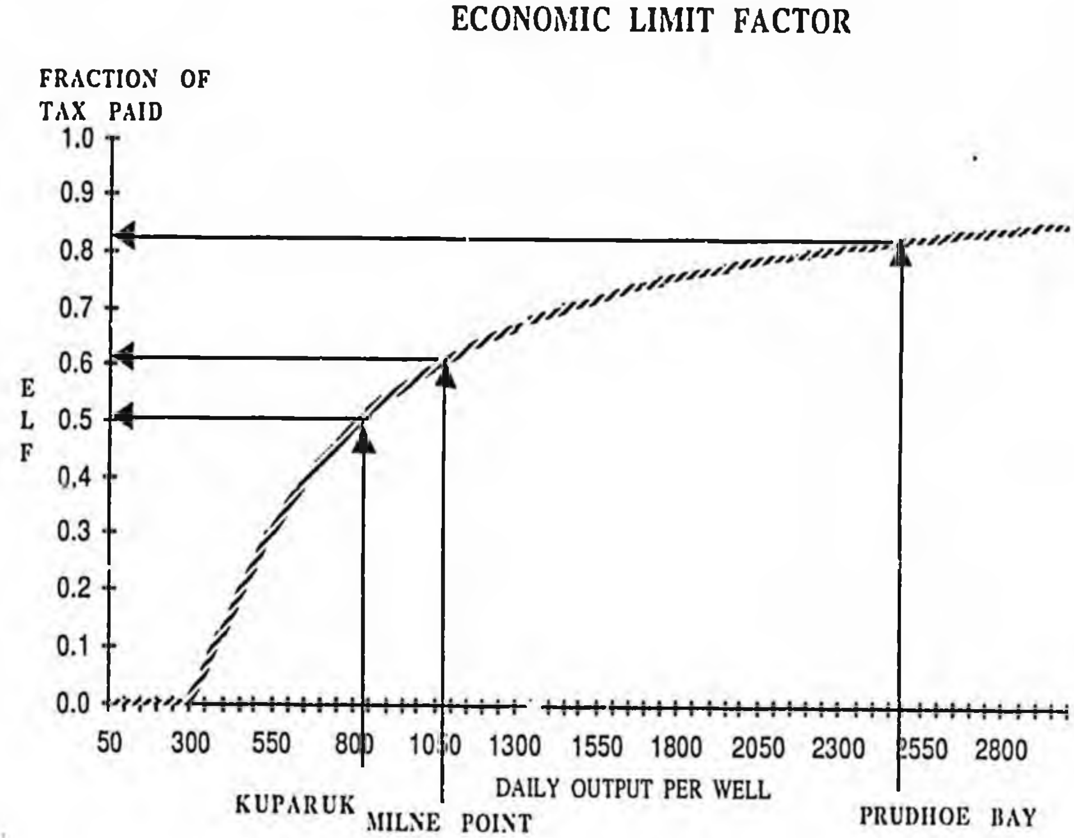

Figure 1

The actual severance tax rate paid (the effective severance tax rate) is equal to the ELF (which is always between 0 and 100 percent) multiplied by the statutory tax rate (usually 15%) . This produces the effective severance tax rates shown in Table 1 below.

Table 1

Effective Severance Tax Rates

North Slope Fields - FY 88, under current ELF

Field	ELF	X	Nominal Rate	=	Effective Rate
Prudhoe Bay	.82		15%		12.3%
Kuparuk	.52		15%		7.5%
Milne Point	.60		15%		9.0%

Modification of the ELF formula

The existing ELF formula is based on average daily well productivity and does not take account of the average daily production of the entire field. That is why the Prudhoe Bay and Kuparuk fields begin to enjoy the severance tax reduction even though they are among the most productive fields in the western hemisphere. Also, because the existing ELF formula fails to account for average daily field production, the Milne Point field will have a comparatively high ELF even though it is a very small and economically marginal field on the north slope.

A modification of the ELF formula that incorporates overall field production characteristics could increase the effective severance tax rate on large, productive fields such as Prudhoe Bay and Kuparuk, and reduce the effective tax rate on the small, marginal fields that most need the economic benefits of the lower tax burden.

At the request of Rep. Cotten, OMB has evaluated the effects of one such modification.[3] Table 2 shows the change in the effective tax rate for several oil fields. Table 3 shows the revenue implications of those changes.

Modification of the ELF formula to include total field productivity would improve the chances of a small, marginal field being brought into commercial production. These fields may have good well productivity characteristics but high costs because of the inability to spread fixed costs over a large number of producing wells (as in the case of Prudhoe Bay and Kuparuk).

Table 2

COMPARISON OF ELF'S

FY 89

	Existing ELF	Modified ELF	% change
Prudhoe Bay	.80	.99	+23%
Kuparuk	.50	.86	+72%
Milne	.60	.31	-48%
Endicott	.31	.0	-100%
Lisburne	.11	.05	-54%
West Sak	.0	.0	no change
Cook Inlet	.03	.0	100%

Table 3
Revenue Impact
from ELF, FY 87 - 94
Millions of $

Year	Revenue Loss From Current ELF	Revenue Gain From Proposed ELF
87	70	68
88	234	183
89	263	185
90	243	180
91	241	172
92	324	169
93	332	166
94	340	155

FOOTNOTES

[1]For any lease or property coming into commercial oil production after June 30, 1981, the severance tax rate is 12.25% during the first 5 years of production and 15% after that. (AS 43.55.011)

[2]This special statutory provision applies to all fields.

[3]

EXISTING ELF

$$ELF = (1 - PEL/TP)^{(460*WD/PEL)}$$

POSSIBLE ALTERNATIVE

$$ELF = (1 - PEL/TP)^{(37,000,000/(PEL*TP/Days))}$$

Where:

- PEL is production at the economic limit and in statute is set at 300 barrels per day per well
- TP is total production for the field
- WD is well days
- 460 and 37,000,000 are constants

STATE OF ALASKA

BILL SHEFFIELD, GOVERNOR

OFFICE OF THE GOVERNOR

OFFICE OF MANAGEMENT AND BUDGET

DIVISION OF STRATEGIC PLANNING

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February 3, 1986

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Associate Director

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Enclosure

cc: Jim Ayers, Director
Legislative Relations
Office of the Governor

February 2, 1986

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Prepared by: Thomas Chester
Office of Management and Budget

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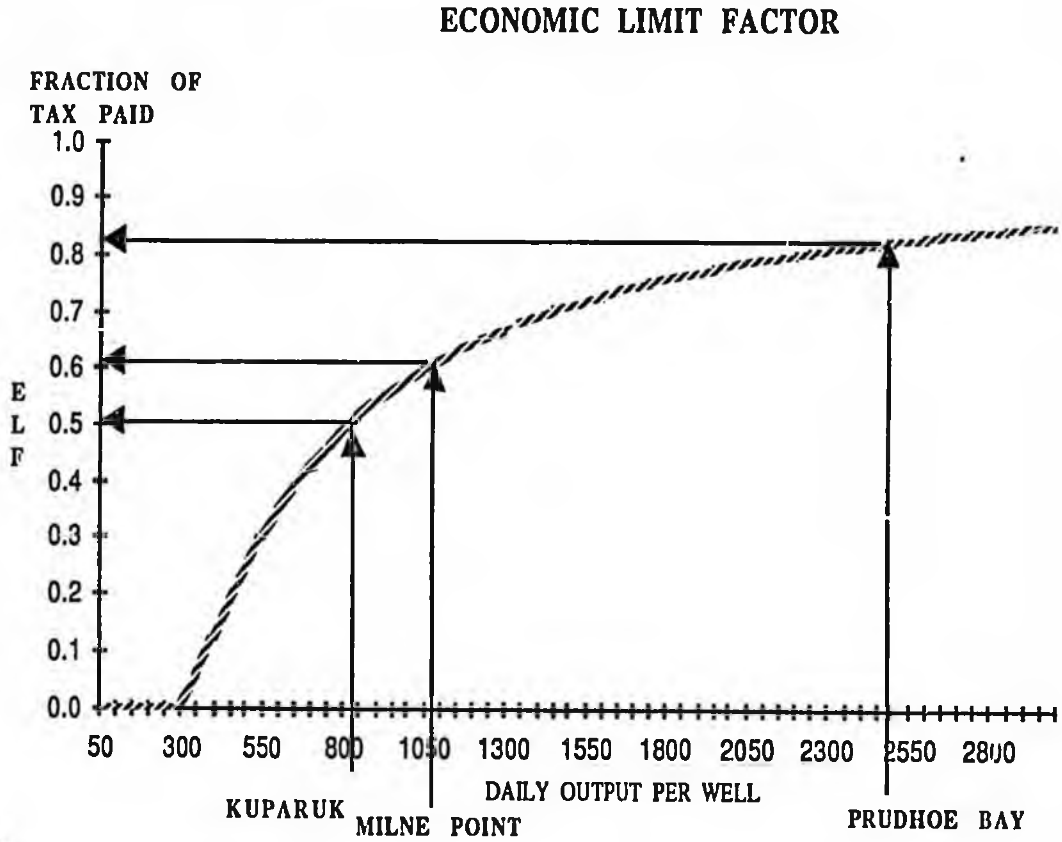

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A modification of the ELF formula that incorporates overall field production characteristics could increase the effective severance tax rate on large, productive fields such as Prudhoe Bay and Kuparuk, and reduce the effective tax rate on the small, marginal fields that most need the economic bene..its of the lower tax burden.

At the request of Rep. Cotten, OMB has evaluated the effects of one such modification.[3] Table 2 shows the change in the effective tax rate for several oil fields. Table 3 shows the revenue implications of those changes.

Modification of the ELF formula to include total field productivity would improve the chances of a small, marginal field being brought into commercial production. These fields may have good well productivity characteristics but high costs because of the inability to spread fixed costs over a large number of producing wells (as in the case of Prudhoe Bay and Kuparuk).

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3

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Where:

•PEL is production at the economic limit and in statute is set at 300 barrels per day per well
•TP is total production for the field
•WD is well days
•460 and 37,000,000 are constants

MEMOR NDUM *Division of Strategic Planning*

TO: Representative Sam Cotten DATE: January 15, 1986
FROM: Thomas P. Chester
RE: Computation of the Economic Limit Factor

In response to your request the following provides the information needed to compute the Economic Limit Factor (current and as you propose), a numerical example, and a chart which displays the effect of field size on the value of the proposed Economic Limit Factor (ELF).

The current and proposed Economic Limit Factor formulas are:

$$\text{Current ELF} = (1 - PEL/TP)^{((460*WD)/PEL)}$$
$$\text{Proposed ELF} = (1 - PEL/TP)^{((37{,}000{,}000*WD)/(PEL*TP/Days))}$$

The following definitions are used in computing ELF values:

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 * 541 wells * 30 days = 4,869,000 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:

541 wells * 30 days * 2477 barrels per well = 40,201,710 barrels of production per month

WD (Well Days) =
(average number of operating wells during the month)*
(number of days of production for the month). For example:

541 wells * 30 days = 16,230 well days

TP/Days =
(average number of operating wells during the month)*
(average daily production per well). For example:

541 wells * 2477 barrels per well = 1,340,057 barrels of production per day

Table 1.
Hypothetical ELF
Under Current and Proposed Law Using
Values Given In Examples Above

Current ELF

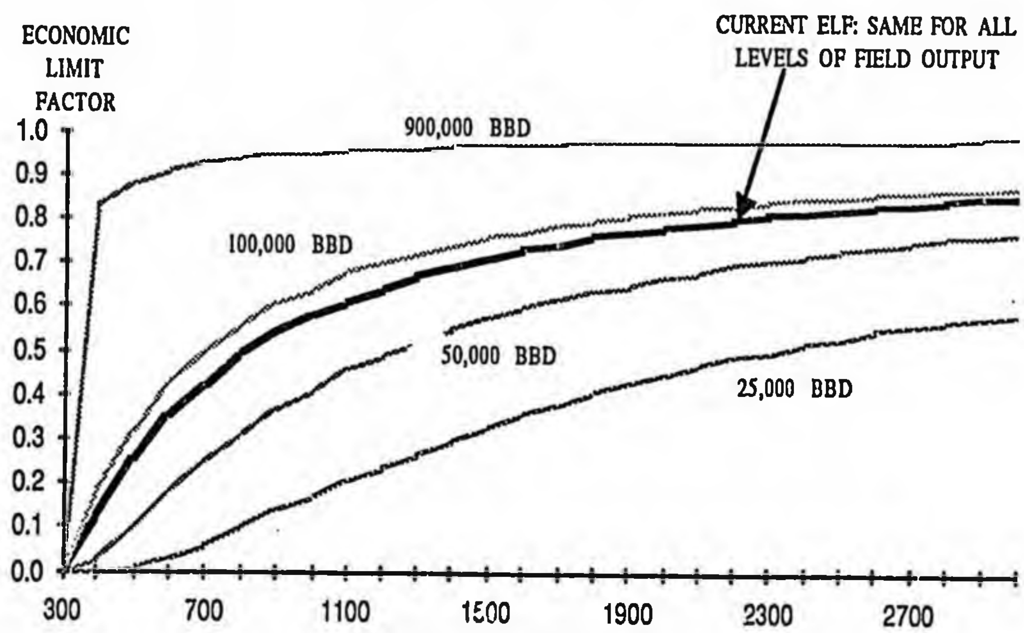
$$(1 - 4{,}869{,}000/40{,}201{,}710)^{(460*16{,}230/4{,}869{,}000)} = .82$$

Proposed ELF

$$(1- 4{,}869{,}000/40{,}201{,}710)^{(37{,}000{,}000*16{,}230/(4{,}869{,}000*1{,}340{,}057)} = .99$$

chart 1

THE ECONOMIC LIMIT FACTOR (ELF):
CURRENT AND PROPOSED FOR VARIOUS LEVELS OF
WELL OUTPUT AND FIELD PRODUCTION



NOTE: BBD FIGURES REPRESENT DAILY FIELD PRODUCTION IN BARRELS PER DAY

When the formulas are written out incorporating the definitions given above they become unwieldy. For the curious they are:

Current ELF (Economic Limit Factor)[1] = $(1 - PEL/TP)^{((460*WD)/PEL)}$

= (1 - {(300 barrels per day)*(average number of operating wells during the month)*(number of days of production for the month)}/ {(average number of operating wells during the month)*(number of days of production for the month)*(average daily production per well)})$^{\text{(460*(average number of operating wells during the month)*(number of days of production for the month)/\{(300 barrels per day)*(average number of operating wells during the month)*(number of days of production for the month))}}$

Proposed ELF[2] = $(1 - PEL/TP)^{((37{,}000{,}000*WD)/(PEL*TP/Days))}$

= (1 - {(300 barrels per day)*(average number of operating wells during the month)*(number of days of production for the month)}/ {(average number of operating wells during the month)*(number of days of production for the month)*(average daily production per well)})$^{\text{(37,000,000 * (average number of operating wells during the month)*(number of days of production for the month))/((300 barrels per day)*(average number of operating wells during the month)* (number of days of production for the month) * (average number of operating wells during the month)*(average daily production per well))}}$

---

[1]The formula for the existing ELF can be simplified through cancellation of like terms in the numerator and denominators of the various formula terms. Consider: PEL/TP = (300 * days * wells)/(days * wells * well_prod) = 300/well_prod and (460 * wells * days)/(300 * wells * days) = 460/300 = 1.533.
Making these substitutions into the ELF formula gives:

$$ELF = (1 - 300/well\_prod)^{1.533}$$

[2]The formula for the proposed ELF can be simplified through cancellation of like terms in the numerator and denominators of the various terms. consider:
PEL/TP = (300 * days * wells)/(days * wells * well_prod) = 300/well_prod and (37,000,000 * wells * days)/(300 * wells * wells * well_prod) = 37,000,000/(300 * wells * well_prod) = 37,000,000/(300 * total field production).
Making these substitutions into the proposed ELF formula gives:

$$ELF = (1 - 300/well\_prod)^{123{,}333/TP/Days}$$

from Cotten Repor

III.

THE SEVERANCE TAX AND THE ECONOMIC LIMIT FACTOR

I. Introduction

It is generally known that oil producers in Alaska are assessed severance tax rates of 12.25 or 15 percent. However, it may not be so well known that the actual tax rates they pay are much lower than this because of the economic limit factor or ELF. (A severance tax or production tax is a flat tax based solely on the amount produced; in contrast, an income tax is based on profits.)

The ELF is a statutory reduction to the severance tax. It was adopted in 1977[1] to promote production on oil and gas fields with low output and presumably little profit. As the cost of producing the oil gets closer to its value -- the economic limit -- the ELF reduces the tax that is owed. When a field reaches the economic limit the ELF reduces the severance tax to 0. The ELF is applied to both oil and gas, but this discussion deals only with oil.

In practical terms, the ELF dramatically reduces the state's base severance tax rates of 12.25% or 15% on all fields. Prudhoe Bay is a temporary exception to this

---

[1]In anticipation of North Slope production, the Department of Revenue recommended the ELF in its exhaustive 1977 study: "Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement." Previously a "stair-step" approach to severance taxes was used, keyed to Cook Inlet production, with graduated rates to 8 percent. The ELF improved upon the stair steps, retaining the idea that the tax should be reduced as production declined. The ELF also was able to adjust tax rates for both high-volume North Slope fields and the lower-volume Cook Inlet fields.

because of a provision that suspends the ELF for 10 years on high volume fields. However, in FY 88 the 10-year limit expires and Prudhoe will also enjoy tax concessions of the ELF -- and the state will lose $156 million, according to OMB calculations (see Attachment A). Another example is Kuparuk. In FY 86 the ELF reduced Kuparuk's effective severance tax rate to 6%, and the state lost $58 million.

An unforeseen consequence of the ELF is that it will greatly reduce the severance tax rates on most of the fields that have yet to begin producing. For example, in FY 90 the effective severance tax rate for Lisburne will be 3% and for Endicott it will be 4%. These cases show that the ELF is actually providing these marginal fields with a substantial incentive -- reducing costs at field start-up.

The ELF's original goal was to extend the life of fields, and thus extend revenues to the state. However, one study shows that the ELF only prolongs a field's life for one or two years, thus its direct benefit to the state is limited. Nonetheless, the ELF does appear to provide an incentive to developers of marginal fields because it reduces the severance tax rate. If the ELF were eliminated, for example, it is likely that some of the marginal fields would not be feasible to develop.[2]

---

[2] In a study entitled "Alaska North Slope Oil Production and Revenue Projections" published Feb. 1985 by the Institute of Social and Economic Research, author and UAA economist Matthew Berman concluded that the Endicott and Milne Point fields might not be feasible to develop without the ELF.

It's also apparent that fields with substantial output and correspondingly high profit rates, such as Prudhoe and Kuparuk, do not require the production incentive that the ELF provides.

II. How the ELF Works

The ELF is a formula that is multiplied by the nominal rate of 12.25% or 15% to obtain the effective rate actually applied to a field. The ELF will never be more than 1. If the ELF is 1, then 100% of the severance tax is owed. An ELF of .8 means 80% of the tax is owed; 80% of 15% equals an effective tax rate of 12%.

Since 1981 the severance tax rate has been 15%, with an exception for new fields; fields that start producing after June 30, 1981 pay a reduced rate of 12.25% for the first five years. The law also requires that the ELF be calculated at 1 during the first 10 years of a field's production any time the ELF goes above .7. (Currently this provision only affects Prudhoe.) For fields with an ELF at or below .7, the actual ELF used. After 10 years the actual ELF is used in all cases.

For example, the ELF for Prudhoe Bay in FY 85 was .864 Since this is more than .7 and within the first 10 years of production, the 1 figure is used. Thus the full 15% severance tax was owed.

In FY 88, however, the 10-year limit will no longer be in effect for Prudhoe (production began in FY 78) and the actual ELF of .82 will be used. This means the amount of severance tax owed will be 82% of 15%, or an effective rate of 12.5%. The amount to be paid to the state will be $714 million, $156 million less than if the full 15% severance tax were paid.

III. Modifying the ELF

It is apparent that the ELF accomplishes its goals but not without some drawbacks. One drawback is providing and unnecessary tax reduction for Prudhoe and Kuparuk. Another issue is whether it goes far enough in reducing the severance tax rate on marginal fields. (A problem with a severance tax as opposed to an income tax is that it is not sensitive to profits or costs, thus a fair tax rate for a large field may be a burden for a small field.)

An additional problem with the current ELF formula is that it is based on daily output per well; total field production is not taken into account. This penalizes a marginal field like Milne Point (30,000 bbls/day) which has high output per well but few wells (about 22). Under the current ELF formula Milne is subject to a severance tax rate almost as high as the tax applied to Kuparuk (240,000 bbls/day), which is clearly not a marginal field. For example, in FY 88, Milne Point will be paying a 7.35% severance tax compared to Kuparuk's rate of 7.6%.

Instead of basing the ELF on individual wells, total field production could be included in the ELF formula to compensate for this inequity, keeping the severance tax low on the smaller fields that would benefit most from a tax break.

The ELF could be modified to accomplish these goals:

-- Dramatically reduce the effective severance tax rates for all marginal fields, including Cook Inlet.

-- Prevent a premature reduction to the severance tax rates for Prudhoe and Kuparuk. These highly profitable fields are years away from being marginal. When they do start approaching the economic limit, the ELF formula will provide them with a tax break.

-- More equitably set the tax rate for each field.

This formula modification would bring Prudhoe's ELF to .99 (now it is at .83); raise Kuparuk's to .8 and drop Milne Point's to .3. These ELFs translate into effective severance tax rates of about 14.85%, 12% and 4.5%.

Here are the current ELFs compared with ELFs under the revised formula.

	Current ELF	Modified ELF	% change
Prudhoe Bay	.80	.99	+23
Kuparuk	.50	.86	+72
Milne Point	.60	.31	-48
Endicott	.31	.0	-100
Lisburne	.11	.05	-54
West Sak	.0	.0	no change
Cook Inlet	.03	.0	-100

The formula change would result in the following positive state severance tax collections*:

FY	millions
87	$ 32
88	179
89	192
90	184
91	175
92	173
93	170
94	158

* These numbers, based on June 1985 revenue projections, assume the actual ELF is used in all cases and assume a 15% severance tax rate across the board. (If the 12.25% for the first 5 years were retained, there would be little change in these amounts.)

IV. What Legislation Would Require

1) Simplify the law so the actual ELF is always applied. Current law requires that an ELF of 1 be used if the actual ELF goes above .7 any time during the first 10 years of a field's production. (AS 43.55.013)

2) Change the ELF formula. (AS 43.55.013) This modification only alters the exponent part of the formula. It uses a different number as a constant and takes into account average daily production from the whole field.

Current ELF formula:

$$ELF = \left(1 - \frac{PEL}{TP}\right) \exp \left(\frac{460xWD}{PEL}\right)$$

Revised ELF formula:

$$ELF = \left(1 - \frac{PEL}{TP}\right) \exp \left(\frac{37{,}000{,}000xWD}{PELxTP/Days}\right)$$

PEL = monthly production rate at the economic limit (300 barrels x number of well days a month)
TP = total production (number of barrels) during the month
WD = well days in the month
exp = the expression following this is an exponent
Days = The number of days in the month for which the tax is to be paid

The numbers 460 and 37,000,000 are constants or scaling factors.

V. Conclusion

Enacting these changes to the severance tax would not only maintain our current level of severance tax revenue. More importantly, the revised ELF would provide a new

Attachment 7

ALASKA NORTH SLOPE OIL AND GAS REVENUES

Alaska North Slope Oil Revenue

	Fiscal Years									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
June 1985 Pet. Rev. Assumptions										
World Oil Price	26.37	24.01	22.41	22.206	22.733	23.464	24.362	25.565	26.934	28.379
Average Rate of Inflation	4.03	3.92	4.01	4.76	4.76	4.76	4.76	4.76	5.184	5.184
ANS/World Qual.& Marketing Adjust	3.253	2.532	2.663	2.639	2.386	2.447	2.475	2.528	2.587	2.612
TransAlaska Pipeline Tariff	6.007	6.007	6.007	6.007	6.007	6.007	6.007	6.007	6.007	6.007
ANS Netback Price P801 ($/bbl)	17.11	15.471	13.74	13.56	14.34	15.01	15.88	17.03	18.34	19.76
Prudhoe Bay Prod.(MMbbl/d)	1.528	1.517	1.508	1.34	1.188	1.083	.874	.815	.753	.641
Prudhoe Bay Price ($/bbl)	17.11	15.471	13.74	13.56	14.34	15.01	15.88	17.03	18.34	19.76
Wells	460.25	509.6	527.1	540.6	524.85	505.15	489.9	466.45	447.65	420.65
ELF	.8640307	.8496946	.8437062	.8285288	.8041141	.7838653	.7548433	.7491265	.7399281	.7145822
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.15	.15	.15	.1230793	.1206171	.1175198	.1131865	.1123698	.1109892	.1071793
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	1252.465	1124.336	992.6137	714.2504	656.2593	580.2696	501.3609	490.1035	409.5263	433.5515
SEVERANCE TAX (NO ELF)	1252.465	1124.336	992.6137	870.4757	816.1270	740.6450	664.8966	664.9124	561.5863	606.7802
CONSERVATION TAX	.6100063	.6056148	.6020219	.5349531	.4742719	.4111953	.3489172	.3253633	.3006117	.2558792
Gathering & Cleaning Charge	.7	.72021	.7567558	.7871817	.8245678	.8638172	.9049149	.9488898	.9931351	1.044619
ROYALTIES	1144.023	1028.395	893.2797	788.9031	732.5797	664.7822	597.1494	597.9988	595.9624	547.3418
TOTAL OIL PROD REVENUES	2396.488	2144.731	1885.893	1495.153	1380.829	1245.052	1090.518	1096.182	1085.489	980.8945
Kuparuk River Prod.(MMbbl/d)	.167	.2	.219	.239	.239	.239	.21	.187	.162	.143
Kuparuk River Price ($/bbl)	16.29	14.651	12.92	12.74	13.52	14.19	15.06	16.21	17.52	18.94
Wells	154.5	248.5	284	285.25	285.25	285.25	276.5	276.5	254	254
ELF	.69	.4891136	.4697785	.5067938	.5067938	.5067938	.4627634	.4070192	.3773622	.3112742
Nominal Tax Rate	.1225	.1225	.1363	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.084525	.0599164	.0640297	.0760191	.0760191	.0760191	.0694145	.0610529	.0566043	.0466911
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	73.43848	56.87173	57.86143	73.92498	78.45892	82.33865	78.11249	59.18682	51.30973	48.38798
SEVERANCE TAX (NO ELF)	106.4326	114.6395	123.1696	145.8678	154.7985	162.4697	151.5083	145.2168	135.9694	129.7582
CONSERVATION TAX	.0666695	.0798438	.0874289	.0954133	.0954133	.0954133	.0838359	.0748539	.0646734	.0578883
Gathering & Cleaning Charge	.4	.4005	.4010006	.4015019	.4020038	.4025063	.4030094	.4035132	.4040175	.4045226
ROYALTIES	121.8719	130.0358	125.8883	134.5436	143.8436	150.3448	148.4323	134.8598	126.5085	120.9324
TOTAL OIL PROD REVENUES	194.5103	186.1075	182.9497	208.4685	221.4945	232.6827	218.5148	193.9658	177.0182	161.3283
Milne Point Prod.(MMbbl/d)	0	0	.008	.023	.023	.023	.023	.023	.018	.016
Milne Point Price ($/bbl)	17.48	15.841	14.11	13.93	14.71	15.38	16.25	17.4	18.71	20.13
Wells	1	1	21.15	21.15	21.15	21.15	21.15	19.6	17.1	15.6
ELF	0	0	.8092001	.6096111	.6096111	.6096111	.6096111	.6159828	.5978649	.5882759
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	0	0	.0133928	.0914417	.0914417	.0914417	.0914417	.0951853	.0896797	.0882414
Royalty Percentage	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625
SEVERANCE TAX (ELF)	0	0	.4621848	8.955726	9.457195	9.887944	10.44728	11.66987	9.232479	8.687879
SEVERANCE TAX (NO ELF)	0	0	5.175981	14.69888	15.51349	16.22888	17.13761	18.35842	15.44242	14.76837

incentive for future oil exploration and production in Alaska by lowering the severance tax on marginal fields.

[illegible]										
SEVERANCE TAX (ELF)	0	0	0	0	0	0	0	0	0	0
SEVERANCE TAX (NO ELF)	0	0	0	0	0	0	0	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	0	0	0	0	0	0	0
TOTAL OIL PROD REVENUES	0	0	0	0	0	0	0	0	0	0

NORTH SLOPE Prod. (MMbbl/d)	1.695	1.717	1.744	1.66	1.584	1.48	1.33	1.257	1.17	1.031
AVG. NORTH SLOPE PRICE ($/bbl)	17.02921	15.37540	13.63733	13.40789	14.13640	14.74674	15.57237	16.70890	18.00509	19.39853
AVG. NOMINAL TAX RATE	.1472906	.1467967	.1401377	.1460136	.1428015	.1450169	.1469192	.1465652	.1462150	.1475727
AVG. EFFECTIVE TAX RATE	.1435491	.1395069	.1370937	.1115651	.1036098	.0986205	.0934909	.0912105	.0092272	.0830136
AVG. ROYALTY PERCENTAGE	.125	.125	.1251720	.1257348	.1262922	.1264084	.1265956	.1267101	.1267017	.1266031
SEVERANCE TAX	1325.903	1180.408	1050.937	797.1311	746.6525	693.3015	623.8119	617.2010	605.4633	540.1976
CONSERVATION TAX	.6766758	.6054586	.6961006	.6621466	.6314206	.5090927	.5299927	.5000326	.4661775	.4100404
ROYALTIES	1245.095	1150.430	1030.594	968.9079	982.9065	961.0279	916.9057	932.5029	936.9096	890.0760
TOTAL OIL PROD REVENUES	2591.675	2331.524	2082.220	1766.701	1730.190	1655.799	1541.240	1550.366	1542.839	1431.404
	14.35491	13.95069	13.70037	11.15651	10.36098	9.862054	9.349086	9.121849	8.922717	8.301360

FISCAL IMPACT OF ELF REPEAL ON SEVERANCE TAX INCOME

ALL NORTH SLOPE FIELDS

	FY85	86	87	88	89	90	91	92	93	94
SEVERANCE TAX (MILLIONS OF $)										
NO ELF	1358.897	1238.976	1125.702	1039.874	1023.750	1011.850	971.7980	983.0472	983.7061	941.9287
WITH ELF	1325.903	1180.400	1050.937	797.1311	746.6525	693.3815	623.8119	617.2010	605.4633	540.1976
REVENUES RESULTING FROM										
REPEAL OF ELF	32.99410	58.56776	74.76486	242.7425	277.0974	318.4690	347.9870	365.7653	378.2428	401.7311
CUMULATIVE TOTAL	32.99410	91.56186	166.3267	409.0693	686.1667	1004.636	1352.623	1718.388	2096.631	2498.362

PRUDHOE BAY ONLY

SEVERANCE TAX (MILLIONS OF $)										
NO ELF	1252.465	1124.336	992.6137	870.4757	816.1270	740.6450	664.8966	664.9124	661.5863	606.7882
WITH ELF	1252.465	1124.336	992.6137	714.2504	656.2593	580.2696	501.3609	498.1035	489.5263	433.5515
REVENUES RESULTING FROM										
REPEAL OF ELF	0	0	0	156.2253	159.8670	160.3754	163.5357	166.8089	172.0600	173.2367
CUMULATIVE TOTAL	0	9	0	156.2253	316.0931	476.4685	640.0042	806.8131	978.8730	1152.110

Figures calculated
by OMB

	1985	86	87	88	89	90	91	92	93	94
Gathering & Cleaning Charge	0	0	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ROYALTIES	0	0	6.095195	19.00111	20.06720	20.90120	22.16005	21.71606	19.97526	19.10337
TOTAL OIL PROD REVENUES	0	0	7.157300	27.95806	29.52439	30.06915	33.61522	35.40593	29.20774	27.79125
Endicott Prod.(MMbbl/d)	0	0	0	.019	.063	.065	.067	.069	.07	.056
Endicott Price ($/bbl)	15.99	14.351	12.62	12.44	13.22	11.89	14.76	15.91	17.22	18.64
Wells	1	1	1	34.5	111.5	111.5	111.5	111.5	111.5	100.05
ELF	0	0	0	.2992290	.3132327	.3301158	.3462700	.3617316	.3692138	.3080971
Nominal Tax Rate	0	0	0	0	0	.1225	.1225	.1225	.1225	.1225
Effective Tax Rate	0	0	0	0	0	.0404392	.0424181	.0443121	.0452207	.0377419
Royalty Percentage	.1438	.1438	.1438	.1438	.1438	.1438	.1438	.1438	.1438	.1438
SEVERANCE TAX (ELF)	0	0	0	0	0	11.41801	13.10932	15.20232	17.03779	12.31192
SEVERANCE TAX (NO ELF)	0	0	0	0	0	34.56366	37.85067	42.02652	46.14614	39.96116
CONSERVATION TAX	0	0	0	.0074222	.0246104	.0253917	.0261730	.0269542	.0273449	.0210759
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	12.40503	43.71432	47.30789	51.90584	57.61970	61.26783	54.73003
TOTAL OIL PROD REVENUES	0	0	0	12.40583	43.71432	50.79790	65.01476	72.02202	80.30502	67.09995
Kleburne Prod.(MMbbl/d)	0	0	.009	.017	.041	.061	.074	.075	.076	.078
Kleburne Price ($/bbl)	16.04	15.201	13.47	13.29	14.07	14.74	15.61	16.76	18.07	19.49
Wells	1	1	79.5	79.5	104.25	116.9	116.9	116.9	116.9	116.9
ELF	0	0	0	0	.1101111	.2693556	.3734924	.3801931	.3871543	.4002726
Nominal Tax Rate	0	.1225	.1225	.1225	.1225	.1225	.15	.15	.15	.15
Effective Tax Rate	0	0	0	0	.0134886	.0329961	.0560239	.0570590	.0580731	.0600409
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	2.405111	9.475243	20.66848	22.90657	25.47112	29.15107
SEVERANCE TAX (NO ELF)	0	0	4.742934	8.039158	22.56914	35.17745	55.33043	60.21016	65.79061	72.02004
CONSERVATION TAX	0	0	.0035930	.0067867	.0163680	.0243523	.0295422	.0299414	.0303406	.0311391
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	5.531119	10.30806	26.31969	41.02326	52.70326	57.35063	62.65771	69.36004
TOTAL OIL PROD REVENUES	0	0	5.531119	10.30806	28.00481	50.49851	73.37174	80.25719	88.12804	98.51110
West Sak Sands Prod.(MMbbl/d)	0	0	0	.022	.03	.044	.05	.055	.057	.062
West Sak Sands Price ($/bbl)	15.33	13.691	11.96	11.70	12.56	13.23	14.1	15.25	16.56	17.98
Wells	1	76	83.5	91	169.5	169.5	204	204	204	204
ELF	0	0	0	0	0	0	0	0	0	0
Nominal Tax Rate	0	0	0	0	.1225	.1225	.1225	.1225	.1225	.15
Effective Tax Rate	0	0	0	0	0	0	0	0	0	0
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	0	0	0	0	0	0
SEVERANCE TAX (NO ELF)	0	0	0	0	14.74171	22.77454	27.58202	32.01478	36.92940	53.40397
CONSERVATION TAX	0	0	0	.0087020	.0119766	.0175656	.0199609	.0219570	.0227555	.0247516
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	11.82418	17.1915	26.55923	32.16563	38.26797	43.06635	50.86093
TOTAL OIL PROD REVENUES	0	0	0	11.82418	17.1915	26.55923	32.16563	38.26797	43.06635	50.86093
Unspecified Onshore Prod.(MMbbl/d)	0	0	0	0	0	.018	.032	.033	.034	.035
Unspecified Onshore Price ($/bbl)	15.19	13.551	11.87	11.64	12.42	13.09	13.96	15.11	16.42	17.84
Wells	1	1	1	1	33.3	45.15	42	37.5	33	27.75
ELF	0	0	0	0	0	.1175305	.4642302	.5276255	.5899642	.6593604
Nominal Tax Rate	0	0	0	0	0	0	.1225	.1225	.1225	.1225
Effective Tax Rate	0	0	0	0	0	0	.0568602	.0646427	.0722706	.0807716
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	0	0	8.113455	10.29435	12.00590	16.18730
SEVERANCE TAX (NO ELF)	0	0	0	0	0	0	17.47722	19.59012	21.04183	24.42867
CONSERVATION TAX	0	0	0	0	0	.0071859	.012775	.0131742	.0135734	.0139727
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	0	0	10.75016	20.3016	22.74799	25.47153	28.40825
TOTAL OIL PROD REVENUES	0	0	0	0	0	10.75016	28.47505	33.04434	38.35742	44.59555
Seal Island Prod.(MMbbl/d)	0	0	0	0	0	0	0	0	0	0
Seal Island Price ($/bbl)	15.54	13.901	12.17	11.99	12.77	13.44	14.31	15.46	16.77	18.19
Wells	1	1	1	1	1	1	1	1	1	1
ELF	0	0	0	0	0	0	0	0	0	0
Nominal Tax Rate	0	0	0	0	0	0	0	0	0	0

14-1511
Bradley
01/16/86

IN THE HOUSE

HOUSE BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

FOURTEENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act relating to the oil production tax."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 43.55.013(b) is amended to read:

(b) [(1)] The economic limit factor for oil production of a lease or property shall be computed according to the following formula:

(1-[PEL/TP]) exp ([37,000,000 X WD]/[PEL X TP/Days])

[(1-[PEL/TP]) 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; [AND]

Days = the number of days in the month for which the tax is to be paid; and

where "exp" indicates that the expression following it is an exponent.

[(2) IF, FOR ANY MONTH DURING THE FIRST 10 YEARS FOLLOWING THE COMMENCEMENT OF COMMERCIAL OIL PRODUCTION OF A LEASE OR PROPERTY, THE ECONOMIC LIMIT FACTOR FOR OIL PRODUCTION OF THAT LEASE OR PROPERTY COMPUTED UNDER (1) OF THIS SUBSECTION IS 0.7 OR LESS, THEN THAT FACTOR SHALL BE APPLIED.

(3) IF, FOR ANY MONTH DURING THE FIRST 10 YEARS FOLLOWING THE COMMENCEMENT OF COMMERCIAL OIL PRODUCTION OF A LEASE OR PROPERTY, THE ECONOMIC LIMIT FACTOR FOR OIL PRODUCTION OF THAT LEASE OR PROPERTY COMPUTED UNDER (1) OF THIS SUBSECTION IS GREATER THAN 0.7, THEN THE

ECONOMIC LIMIT FACTOR IS ONE.

(4) THE ECONOMIC LIMIT FACTOR FOR OIL PRODUCTION OF A LEASE OR PROPERTY AFTER THE FIRST 10 YEARS FOLLOWING THE COMMENCEMENT OF COMMERCIAL OIL PRODUCTION SHALL BE COMPUTED AND APPLIED UNDER (1) OF THIS SUBSECTION.]

INTERIM REPORT OF THE

HOUSE FINANCE SUBCOMMITTEE ON OIL AND GAS

Prepared by

Louann Cutler, Staff
Representative Al Adams

and

Sharman Piper, Staff
Representative Sam Cotten

at the direction of

Rep. Sam Cotten, Chairman
House Finance Subcommittee on Oil and Gas

January 17, 1986

REPRESENTATIVE
SAM COTTEN
DISTRICT 15

PO BOX 296, EAGLE RIVER, AK 99577
POUCH V, JUNEAU, AK 99811

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES

MEMORANDUM

FROM: Representative Sam Cotten Sam Cotten
Chairman, House Finance Subcommittee on Oil and Gas

TO: Members of the Alaska State Legislature

RE: Interim Report of the House Finance Subcommittee on Oil and Gas

DATE: January 17, 1986

One of the most important aspects of Alaska public policy is our treatment of the oil and gas industry. Formulating oil and gas policy is difficult because of the huge amounts of money involved and because the state and the industry have different points of view. The industry is naturally interested in maximizing its profits. State government is concerned with adequately providing for the health, education and welfare of all Alaskans as well as developing its natural resources in a manner consistent with the public interest. Even though the state and the industry are united in our desire to promote oil and gas development, multi-million dollar disputes over fair tax policy and proper valuation of North Slope oil divide us.

Currently facing us is whether to reinstate separate accounting, proposed in House Bill 353, introduced last session by the House Finance Committee. The oil corporations have widely advertised their opposition to the bill throughout the state. Ironically, while they resist the tax changes embodied in HB 353, they have not paid taxes due the state from past tax years, choosing instead to dispute these taxes through established channels. Recent figures from the Department of Revenue (DOR) show the oil companies are hundreds of millions of dollars behind in tax payments to the state, under former and existing tax laws.

During the interim I examined these tax issues and other areas of dispute in order to suggest improvements to state policy, increase our understanding of the issues involved, and improve our relationship with this vital Alaskan industry.

We depend on an unstable entity -- world oil prices -- for the bulk of our state revenues and this makes it difficult to plan. But even with this uncertainty, Alaska can implement smart business practices. For example, we can't let the oil and gas industry write its own tax laws. On the other hand, we need a policy that encourages exploration and development. We also have to be realistic and realize that state tax incentives alone cannot overcome the current world-wide slump in oil prices.

We need to spend less on government operations and broaden our economic base. Our policies should focus on the decline in Prudhoe production, which will start occurring in the next few years, and the inability of subsequent oil fields to come close to equalling Prudhoe's output. In other words, our present generous level of oil revenues is short-lived. Our goals should be to maximize our benefits now from this non-renewable resource and to encourage additional exploration and production so that we can prepare for a future without as many oil dollars.

It is my hope that this report will help provide a framework for our continuing relationship with the oil industry. Some of the issues discussed here include recommendations for legislation, others are offered as background information.

The topics discussed in the report are as follows: 1) prepayment of disputed taxes; 2) an examination of the issues having to do with separate accounting (HB 353); 3) a discussion of the severance tax and the economic limit factor; 4) an overview of the major oil litigation.

I. Prepayment of Disputed Taxes

One of the most disturbing developments to surface during the interim was the discovery that the oil companies are $908 million behind in tax payments to the state as of January 6, 1986. Confidentiality statutes prevent disclosing the names of the corporations and exactly how much each owes, but the large sums and statutes involved make it obvious that the major North Slope producers -- Arco, Exxon, Sohio -- are some of the taxpayers whose accounts are at issue. Furthermore, current law offers little incentive for them to pay in a timely manner.

Properly written statutes could have the companies prepay assessed amounts at a set point in the appeals process -- late enough to protect the taxpayers from auditing errors yet early enough to ensure that the taxes are collected in a timely manner.

Additionally, the Legislative Budget and Audit Committee has requested an opinion from the attorney general's office on the constitutionality of revealing the names of taxpayers whose accounts are past due.

II. The Issues Pertaining to Separate Accounting -- HB 353

HB 353 would reinstate separate accounting as the method used to calculate the oil industry's tax liability. It would also reduce the severance tax from 15% to 12.25%, a substantial incentive to smaller fields. Industry protests about the bill obscure the fact that it is a fairer tax because it lowers the income tax on less profitable ventures, like marginal fields, and puts the tax burden on the most profitable developments, such as Prudhoe Bay and Kuparuk.

HB 353 would ensure that the state receives its fair share of Alaskan oil wealth. On Jan. 13, 1986 the U.S. Supreme Court agreed with the Alaska Supreme Court that separate accounting is constitutional. Furthermore, the state supreme court said that separate accounting is the prevailing method used throughout the United States for reporting income from oil production because it conforms more to an oil company's financial accounting procedures and "more accurately reflects income than formula apportionment".

Under pressure from important US trading partners, President Reagan has asked Congress to force states to abandon worldwide combination formula apportionment.

Whether or not we decide this session to return the former tax law to the books, it's important to understand the basic issues involved and let our decisions on tax policy be guided by facts, not by high-priced media campaigns aimed at our emotions.

III. The Severance Tax and the Economic Limit Factor

This is an issue that needs to be addressed this session because state revenues from severance taxes will be severely reduced beginning in FY 88 if the ELF law isn't changed. The ELF is a statutory reduction to the severance tax, created to extend production on marginal fields, but it is not working as well as it could. Two problems with present law are: 1) it doesn't give marginal fields enough of a tax break; and 2) it will provide Prudhoe with a premature tax reduction decades before it can be considered marginal. A simple change in the ELF law could solve both these problems.

IV. Major Oil Litigation with the Oil and Gas Industry

The amounts at issue in the state's oil and gas litigation are at least $15 to 20 billion dollars and the state has spent millions of dollars so far to pursue these cases. Major litigation with the oil industry highlights the many points during the production and marketing process that provide profit-making opportunities for the industry and and revenue opportunities for the state.

This chapter of the report highlights two major cases that affect the value of the oil and revenues to the state. The cases are the Amerada Hess royalty case and the TAPS tariff case. While the issues involved are in litigation and therefore out of the legislature's immediate realm of influence, I believe knowing more about the nature of the disputes adds to our overall understanding of the subject. Fair prices for the oil and fair charges for transportation costs are the key areas in which the state and oil companies disagree.

The issues summarized above constitute this interim report. It is my hope that the information will be of use to you as we begin the 1986 session. The report does not attempt to address all the facets of the state's complex relationship with the oil and gas industry, but it does touch on some of the important points. I believe staying abreast of the industry and its goals will enhance the quality of state government, because without this knowledge it will be difficult to maintain our positions as the real policymakers of Alaska.

INTERIM REPORT OF THE HOUSE FINANCE SUBCOMMITTEE
ON OIL AND GAS

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I.

PREPAYMENT OF DISPUTED TAXES

I. The Problem

As of January 6, 1986, the oil companies owed the state $908 million in disputed taxes. Due to the ARCO settlement of $243 million on January 13, 1986, this total will be adjusted (new figures from DOR are expected next week). Since $243 million is the amount of the settlement, it may not be the exact amount of taxes previously in dispute between ARCO and the state. The phrase "disputed taxes" refers to audited tax amounts contested by the companies, plus interest and penalties. Unfortunately, existing state law does not encourage speedy resolution of these cases and some of the disputes go back as far as 15 years.

The total reported by DOR to be disputed on Jan. 6, 1986 was $908,293,008.61. The total amount varies from month to month due to such causes as interest charges and settlement of some of the disputes. For a schedule of all tax accounts receivable, see Attachment A. Here is a breakdown of what is owed:

-- Approximately $524 million of the total is owed under the former separate accounting oil and gas corporate income tax for the years 1979 to 1981. (AS 43.21)

-- Approximately $322 million is owed under the severance tax for the years 1976 to 1982. (AS 43.55)

-- The balance of about $62 million is owed under the income tax statute for all corporate taxpayers.[1] (AS 43.20) While the $62 million includes contested taxes for all corporate taxpayers, it is estimated that almost all of this amount is owed by the oil and gas corporations.

The main reason the taxes have not been paid is because the oil companies disagree with the state over the amount of their tax liability. They are contesting the tax assessments through established administrative channels in the Department of Revenue. At issue is the methodology for calculating certain revenues and expenses in order to determine the amount of tax owed to the state.

A second reason the taxes have not been paid is that many of the issues involved in the tax disputes are the subjects of major oil and gas litigation between the companies and the state.

A third reason the taxes have not been paid is that the companies appear to have little incentive to do so. Although interest rates on disputed tax liability (12% per AS 43.05.225) may currently be higher than commercial interest rates, it is clearly in the taxpayers' interest to

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[1] Before 1979 oil and gas companies paid income taxes under AS 43.20, like all other corporate taxpayers. Between 1979 and 1981 they paid income taxes under the separate accounting statute, AS 43.21, and also paid income tax for their non-oil and gas activities under AS 43.20. From 1982 to now, the companies again pay all their income tax under AS 43.20.

prolong the tax disputes and avoid payment for as long as possible. They may also hope for a settlement with the state in which they ultimately pay a smaller amount than originally assessed.

II. The Disputed Issues

The major severance tax issues are similar to those involved in the State v. Amerada Hess, et. al case, though resolution of the tax issues may well be different than the case itself. (The last chapter in this report discusses this case in more detail.) The amount of our royalty share is in question in this lawsuit because of a dispute over the wellhead value of the oil. The wellhead value is determined by the destination price of the oil minus the transportation costs -- primarily pipeline tariffs and tanker charges. The tanker charges and destination price are at issue in the Amerada Hess case and about 95 percent of the total disputed taxes owed under the severance tax law involve these issues.

The remaining severance tax disputes primarily involve: 1) what production expenses can be deducted; 2) the computation of pipeline income; 3) what income and expenses are non-oil related and should be taxed under the income tax statutes; and 4) proper pipeline tariffs for non-TAPS pipelines, such as the Kuparuk pipeline and the Panama Canal pipeline.

Roughly half of the separate accounting disputes involve all the issues involved in the severance tax disputes. The other half of the separate accounting disputes involves these major issues: 1) how to compute production expenses; 2) how to compute pipeline income; 3) income and expenses that should be apportioned to AS 43.20; 4) appropriate pipeline tariff charges; 5) how much should be spent for the eventual closing down of the pipeline; and 6) how much value should be placed on recoverable reserves.

The separate accounting tax disputes are also similar to those in Arco, et. al. v. State, the lawsuit over the state's former separate accounting law (described in the second chapter of this report). Now that separate accounting has been upheld at every level of court review -- most recently by the US Supreme Court this past Monday when it dismissed the oil companies' appeal -- the Department of Revenue expects these tax disputes to progress further.

III. Existing Process for Resolving Tax Disputes

After an oil and gas corporation submits a tax return it is audited by the Department of Revenue. Generally speaking, the audit shows that the taxpayer owes more than the taxpayer's return says. The taxpayer is then assessed the audited amount. Again, generally speaking, the taxpayer contests the audit and the arduous process of resolving the dispute begins.

The first stage of the resolution process is referred to as the informal conference stage and almost 90 percent of currently disputed taxes are in this stage. This is when

DOR and the taxpayer try to resolve factual issues and agree on the amount of tax owed, a process that can take several years. If the dispute is resolved, the taxpayer pays the additional amount and the case is closed. (In some rare instances, the informal conference is skipped and the dispute is taken up immediately at the formal hearing level.)

If it is not resolved, the case moves along to the formal hearing stage. A DOR hearing examiner essentially acts in the capacity of a judge and decides the case. This stage can also take years. The Commissioner can either adopt or reject the decision, although all decisions ever issued have all been adopted.

After adoption of the decision, the taxpayer is required to pay the tax if no appeal is filed in the superior court. If the taxpayer pursues the dispute by appealing to court, then the court will require that a bond be posted in order to continue contesting DOR's decision.

IV. Inadequacy of the current resolution process

Because of our current dispute resolution process, it may take years before the taxpayers will settle or be required to pay the audited tax amounts. Some of the disputes concern taxes that were owed as far back as 1970 although in certain instances, audits may not have been performed until years after a return is filed because the assessment period has been waived.

The taxpayer then has no incentive to resolve the matter since he is not required to pay the audited tax until all the administrative and judicial channels to overturn the audit have been exhausted. By allowing the taxpayer to keep the disputed amounts for so long, current laws appear to encourage the taxpayer to prolong the dispute. Thus the taxpayer will have the disputed funds to invest and earn interest on, or to use for other purposes.

V. A Solution: Prepayment of Assessed Tax Amounts

In order for the state to collect taxes in a more reasonable time frame, the oil companies should be required to prepay the audited amount at some point in the dispute resolution process.

Prepayment could be required after the informal conference stage. At this point the taxpayer and the state have been negotiating and fine-tuning the tax liability for some time. Errors and omissions by the taxpayer and auditor are likely to have been corrected.

Alternatively, prepayment could be required after the formal hearing. The dispute has been reviewed by the entire DOR hierarchy and the Commissioner has adopted a decision. If prepayment is not required until after the formal hearing, specific time frames could be provided in law for each stage of the resolution process. Once the taxpayer has been assessed the audited amount, both the informal conference and formal hearing stages would have to be completed within a certain number of years established in statute. This would guard against continued prolonging of disputes since prepayment would not be required until the end point of the department's internal review.

It makes fiscal sense to put some or all of the prepayments in escrow until the dispute is finally resolved. The escrow account could be viewed as a form of state savings, since it could still be several years until a particular dispute is finally resolved. In the meantime, the escrowed amounts could earn be invested and earn additional income. This would allow the state to save for the future and also provide protection in the event that the disputed tax liability would be resolved in the taxpayer's favor.

The prepayment requirement should also be applied to amounts owed for prior tax years. Applying the prepayment requirement to past years is essential in order to bring about faster resolution of the current tax disputes, since these disputes involve tax liabilities for earlier years.

Prepayment has precedents at both the state and federal levels. It is currently required by the IRS if the taxpayer decides to appeal to the federal district court or court of claims rather than to tax court. In fact, DOR currently has a prepayment regulation on the books that requires payment of estimated severance taxes but it only applies to the returns for the years after 1984 (14 AAC 55.165). (It also only addresses the issue of oil valuation, not transportation assessments.) The regulation requires prepayment of an average amount owed by all taxpayers; it does not relate to actual assessed tax liability. This regulation only applies to the severance tax and does not capture back taxes owed under the two corporate income taxes.

A form of prepayment was also a provision of the state's former separate accounting law (in effect for the years 1979-1981). Since the language was vague on whether audited amounts were covered, DOR never enforced the statutory prepayment requirement for the assessed amounts. In enacting this prepayment provision, it is likely that the legislature did not foresee the need for extensive audits and the resultant lengthy dispute resolution process. However, the former prepayment provision can certainly be thought of as a precedent for the kind of prepayment advocated here, especially since the language was never contested by the taxpayers.

The Department of Law has informally advised that there are no legal problems with prepayment. A comprehensive and formal opinion, prepared by both the attorney general's office and the Department of Revenue, is expected early next week.

VI. Conclusion

The legislature should provide by statute for prepayment of audited tax amounts at a set point in the resolution process. This will insure the state receives its share of oil revenues in a more timely manner and also protect the taxpayers from any initial auditing errors.

Such a prepayment requirement should not be viewed as an additional burden to the oil companies since the revenue that could be raised does not come from implementing new taxes; rather, it is revenue the state should have already received.

ALASKA DEPARTMENT OF REVENUE

APPEALED TAX ASSESSMENTS BY APPEAL LEVEL

January 6, 1986

TAX TYPE	STATUTE	VALUE OF ACCOUNTS	CONFERENCE	FORMAL	COURT
OIL & GAS CORP INC	AS 43.21	$524,163,0[illegible].65	$438,358,422.69	$85,804,673.96	$ .00
OIL & GAS PRODUCTION	AS 43.55	321,697,462.15	300,848,926.97	20,848,535.18	.00
CORPORATE INCOME	AS 43.20	62,432,449.81	47,639,282.76	13,773,985.93	1,019,181.12
INDIVIDUAL INCOME	AS 43.20	2,844,081.31	2,828,965.29	15,116.02	.00
BUSINESS LIC GR RCPT	AS 43.70	2,686,323.31	1,777,731.64	524,380.37	384,211.30
FISHERIES	AS 43.75	1,925,335.87	1,150,173.69	775,162.18	.00
MOTOR FUEL	AS 43.40	1,525,206.60	970,498.59	554,708.01	.00
MINING	AS 43.65	828,697.24	828,697.24	.00	.00
OIL & GAS PROPERTY	AS 43.56	385,779.18	9,321.98	.00	376,457.20
FIDICUARY INCOME	AS 43.20	183,636.52	183,636.52	.00	.00
SALMON ENHANCEMENT	AS 43.76	42,535.97	29,618.97	12,917.00	.00
ESTATE	AS 43.31	30,840.49	30,840.49	.00	.00
SEAFOOD MARKETING	AS 16.51	8,119.55	8,119.55	.00	.00
INDIVIDUAL WITHHOLD	AS 43.20	7,610.85	7,610.85	.00	.00
TOBACCO (CIGARETTE)	AS 43.50	4,487.22	4,487.22	.00	.00
WHSL CANNED SALMON	AS 43.80	2,250.00	2,250.00	.00	.00
LIQUOR EXCISE	AS 43.60	485.13	485.13	.00	.00
COIN OPERATED DEVICE	AS 43.35	.00	.00	.00	.00
TOTAL TAX ACCOUNTS RECEIVABLE		$918,768,397.85	$794,679,069.58	$122,309,478.65	$1,779,849.62
PERCENT OF TOTAL VALUE		100.00%	86.49%	13.31%	0.20%

TAX TYPE	STATUTE	NUMBER OF ACCOUNTS	CONFERENCE	FORMAL	COURT
OIL & GAS PRODUCTION	AS 43.55	496	413	83	0
CORPORATE INCOME	AS 43.20	405	314	82	9
INDIVIDUAL INCOME	AS 43.20	253	243	10	0
MOTOR FUEL	AS 43.40	153	92	61	0
FISHERIES	AS 43.75	54	41	13	0
BUSINESS LIC GR RCPT	AS 43.70	42	32	8	2
OIL & GAS CORP INC	AS 43.21	36	21	15	0
SALMON ENHANCEMENT	AS 43.76	20	18	2	0
MINING	AS 43.65	8	8	0	0
SEAFOOD MARKETING	AS 16.51	7	7	0	0
FIDICUARY INCOME	AS 43.20	7	7	0	0
INDIVIDUAL WITHHOLD	AS 43.20	5	5	0	0
OIL & GAS PROPERTY	AS 43.56	5	4	0	1
WHSL CANNED SALMON	AS 43.80	3	3	0	0
TOBACCO (CIGARETTE)	AS 43.50	2	2	0	0
ESTATE	AS 43.31	2	2	0	0
LIQUOR EXCISE	AS 43.60	1	1	0	0
COIN OPERATED DEVICE	AS 43.35	0	0	0	0
TOTAL TAX ACCOUNTS		1,499	1,213	274	12
PERCENT OF TOTAL ACCOUNTS		100.00%	80.92%	18.28%	0.80%

II.

OVERVIEW OF ISSUES

PERTAINING TO HB 353

I. What does HB 353 do?

A. HB 353 would reinstate separate accounting as the method that the oil industry must use to compute income earned in Alaska to determine its income tax liability to the state.

B. HB 353 returns the nominal severance tax rate from 15% to its pre-1981 level of 12.25%. The nominal rate was raised in 1981 at the same time that separate accounting was repealed in order to compensate for the loss in tax revenue anticipated at the time due to implementation of modified apportionment.

II. Summary

A. HB 353 will insure that the state receives its fair share of Alaskan oil wealth. The industry's share has increased since the 1981 tax changes while the state's share has decreased. The changeover has cost the state approximately $850 million from FY82 through FY86 and an additional $1.4 billion can be raised from FY87 through FY2005 if the state returns to its pre-1981 tax structure.

B. The Alaska Supreme Court has found that separate accounting is constitutional in every respect. The court even declared that it is a better measure of oil industry income in Alaska than formula apportionment. The US Supreme Court essentially concurred in this decision on January 13, 1986, when it refused to review the industry's appeal of the state court's ruling.

C. Separate accounting is a fairer tax because it will lower the income tax on less profitable investments like marginal field exploration and development and raise the income tax on highly profitable fields like Prudhoe Bay (i.e., conventional recovery in the Sadlerochit reservoir). The industry can afford a higher income tax on Prudhoe because it made as much in FY 85 as it made in FY 82 (about $6 billion in real terms) even with the downward price spiral. Additionally, the income tax increase on Prudhoe would be coupled with a 22% severance tax decrease under HB 353.

D. Future tax policy should be directed by the overwhelming importance of Prudhoe Bay to our revenue stability. Even with marginal field development, Prudhoe is still expected to provide almost 80% of production through 2010. Almost two thirds of recoverable reserves in Alaska are found in Prudhoe.

III. Background

A. After four years of comprehensive study, the 1978 legislature changed the method of accounting that oil companies must use to compute their corporate income tax liability from formula apportionment to separate accounting.

It was determined that separate accounting would more accurately reflect how much of an oil company's income is earned in Alaska.

B. The constitutionality of separate accounting was quickly challenged by the major oil companies in Arco v. State. The 1981 legislature was faced with the threat of having to refund about $9 billion in 1985 when resolution of the litigation was expected. In response to this threat, the legislature repealed separate accounting and enacted modified apportionment in its place. In 1983, an Anchorage superior court judge ruled that separate accounting is constitutional. This decision was unanimously upheld by the Alaska Supreme Court in August, 1985. It was again upheld this past Monday, January 13, 1986, when the US Supreme Court refused to review the industry's appeal of the state supreme court's ruling, thus ending the lawsuit.

C. Definitions:

1. Formula apportionment: If a firm operates in several states and one of the states wishes to tax its income, a method must be chosen to determine how much income was actually earned in the taxing state. The formula apportionment method looks at the firm's worldwide income and, by use of a formula, attributes part of it to the taxing state. The standard formula uses three indicators of business presence in the state: payroll, property and sales.
2. Modified apportionment: This is a modified version of formula apportionment. It is different because of the substitution of the extraction factor for the payroll factor since the former is a better indicator of oil industry presence in Alaska. The extraction factor helps to determine income from oil production by measuring the amount of a company's in-state production activity. Since in Alaska production is far more prevalent than marketing and refining, modified apportionment more accurately determines oil company income and profitability in Alaska than does the standard formula apportionment method.
3. Separate accounting: This method does not use a formula to carve out a portion of worldwide income and attribute it to Alaska. Instead, it takes the wellhead value of oil (gross income) in Alaska and deducts from it all the costs of production to arrive at net income. This amount is then taxed at the same corporate income tax rate that all other non-oil businesses pay. Because it is considered by many to be the most accurate way to measure the value of oil production activity it comes closest to measuring income earned only in Alaska, and therefore, the income of oil companies directly attributable to business activities in Alaska.

IV. What important issues are involved in deciding whether to enact HB 353?

A. Is separate accounting a better, fairer way to tax the oil industry in Alaska?

B. Will HB 353 discourage further exploration and development of new oil fields in Alaska?

C. Will HB 353 destabilize Alaska's business climate?

D. How will a return to separate accounting affect our tax revenues?

E. How will a reduction in the severance tax affect our tax revenues?

F. How will the inevitable decline in Prudhoe Bay production affect Alaska's revenue picture?

G. Should the legislature consider any other changes to our oil & gas tax structure?

H. What is the current status of <u>Arco v. State</u>?

I. Was there a conspiracy in 1981?

J. How healthy is the oil industry at present?

K. How does taxation of the oil industry in Alaska compare to taxation of the industry in other states and at the federal level?

These questions are answered in the following sections.

V. Is separate accounting a better and fairer tax accounting method for Alaska?

A. This issue poses two major questions: (1) Which method -- separate accounting or formula apportionment type of accounting -- best measures the amount of income earned within the taxing state? A fair tax will only apply to income earned in that particular state. (2) What is Alaska's "fair share" of the oil wealth provided by our oil resources?

B. Question #1 was answered by the legislature in 1978, again by Alaska courts in both 1983 and 1985, and again by the US Supreme Court last Monday. <u>In August, '85, the Alaska Supreme Court stated that separate accounting</u> is the prevailing method throughout the United States for reporting income from oil production because it conforms more to an oil company's financial accounting procedures and <u>"more accurately reflects income than formula apportionment</u>. ...[T]he Alaska legislature turned to separate accounting for oil producing businesses only after it determined that <u>the use of formula apportionment to compute Alaska's share of oil production income would</u>

seriously underestimate the production income that was rightly subject to taxation by this state (emphasis added)." The Court noted further that the case of Sohio is the best illustration of the superiority of separate accounting as a means of allocating income earned in a particular jurisdiction. During the period 1978-80, Sohio maintained that only 10% of its payroll, 12% of its sales and 50% of its property were in Alaska. Yet its 1980 annual report states that over 90% of its total oil production derived from reserves in Alaska. Additionally, documents submitted to the Court (and not disputed by the companies) indicate that Sohio's earnings had elevated it from 17th to 7th industrywide. So, the Court concluded, "... the traditional formula apportionment method would inadequately reflect the phenomenal value of the companies' oil reserves in Alaska."

C. Separate accounting is also superior to modified apportionment because it taxes conventional recovery at Prudhoe Bay more heavily than less profitable ventures, such as new technology applications at Prudhoe, and exploration and development in marginal fields. These less profitable ventures will actually experience an income tax reduction under separate accounting, just as Prudhoe will experience a tax increase. Prudhoe can afford to pay more taxes and still be highly profitable. A 1984 Institute of Social & Economic Research (ISER) study found that Prudhoe had made the companies about $9 billion in net profits and that its 1982 profit rate hovered around 25%. But some of the riskier investments that industry is making in Alaska that are expected to yield a less-than-average profit could use an additional tax break. This would be a much more equitable approach than modified apportionment which taxes all industry activities at approximately the same rate regardless of risk and expected profit.

D. With regard to question #2, Alaska's fair share should be thought of principally in philosophical terms rather than only in terms of numbers. The following comments were made in a joint statement from the Governor and the legislative leadership in March, 1981: "[A]ny significant decreases in State oil and gas revenues appear both unwarranted and unsupported by the majority of Alaskans. The State's current level of taxation ... provides that both the oil companies and the federal government will receive greater shares of Alaska's wealth than will Alaskans. Accordingly, any greater percentage granted the former at the expense of the latter would be inequitable ... All agree that any changes [to the tax code] that would give large sums of money to the oil industry at the expense of the people of Alaska are unacceptable." These statements express the philosophy behind Alaska's oil and gas tax code and provide a framework for determining if Alaska receives its fair share of the oil wealth. They continue to be relevant in 1986.

E. With this philosphy firmly in mind, consider a "shares" analysis prepared by economist Eban Goodstein in mid 1985. He found that in FY82, shares of oil wealth in Alaska were divided as follows: industry - 41%, federal government - 30%, and state government - 29%. By FY85, the shares had shifted such that industry received 50%, the federal government received 22% and the state received 27%.

F. Alaska is not receiving its fair share as defined by the Governor and the legislature in 1981 because its share has declined while the oil industry's share has increased. Goodstein's analysis further suggests that <u>the change from separate accounting to modified apportionment was one of the reasons why Alaska's share diminished and the industry's share increased</u>. His study concludes that if separate accounting had not been repealed, the FY82 shares would have been 42% industry, 30% federal government and 28% state government while the FY85 shares would have been 47% industry, 21% federal government and 33% state government. A shares analysis prepared by the House Research Agency in December, 1985, compares closely with the Goodstein analysis for the years FY82 through FY85.

VI. Will HB 353 discourage exploration and development?

A. The major determinants of a company's decision to explore and develop a particular oil field are availability of the oil, the price of oil, and the cost of production in that particular field. These factors determine the rate of return which in turn determines whether or not a field will be explored or developed. Since a state's tax rate is only one aspect of the cost of production, and the cost of production is only one factor in the rate of return equation, it follows that the tax rate can only play a small role in the company's final decision to explore or develop. Although taxation may have a psychological affect on a company's decision, it will rarely be the principal factor in the decision making process. <u>The overall rate of return is the ultimate decision maker and the rate of taxation plays only a small part in determining that rate of return</u>. As the ISER report states: "[F]our factors are typically more important than state tax rates in shaping the pattern of resource development." These factors are described as geologic good fortune, ownership of the mineral rights, cost environment and world energy prices.

B. Unlike formula or modified formula apportionment, separate accounting only taxes a company on profits made in Alaska. In fact, a company will only pay a tax on profitable fields in Alaska so that if it has production activity at Prudhoe Bay and exploratory activities elsewhere, it will only pay taxes on the Prudhoe production activity because it does not yet derive any income from its exploratory work. Moreover, separate accounting would allow the company to deduct its exploratory expenses from its Prudhoe tax liability. Apportionment, on the other hand, taxes a portion of a company's worldwide income so the company will pay taxes in Alaska even if all its profits were made elsewhere and even if its Alaskan activities operate at a loss. Separate accounting, then, is a better incentive for exploration and development since a company will not pay taxes until the field it is exploring or developing starts to produce and generates a profit. In a letter to the House Finance Committee, ISER economics professor Matthew Berman explained this effect as follows: "[S]eparate accounting...has virtually no adverse effect on development of marginal fields. A firm ...will make the investment only if it expects such development to be profitable after subtracting all taxes. Under... separate accounting... the proposed investment...will generate a tax liability...only if the investment is profitable anyway." Berman continues, "Corporate income taxes assessed under the modified apportionment system... may have some adverse effects [because] any investment, profitable or not, will generate an Alaska income tax liability." Berman reaches the same conclusion for exploration of marginal fields. A mid 1985 issue of Pacific OCS News, a trade journal, made a similar observation about Conoco's development of Milne Point: "The start up of this field begins a new era of marginal, N. Slope projects ... If the state returns to the pre-1982 'separate accounting' tax methods, it could offer a significant incentive to this type of small development, because it would be taxed on its own profitability and not on the companies' national profit base."

C. Exploration and development takes place in many jurisdictions that require separate accounting. Foreign nations, the US Government, Oklahoma, Louisiana and Mississippi all utilize separate accounting and all have experienced exploration and development activity.

D. Although the industry indicated to the legislature last session that a return to separate accounting would hamper their exploration and development activities in Alaska, their annual reports appear to lead their shareholders to a much different conclusion. Take, for example, the annual reports of ARCO from 1978 to 1981, the years that separate accounting was on the books. In 1978, ARCO's earnings were up 15%; in 1979, they were up 45%; in 1980, they were up 42%; and in 1981, they were up slightly again. "As it was in 1978", ARCO informed its shareholders, "the North Slope of Alaska was a prime source of the Company's earnings improvement in 1979." Clearly, separate accounting did not interfere with its earnings nor its exploration and development plans. These plans were in fact expanded dramatically during the separate accounting years. The 1979 annual report states: "For its part, Atlantic Richfield has dramatically intensified its search for new domestic reserves of oil and gas." Exploration and development occurred within Alaska during these years. For example, Kuparuk development was started in 1979 and completed in 1981, "three months ahead of schedule", according to the 1981 ARCO annual report. Surprisingly, the first year that ARCO complains about its tax burden to its shareholders is 1982 -- a full year after Alaska repealed its separate accounting statute.

E. According to economist Goodstein, the oil companies made so much money in Alaska between 1982 and 1985 that $24 billion in profits went outside. According to ARCO Alaska president Harold Heinze's remarks to the Committee last spring, the industry has invested about $6 billion in Alaska during this period. Perhaps more of the $24 billion that went outside would also have been invested in Alaska if separate accounting had been on the books to encourage marginal exploration and development without paying taxes.

F. HB 353 should also encourage exploration and development because it reduces the amount of severance tax that a company would pay. As Vince Wright with the Department of Revenue pointed out to the House Finance Committee in May, 1985, "On the severance tax side ... what you have done is lowered the rate from 15% to 12.25% so in fact ... this might be more of an inducement to expand exploration." For fields that have a 15% rate now, HB 353 would result in a 22.4% reduction in severance taxes.

VII. Will HB 353 create an unstable business climate for the oil industry in Alaska?

A. Since HB 353 will encourage exploration and development, it should make Alaska's business climate even more attractive to the industry.

B. Since 1955, the state's oil tax structure has been through eleven major changes. HB 353 must be viewed in this historical context. A state's tax code should be dynamic and flexible as well as a reflection of a state's changeable economic picture and public policy goals.

C. HB 353 does not create any new taxes. It merely reinstates taxes that were on the books before 1981. Moreover, separate accounting was repealed in 1981 largely because of the threat posed by the lawsuit. The US Supreme Court has laid that issue to rest and HB 353 merely returns our system to its pre-1981 state. The House floor debate on the 1981 amendments indicates that a bill like HB 353 was in fact anticipated. Consider the comments of the majority leader in the House at the time the amendments were enacted: "[B]y that time... 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." Apparently it was expected that the legislature would reconsider its oil and gas tax structure once the constitutional status of separate accounting was determined.

D. It is perhaps more appropriate to view the legislature's 1981 action as the one that created an unstable business climate. This is especially true in light of the fact that the 1981 revisions did create an entirely new method of accounting for income tax liability. Modified apportionment is not used by any other state that relies heavily on oil production activity. And, whereas separate accounting was adopted only after four years of careful, comprehensive study of all tax possibilities, modified apportionment was adopted with little analysis and hardly any debate.

E. Another way to look at stability is from the state's point of view. A stable revenue stream to provide necessary public services is just as important to Alaskans as maintaining a stable business climate. This is especially true in light of the fact that government dollars in large part determine the health of Alaska's economy. <u>The 1981 amendments destabilized our revenue stream because they reduced our share of the oil money. HB 353 returns us to the old system, returns us to our pre-1981 share of the wealth, and, therefore, stabilizes our revenue stream</u>.

VIII. How will a return to separate accounting affect our tax revenues?

A. The Department of Revenue's 10/31/85 fiscal analysis of HB 353 shows that, according to the mean revenue projections, <u>the bill would increase our tax revenues by about $1.4 billion</u> between FY87 and FY2005. (A new fiscal analysis from DOR is expected in early 1986 that will analyze the impact of the TAPS settlement on the tax structure proposed in HB 353.) Beginning in FY2000, the DOR fiscal note predicts that the state would make less from separate accounting and the lowering of the severance tax than if the higher severance tax and modified apportionment were in effect. This is because of Prudhoe's decline in relation to profits companies will make elsewhere in the world.

B. It is disturbing to note that the Department's analysis shows that <u>the 1981 tax changes have cost the state approximately $850 million</u> in tax revenues from FY82 through the end of the current fiscal year.

IX. <u>How will the proposed severance tax affect our tax revenues</u>?

A. Because HB 353 lowers the nominal severance tax rate from 15% to 12.25%, severance tax revenues are reduced. However, because of the separate accounting impact, <u>overall</u> tax revenues are increased (see previous section). The DOR fiscal note shows that if the nominal rate was not reduced in HB 353, the state would gain an additional $1.5 billion between FY87 and FY2005 or a total additional gain of approximately $2.9 billion from reimposition of separate accounting and leaving the nominal severance tax rate at 15%.

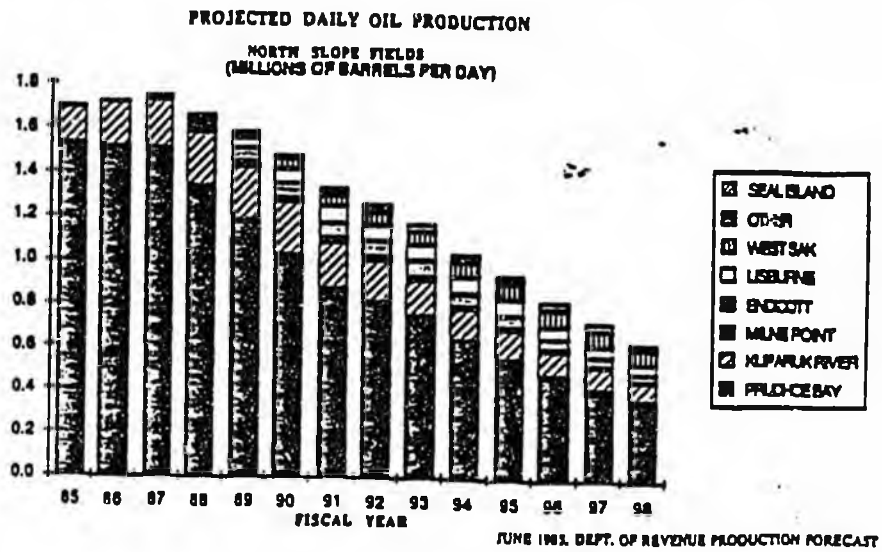
B. It is important to understand another impact of reducing the nominal severance tax. The actual severance tax paid by the taxpayer depends on the economic limit factor (ELF). When applied to the nominal rate, the ELF reduces the effective rate and therefore the actual amount of severance tax that is paid to the state. Beginning in FY88 when Prudhoe production starts to decline, the ELF will cause our severance tax receipts to decline dramatically because it will lower our severance tax revenues from Prudhoe considerably. According to DOR's June 1985 revenue forecast, FY88 severance tax receipts will be $230 million less than FY87 receipts. Since HB 353 drops the nominal rate, that change in combination with the ELF will increase the $230 million drop by another $143 million, according to calculations made from OMB data.

C. An OMB analysis indicates that repeal of the ELF could bring the state an additional $2.4 billion in revenues from FY87 to FY94.

D. The ELF was developed because it was thought that the burden of the severance tax would tend to close a field down before all the oil was taken out of it. The ELF is designed to prolong the life of a field -- and therefore stretch oil revenues out further over time -- by lowering the tax burden when the field is not producing very much oil. But in its 1984 report, ISER concluded that the ELF does not do a very good job of stretching out our revenues; in fact it only adds an additional year or two to the revenue stream. However, the report does conclude that the ELF is valuable as an incentive to explore and develop marginal fields. This is because marginal fields generally have lower production rates per well, so that the ELF significantly lowers their actual severance tax burden. These conclusions suggest that further consideration of the ELF's impact on revenues and production is warranted and that it should be looked at on an individual field basis since it may encourage production where there otherwise might not be any, such as in a marginal field, but may not have its intended effect on a very profitable field, such as Prudhoe Bay. (Another chapter of this report deals specifically with this problem and proposes one solution to it.)

X. How does the decline of Prudhoe Bay affect our revenues?

A. Prudhoe Bay production to date far outweighs production from any other field in Alaska. The ISER study shows that of the 3.6 billion barrels of oil produced in Alaska from 1959 to 1983, about 3.2 billion of those barrels -- or 90.3% came out of Prudhoe even though the field did not start production until 1977. ISER also forecast production in the future and found a similar pattern. Using ISER's base case assumptions (real wellhead price of $17.50 per barrel, declining TAPS tariff, and no change in the federal or state tax structure), of the 8.9 billion barrels likely to be produced between 1983 and 2010, about 6.9 billion -- or 79.4% -- will come from Prudhoe. These figures show that the Prudhoe Bay field is extremely important to Alaska's revenue stability. One draws the same conclusion from the following chart, which depicts production for FY85 through FY98.



B. As Prudhoe declines then, so do our revenues. What is perhaps less apparent is that analysis of future oil production shows that <u>even if all the currently known marginal fields are developed, their combined production cannot make up for the decline of Prudhoe. Lease, tax, and other revenue from development of these fields will not come close to providing Alaska with the wealth it now receives from Prudhoe Bay</u>. As Kay Brown, Director of the Division of Oil & Gas stated to the Permanent Fund trustees, "[B]ased on current knowledge, it is unlikely that new oil and gas discoveries from state lands alone will be sufficient to offset the decline in the main Prudhoe Reservoir. Most of the remaining best prospects appear to be in federal waters and perhaps in the Arctic National Wildlife Refuge." The Division of Oil &

Gas estimates that about 62% of recoverable state reserves in Alaska are in the Sadlerochit (Prudhoe Bay) reservoir.

C. The importance of Prudhoe to our revenue stability should be a driving force in determining the future of Alaska's oil and gas tax structure. It is certainly a valid public policy goal to tax the tremendous profits of Prudhoe Bay. Policy makers should not forget that revenue from production in new fields is not going to make up for the loss of Prudhoe Bay revenues. The $24 billion in profits that the companies took out of Alaska in the last four years is gone forever; it would be a mistake to continue encouraging them to take their money elsewhere.

D. Although much of Alaska's oil reserves lie off shore, development of these resources will not be a panacea for the decline of Prudhoe, either. These resources are owned by the federal government and therefore, most tax and other revenue benefits will flow back to the feds, not to the state. The only taxes that the state will get are property taxes from onshore facilities. It will not get any lease payments (except from 3-6 miles offshore if President Reagan approves a bill that may be taken up again by Congress in early 1986).

XI. Should any additional changes to the tax code be considered?

A. Ideally, the Alaskan tax code will provide revenue stability to the state even when market forces bring about lower oil prices and even when the quantity of oil in Alaska that can be taxed diminishes. Measuring price and quantity sensitivity is not easy, however.

B. Section VI discusses the fact that separate accounting is a better incentive for exploration and development than modified apportionment because it only requires the payment of taxes when a field is profitable. Many economists believe that a state can facilitate exploration and development of marginal oil fields if it increases the reliance on income taxes and decreases the reliance on severance taxes in the marginal fields. In other words, the state should consider emphasizing taxation of net income instead of gross income in marginal fields. For this reason, Professor Berman concludes that, for marginal fields, net income taxes and net profit shares in leases are superior to excise (such as severance) taxes and royalty shares in leases because a company shares profit with government, not income that just covers expenses. Although 1986 may not be the appropriate time to consider a complete overhaul of our tax and leasing policies, some comprehensive changes may eventually be desirable.

XII. What is the current status of ARCO v. State?

A. The Alaska Supreme Court ruled unanimously in the state's favor on August 16, 1985. The decision fully supported the state's position that separate accounting is constitutional in every respect.

B. In fact, the Supreme Court went even farther than it had to in upholding the lower court's decision. Instead of stating that separate accounting was an acceptable method of tax accounting, it stated that, for Alaska, separate accounting is preferable to formula apportionment. (See section V for further details.)

C. The oil companies declined to petition the Alaska Supreme Court for a rehearing of the case. In November, 1985 they appealed the decision to the US Supreme Court. The justices declined to take the case on January 13, 1986, thus ending the lawsuit.

D. Though the industry challenged the use of separate accounting in Alaska, it has argued strenuously to be allowed to use it in other states. In at least two states, Wisconsin and South Carolina, the industry took their arguments to the top levels of the court system -- to the state supreme court in South Carolina and to the US Supreme Court in the Wisconsin case. Also, before Prudhoe Bay was in the production stage, the industry tried to file separate accounting returns in Alaska. This demonstrates that the industry is interested in separate accounting when it lowers its tax burden; in other words, when its operations in a state are less profitable than the industry average.

XIII. Was there a conspiracy in 1981?

A. It has been suggested that the oil companies and the Department of Revenue conspired to convince the legislature to enact amendments in 1981 that substantially lowered our fair share of Alaskan oil wealth. Although this point of view is strengthened by the fact that the 1981 amendments now appear to have cost the state about $850 million, an analysis prepared by OMB suggests that there probably was no conspiracy. The fiscal information provided by the companies to the department, which in turn was used to prepare the legislation's fiscal note, has turned out to be wrong. But it does not appear likely that wrong information was intentionally provided. According to Gregg Erickson, Senior Economist at OMB, "I know of no evidence which would positively rule out the possibility that this discrepancy resulted from an effort to mislead; ... a more plausible explanation is that the oil company experts simply goofed."

B. Although the above information is interesting, what did or did not happen in 1981 should not be the motivation for a return to our pre-81 tax structure. Rather, the motivating forces should be such aspects of HB 353 as the superiority of separate accounting as evidenced by the recent court ruling, its incentives for exploration and development, and the goal of restoring Alaska's fair share of the wealth created by our abundant oil. In this context it is interesting to note that when the legislature enacted the 1981 changes, it did not repeal the findings section of the original 1978 statute which stated the superiority of separate accounting over an apportionment method.

XIV. Is the oil industry healthy?

A. It would certainly appear that Exxon is healthy. A recent Business Week article made the following observations: "The only surplus at Exxon Corp. is a surplus of cash. ... The bottom line is that Exxon can make a nice living even if the price of oil falls quite a bit more. ... Salomon Bros. estimates that Exxon will have as much as $7 billion in spare cash to spend through 1988. ...In fact, Exxon's real limitation is not a lack of money but of enough places in which to invest it profitably." Because prices are down right now, Exxon is frugal with investments and cautious about the future. But it is hardly suffering and couldn't be accurately characterized as anything but very healthy.

B. The legislature commissioned a report by Tanzer Economic Associates, Inc. in 1977. Among other things, the report examined many historical examples of tax changes throughout the world. It concluded that "there is one effect almost invariably caused by such tax changes. Namely, an almost automatic reaction of the oil companies to claim that such increased taxation will force them to look elsewhere for increased future production. These claims are sometimes backed up by actions, aimed at getting the country to rescind the tax increase, such as temporarily cutting present production or reducing exploration and development efforts. ...Some of the actions and much of the rhetoric ... is 'theater', aimed at improving a bargaining position, and often needs to be taken with a very large grain of salt." One can infer from this observation that the industry will often exaggerate how it will be affected by a tax change in order to keep the change from occurring.

C. In 1985, the industry uses the current production surplus and price decline pattern as justification for laying off hundreds of Alaskans and cutting daily rates paid to the various oil industry support companies that operate on the Slope. Not surprisingly, it also comes to Juneau and complains bitterly about HB 353, implying that the bill is forcing it to cut back and to consider leaving Alaska. Industry testimony is difficult to accept since we know it is not leaving Alaska, with our Prudhoe bonanza and our undeveloped reserves, and since we know that HB 353 provides the proper incentives to stay. It becomes even harder to accept when one considers the major factor that explains the majors' current restructuring efforts. Because of falling world oil prices, the fear of takeover is prevalent in industry thinking and the desire to cut costs to a minimum is really motivated by the need to have enough cash around to prohibit an unfriendly takeover (or in the case of some majors, to acquire less healthy companies). Furthermore, declining oil prices is a major factor inthe majors' cut backs in exploration activity.

XV. How does taxation of the industry in Alaska compare to taxation in other states and at the federal level?

A. Of the top five oil producing states -- Alaska, California, Texas, Oklahoma and Louisiana, two currently require the use of separate accounting to determine income derived from oil production. These states are Louisiana and Oklahoma. California utilizes formula apportionment and Texas does not have a corporate income tax. (Actually California does require separate accounting in cases where formula apportionment under represents income generation within the state.) In addition, the United States government requires the use of separate accounting in certain instances. Moreover, President Reagan has recently taken an active stance against formula apportionment based on worldwide combination. Since apportionment taxes a portion of a company's worldwide income, some important US trading partners oppose it because they feel that American states take tax dollars away from them. Thus, Reagan has asked Congress to prohibit the use of this kind of formula apportionment at the state level.

B. Another way to compare taxation of the industry in Alaska to industry taxation elsewhere is to compare how much is collected by states from the whole tax code and leasing structure, not just the income tax. The ISER study compared tax and leasing policies in Alaska to such policies in Texas and concluded that "... Alaska and Texas collected approximately the same amount of revenue from oil and gas production." This is interesting because the tax and leasing structure in Texas and Alaska are very different yet, essentially, industry is treated the same. Alaska should not be judged by whether it has a separate accounting or a formula apportionment based income tax but rather by how its policies as a whole impact the oil industry.

XVI. Conclusion

A. HB 353 is well constructed tax reform legislation. It is an attempt to restore Alaska's fair share of the oil wealth to provide Alaskans with desired public services, provide an atmosphere that encourages the oil industry to remain in Alaska, and return Alaska's tax structure to the exhaustively studied and carefully refined one that existed before it was challenged by the oil companies in the late 1970s.

III.

THE SEVERANCE TAX AND THE ECONOMIC LIMIT FACTOR

I. Introduction

It is generally known that oil producers in Alaska are assessed severance tax rates of 12.25 or 15 percent. However, it may not be so well known that the actual tax rates they pay are much lower than this because of the economic limit factor or ELF. (A severance tax or production tax is a flat tax based solely on the amount produced; in contrast, an income tax is based on profits.)

The ELF is a statutory reduction to the severance tax. It was adopted in 1977[1] to promote production on oil and gas fields with low output and presumably little profit. As the cost of producing the oil gets closer to its value -- the economic limit -- the ELF reduces the tax that is owed. When a field reaches the economic limit the ELF reduces the severance tax to 0. The ELF is applied to both oil and gas, but this discussion deals only with oil.

In practical terms, the ELF dramatically reduces the state's base severance tax rates of 12.25% or 15% on all fields. Prudhoe Bay is a temporary exception to this

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[1]In anticipation of North Slope production, the Department of Revenue recommended the ELF in its exhaustive 1977 study: "Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement." Previously a "stair-step" approach to severance taxes was used, keyed to Cook Inlet production, with graduated rates to 8 percent. The ELF improved upon the stair steps, retaining the idea that the tax should be reduced as production declined. The ELF also was able to adjust tax rates for both high-volume North Slope fields and the lower-volume Cook Inlet fields.

because of a provision that suspends the ELF for 10 years on high volume fields. However, in FY 88 the 10-year limit expires and Prudhoe will also enjoy tax concessions of the ELF -- and the state will lose $156 million, according to OMB calculations (see Attachment A). Another example is Kuparuk. In FY 86 the ELF reduced Kuparuk's effective severance tax rate to 6%, and the state lost $58 million.

An unforeseen consequence of the ELF is that it will greatly reduce the severance tax rates on most of the fields that have yet to begin producing. For example, in FY 90 the effective severance tax rate for Lisburne will be 3% and for Endicott it will be 4%. These cases show that the ELF is actually providing these marginal fields with a substantial incentive -- reducing costs at field start-up.

The ELF's original goal was to extend the life of fields, and thus extend revenues to the state. However, one study shows that the ELF only prolongs a field's life for one or two years, thus its direct benefit to the state is limited. Nonetheless, the ELF does appear to provide an incentive to developers of marginal fields because it reduces the severance tax rate. If the ELF were eliminated, for example, it is likely that some of the marginal fields would not be feasible to develop.[2]

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[2] In a study entitled "Alaska North Slope Oil Production and Revenue Projections" published Feb. 1985 by the Institute of Social and Economic Research, author and UAA economist Matthew Berman concluded that the Endicott and Milne Point fields might not be feasible to develop without the ELF.

It's also apparent that fields with substantial output and correspondingly high profit rates, such as Prudhoe and Kuparuk, do not require the production incentive that the ELF provides.

II. How the ELF Works

The ELF is a formula that is multiplied by the nominal rate of 12.25% or 15% to obtain the effective rate actually applied to a field. The ELF will never be more than 1. If the ELF is 1, then 100% of the severance tax is owed. An ELF of .8 means 80% of the tax is owed; 80% of 15% equals an effective tax rate of 12%.

Since 1981 the severance tax rate has been 15%, with an exception for new fields; fields that start producing after June 30, 1981 pay a reduced rate of 12.25% for the first five years. The law also requires that the ELF be calculated at 1 during the first 10 years of a field's production any time the ELF goes above .7. (Currently this provision only affects Prudhoe.) For fields with an ELF at or below .7, the actual ELF used. After 10 years the actual ELF is used in all cases.

For example, the ELF for Prudhoe Bay in FY 85 was .864 Since this is more than .7 and within the first 10 years of production, the 1 figure is used. Thus the full 15% severance tax was owed.

In FY 88, however, the 10-year limit will no longer be in effect for Prudhoe (production began in FY 78) and the actual ELF of .82 will be used. This means the amount of severance tax owed will be 82% of 15%, or an effective rate of 12.5%. The amount to be paid to the state will be $714 million, $156 million less than if the full 15% severance tax were paid.

III. Modifying the ELF

It is apparent that the ELF accomplishes its goals but not without some drawbacks. One drawback is providing and unnecessary tax reduction for Prudhoe and Kuparuk. Another issue is whether it goes far enough in reducing the severance tax rate on marginal fields. (A problem with a severance tax as opposed to an income tax is that it is not sensitive to profits or costs, thus a fair tax rate for a large field may be a burden for a small field.)

An additional problem with the current ELF formula is that it is based on daily output per well; total field production is not taken into account. This penalizes a marginal field like Milne Point (30,000 bbls/day) which has high output per well but few wells (about 22). Under the current ELF formula Milne is subject to a severance tax rate almost as high as the tax applied to Kuparuk (240,000 bbls/day), which is clearly not a marginal field. For example, in FY 88, Milne Point will be paying a 7.35% severance tax compared to Kuparuk's rate of 7.6%.

Instead of basing the ELF on individual wells, total field production could be included in the ELF formula to compensate for this inequity, keeping the severance tax low on the smaller fields that would benefit most from a tax break.

The ELF could be modified to accomplish these goals:

-- Dramatically reduce the effective severance tax rates for all marginal fields, including Cook Inlet.

-- Prevent a premature reduction to the severance tax rates for Prudhoe and Kuparuk. These highly profitable fields are years away from being marginal. When they do start approaching the economic limit, the ELF formula will provide them with a tax break.

-- More equitably set the tax rate for each field.

This formula modification would bring Prudhoe's ELF to .99 (now it is at .83); raise Kuparuk's to .8 and drop Milne Point's to .3. These ELFs translate into effective severance tax rates of about 14.85%, 12% and 4.5%.

Here are the current ELFs compared with ELFs under the revised formula.

	Current ELF	Modified ELF	% change
Prudhoe Bay	.80	.99	+23
Kuparuk	.50	.86	+72
Milne Point	.60	.31	-48
Endicott	.31	.0	-100
Lisburne	.11	.05	-54
West Sak	.0	.0	no change
Cook Inlet	.03	.0	-100

The formula change would result in the following positive state severance tax collections*:

FY	millions
87	$ 32
88	179
89	192
90	184
91	175
92	173
93	170
94	158

* These numbers, based on June 1985 revenue projections, assume the actual ELF is used in all cases and assume a 15% severance tax rate across the board. (If the 12.25% for the first 5 years were retained, there would be little change in these amounts.)

IV. What Legislation Would Require

1) Simplify the law so the actual ELF is always applied. Current law requires that an ELF of 1 be used if the actual ELF goes above .7 any time during the first 10 years of a field's production. (AS 43.55.013)

2) Change the ELF formula. (AS 43.55.013) This modification only alters the exponent part of the formula. It uses a different number as a constant and takes into account average daily production from the whole field.

Current ELF formula:

$$\text{ELF} = \left(1 - \frac{\text{PEL}}{\text{TP}}\right) \exp\left(\frac{460\text{xWD}}{\text{PEL}}\right)$$

Revised ELF formula:

$$\text{ELF} = \left(1 - \frac{\text{PEL}}{\text{TP}}\right) \exp\left(\frac{37{,}000{,}000\text{xWD}}{\text{PELxTP/Days}}\right)$$

PEL = monthly production rate at the economic limit (300 barrels x number of well days a month)
TP = total production (number of barrels) during the month
WD = well days in the month
exp = the expression following this is an exponent
Days = The number of days in the month for which the tax is to be paid

The numbers 460 and 37,000,000 are constants or scaling factors.

V. Conclusion

Enacting these changes to the severance tax would not only maintain our current level of severance tax revenue. More importantly, the revised ELF would provide a new incentive for future oil exploration and production in Alaska by lowering the severance tax on marginal fields.

ALASKA NORTH SLOPE OIL AND GAS REVENUES

Alaska North Slope Oil Revenue

	Fiscal Years									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
June 1985 Pet. Rev. Assumptions										
World Oil Price	26.37	24.81	22.41	22.286	22.733	23.464	24.362	25.565	26.934	28.379
Average Rate of Inflation	4.83	3.92	4.81	4.76	4.76	4.76	4.76	4.76	5.184	5.184
ANS/World Qual.& Marketing Adjust	3.253	2.532	2.663	2.639	2.384	2.447	2.475	2.528	2.587	2.612
TransAlaska Pipeline Tariff	6.087	6.087	6.087	6.087	6.087	6.087	6.087	6.087	6.087	6.087
ANS Netback Price PS01 ($/bbl)	17.11	15.471	13.74	13.56	14.34	15.81	15.88	17.83	18.34	19.76
Prudhoe Bay Prod.(MMbbl/d)	1.528	1.517	1.500	1.34	1.188	1.03	.874	.815	.753	.641
Prudhoe Bay Price ($/bbl)	17.11	15.471	13.74	13.56	14.34	15.81	15.88	17.83	18.34	19.76
Wells	468.25	509.6	527.1	548.6	524.85	505.15	489.9	466.45	447.65	428.65
ELF	.8648307	.8496946	.8437062	.8205208	.8041141	.7834653	.7540433	.7491265	.7399201	.7145822
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.15	.15	.15	.1230793	.1206171	.1175198	.1131065	.1123698	.1109892	.1071753
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	1252.465	1124.336	992.6137	714.2504	656.2593	588.2696	501.3609	490.1035	489.5263	433.9515
SEVERANCE TAX (NO ELF)	1252.465	1124.336	992.6137	870.4757	816.1270	748.6458	664.8966	664.9124	561.5863	606.7882
CONSERVATION TAX	.6180063	.6056148	.6020219	.5349531	.4742719	.4111953	.3489172	.3253633	.3866117	.2558992
Gathering & Cleaning Charge	.7	.72821	.7567558	.7871817	.8245678	.8638172	.9049349	.9480898	.9931351	1.044619
ROYALTIES	1144.823	1028.395	893.2797	788.9031	732.5782	664.7822	597.1494	597.9988	595.9624	547.3418
TOTAL OIL PROD REVENUES	2396.488	2144.731	1885.893	1495.153	1388.829	1245.052	1090.518	1096.102	1085.489	988.8945
Kuparuk River Prod.(MMbbl/d)	.167	.2	.219	.239	.239	.239	.21	.187	.162	.141
Kuparuk River Price ($/bbl)	16.29	14.651	12.92	12.74	13.52	14.39	15.86	16.21	17.52	18.94
Wells	154.5	248.5	284	285.25	285.25	285.25	276.5	276.5	254	254
ELF	.69	.4891136	.4697785	.5867938	.5867938	.5867938	.4627634	.4878192	.3773622	.3312742
Nominal Tax Rate	.1225	.1225	.1363	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	.084525	.0599164	.0640297	.0760191	.0760191	.0760191	.0694145	.0610529	.0566043	.0466911
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	73.43048	56.87173	57.86143	73.92490	78.45892	82.33865	78.11249	59.10602	51.30973	48.38790
SEVERANCE TAX (NO ELF)	106.4326	114.6395	123.1696	145.8678	154.7985	162.4697	151.5803	145.2168	135.9694	129.7582
CONSERVATION TAX	.0666695	.0798438	.0874209	.0954133	.0954133	.0954133	.0838359	.0746539	.0646734	.0578883
Gathering & Cleaning Charge	.4	.4005	.4010006	.4015019	.4020038	.4025063	.4030094	.4035132	.4040175	.4045226
ROYALTIES	121.0719	138.0358	125.8883	134.5436	143.8436	150.3448	148.4323	134.8598	126.5885	128.9324
TOTAL OIL PROD REVENUES	194.5103	186.1875	182.9497	209.4685	221.4945	232.6827	218.5448	193.9658	177.0182	161.3203
Milne Point Prod.(MMbbl/d)	0	0	.008	.023	.023	.023	.023	.023	.018	.016
Milne Point Price ($/bbl)	17.48	15.841	14.11	13.93	14.71	15.38	16.25	17.4	18.71	20.13
Wells	1	1	21.15	21.15	21.15	21.15	21.15	19.6	17.1	15.6
ELF	0	0	.8892801	.6896111	.6896111	.6896111	.6896111	.6159828	.5978649	.5882759
Nominal Tax Rate	.15	.15	.15	.15	.15	.15	.15	.15	.15	.15
Effective Tax Rate	0	0	.0133928	.0914417	.0914417	.0914417	.0914417	.0951851	.0896797	.0882414
Royalty Percentage	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625	.1625
SEVERANCE TAX (ELF)	0	0	.4621848	8.955726	9.457195	9.887944	10.44728	11.66967	9.233479	8.687879
SEVERANCE TAX (NO ELF)	0	0	5.175901	14.69808	15.51349	16.23808	17.13761	18.35842	15.44242	14.76837

	1985	86	87	88	89	90	91	92	93	94
Gathering & Cleaning Charge	0	0	0	0	0					
ROYALTIES	0		0	6.695195	19.00111	20.06720	20.90170	22.16065	21.71606	19.97526	19.10337
TOTAL OIL PROD REVENUES	0		0	7.157300	27.95006	29.52439	30.06915	34.61532	35.40593	29.30774	27.79125
Endicott Prod.(MMbbl/d)	0	0	0	.019	.063	.065	.067	.069	.07	.056
Endicott Price ($/bbl)	15.99	14.351	12.62	12.44	13.22	13.89	14.76	15.91	17.22	18.64
Wells	1	1	1	34.5	111.5	111.5	111.5	111.5	111.5	100.05
ELF	0	0	0	.2992290	.3132327	.3301150	.3462700	.3617316	.3692130	.3000971
Nominal Tax Rate	0	0	0	0	0	.1225	.1225	.1225	.1225	.1225
Effective Tax Rate	0	0	0	0	0	.0404392	.0424181	.0443121	.0452207	.0377019
Royalty Percentage	.1430	.1430	.1430	.1430	.1430	.1430	.1430	.1430	.1430	.1430
SEVERANCE TAX (ELF)	0	0	0	0	0	11.41001	13.10932	15.20232	17.03779	12.31192
SEVERANCE TAX (NO ELF)	0	0	0	0	0	34.56366	37.85067	42.02652	46.14614	39.96116
CONSERVATION TAX	0	0	0	.0074222	.0246104	.0253917	.0261730	.0269542	.0273449	.0210759
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	12.40583	43.71432	47.30789	51.90544	57.61970	61.26783	54.70003
TOTAL OIL PROD REVENUES	0	0	0	12.40583	43.71432	50.79790	65.01476	72.82202	80.30562	67.09995
Lisburne Prod.(MMbbl/d)	0	0	.009	.017	.041	.061	.074	.075	.076	.078
Lisburne Price ($/bbl)	16.04	15.201	13.47	13.29	14.07	14.74	15.61	16.76	18.07	19.49
Wells	1	1	79.5	79.5	104.25	116.9	116.9	116.9	116.9	116.9
ELF	0	0	0	0	.1101111	.2693556	.3734920	.3803931	.3871543	.4002726
Nominal Tax Rate	0	.1225	.1225	.1225	.1225	.1225	.15	.15	.15	.15
Effective Tax Rate	0	0	0	0	.0134806	.0329961	.0564239	.0570590	.0580731	.0600409
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	2.405111	9.475243	20.66840	22.90657	25.47112	29.15107
SEVERANCE TAX (NO ELF)	0	0	4.742934	8.039150	22.56914	35.17745	55.33043	60.21016	65.79061	72.02004
CONSERVATION TAX	0	0	.0035930	.0067867	.0163680	.0243523	.0295422	.0299414	.0303406	.0311391
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	5.531119	10.30006	26.31969	41.02326	52.70326	57.35063	62.65771	69.36004
TOTAL OIL PROD REVENUES	0	0	5.531119	10.30006	28.00401	50.49051	73.37174	80.25719	88.12804	98.51110
West Sak Sands Prod.(MMbbl/d)	0	0	0	.022	.03	.044	.05	.055	.057	.062
West Sak Sands Price ($/bbl)	15.33	13.691	11.96	11.78	12.56	13.23	14.1	15.25	16.56	17.98
Wells	1	76	83.5	91	169.5	169.5	284	284	284	284
ELF	0	0	0	0	0	0	0	0	0	0
Nominal Tax Rate	0	0	0	0	.1225	.1225	.1225	.1225	.1225	.15
Effective Tax Rate	0	0	0	0	0	0	0	0	0	0
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	0	0	0	0	0	0
SEVERANCE TAX (NO ELF)	0	0	0	0	14.74171	22.77454	27.50202	32.01478	36.92948	53.40397
CONSERVATION TAX	0	0	0	.0007020	.0119766	.0175656	.0199609	.0219579	.0227555	.0247516
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	11.02418	17.1915	26.55923	32.16563	38.26797	41.06615	50.06093
TOTAL OIL PROD REVENUES	0	0	0	11.02418	17.1915	26.55923	32.16563	38.26797	41.06615	50.06093
Unspecified Onshore Prod.(MMbbl/d)	0	0	0	0	0	.018	.032	.033	.034	.035
Unspecified Onshore Price ($/bbl)	15.19	13.551	11.02	11.64	12.42	13.09	13.76	15.11	16.42	17.84
Wells	1	1	1	1	33.3	45.15	42	37.5	33	27.75
ELF	0	0	0	0	0	.1175305	.4647302	.5276955	.5899642	.6593604
Nominal Tax Rate	0	0	0	0	0	0	.1225	.1225	.1225	.1225
Effective Tax Rate	0	0	0	0	0	0	.0568682	.0646427	.0722706	.0807716
Royalty Percentage	.125	.125	.125	.125	.125	.125	.125	.125	.125	.125
SEVERANCE TAX (ELF)	0	0	0	0	0	0	8.111455	10.29435	12.00590	16.10730
SEVERANCE TAX (NO ELF)	0	0	0	0	0	0	17.47722	19.50812	21.04183	24.42067
CONSERVATION TAX	0	0	0	0	0	.0071859	.012775	.0131742	.0135734	.0139727
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	0	0	10.75016	20.1016	22.74799	25.47153	28.40825
TOTAL OIL PROD REVENUES	0	0	0	0	0	10.75016	28.49505	31.04434	38.35742	44.59555
Seal Island Prod.(MMbbl/d)	0	0	0	0	0	0	0	0	0	0
Seal Island Price ($/bbl)	15.54	13.901	12.17	11.99	12.77	13.44	14.31	15.46	16.77	18.19
Wells	1	1	1	1	1	1	1	1	1	1
ELF	0	0	0	0	0	0	0	0	0	0
Nominal Tax Rate	0	0	0	0	0	0	0	0	0	0

SEVERANCE TAX (ELF)	0	0	0	0	0	0	0	0	0	0
SEVERANCE TAX (NO ELF)	0	0	0	0	0	0	0	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
Gathering & Cleaning Charge	0	0	0	0	0	0	0	0	0	0
ROYALTIES	0	0	0	0	0	0	0	0	0	0
TOTAL OIL PROD REVENUES	0	0	0	0	0	0	0	0	0	0

NORTH SLOPE Prod. (MMbbl/d)	1.695	1.717	1.744	1.66	1.584	1.48	1.33	1.257	1.17	1.031
AVG. NORTH SLOPE PRICE ($/bbl)	17.02921	15.37548	13.63733	13.48789	14.13648	14.74674	15.57237	16.78890	18.08509	19.39853
AVG. NOMINAL TAX RATE	.1472986	.1467967	.1481377	.1460136	.1428815	.1450169	.1469192	.1465652	.1462150	.1475722
AVG. EFFECTIVE TAX RATE	.1435431	.1395869	.1370037	.1115651	.1036898	.0986285	.0934909	.0912185	.0892272	.0830136
AVG. ROYALTY PERCENTAGE	.125	.125	.1251720	.1257340	.1262922	.1264884	.1265956	.1267181	.1267817	.1266031
SEVERANCE TAX	1325.903	1180.408	1050.937	797.1311	746.6525	693.3815	623.8119	617.2910	605.4633	540.1976
CONSERVATION TAX	.6766750	.6854506	.6961806	.6621466	.6314206	.5898927	.5299927	.5008326	.4661775	.4100404
ROYALTIES	1265.095	1150.438	1030.594	968.9879	982.9865	961.0279	916.9057	932.5829	936.9096	898.0760
TOTAL OIL PROD REVENUES	2591.675	2331.524	2082.228	1766.781	1730.198	1655.799	1541.248	1550.366	1542.839	1431.404
	14.35431	13.95869	13.70037	11.15651	10.36898	9.862854	9.349886	9.121849	8.922717	8.301360

FISCAL IMPACT OF ELF REPEAL ON SEVERANCE TAX INCOME

ALL NORTH SLOPE FIELDS

	F/85	86	87	88	89	90	91	92	93	94
SEVERANCE TAX (MILLIONS OF $)										
NO ELF	1358.897	1230.976	1125.702	1039.874	1023.750	1011.858	971.7988	983.0472	983.7061	941.9207
WITH ELF	1325.903	1180.408	1050.937	797.1311	746.6525	693.3815	623.8119	617.2818	605.4633	540.1976
REVENUES RESULTING FROM										
REPEAL OF ELF	32.99410	50.56776	74.76406	242.7425	277.0974	318.[illegible]90	347.9870	365.7653	378.2428	401.7311
CUMULATIVE TOTAL	32.99410	83.56186	166.3267	409.0693	686.1667	1004.636	1352.623	1718.388	2096.631	2498.362

PRUDHOE BAY ONLY

SEVERANCE TAX (MILLIONS OF $)										
NO ELF	1252.465	1124.336	992.6137	870.4757	816.1270	740.6450	664.8966	664.9124	661.5863	606.7882
WITH ELF	1252.465	1124.336	992.6137	714.2504	656.2593	580.2696	501.3609	498.1035	489.5263	433.5515
REVENUES RESULTING FROM										
REPEAL OF ELF	0	0	0	156.2253	159.8678	160.3754	163.5357	166.8089	172.0600	173.2367
CUMULATIVE TOTAL	0	0	0	156.2253	316.0931	476.4685	640.0042	806.8131	978.8730	1152.110

Figures calculated by OMB

IV.

MAJOR LITIGATION

WITH THE OIL AND GAS INDUSTRY

A. Introduction

Alaska is currently involved in one of the largest litigation efforts in U.S. history. The amounts at issue in the state's oil and gas litigation total at least $15 to $20 billion. This section of the report focuses on two of the most important disputes with the oil and gas industry, both of which have to do with a single concern: the value of North Slope oil at the point it enters the pipeline. This is referred to as the wellhead value, and the state's tax revenue and royalty value are based on it. The State v. Amerada Hess case is a dispute over the value of the state's royalty oil; the Trans Alaska Pipeline Rate Case addresses proper pipeline tariffs. Both cases involve all the major oil producers and are characterized by their complexity and the enormous effort required to litigate them successfully.

B. The Process of Valuing North Slope Oil

Putting a price on North Slope oil is difficult because unlike oil produced in the Lower 48, most North Slope oil is not sold at the wellhead but rather far from its source, most often on the West Coast or Gulf Coast. Another complication is that much of the oil is refined by the producers themselves, so there are internal transfers within one company rather than third-party sales. In addition, many third-party sales are often done by exchanges with other considerations rather than a simple price. Thus the value of the oil at those distant markets is not a clearcut issue, and the state contends the producers significantly understate the value of the oil when it reaches its ultimate destinations.

It is important to determine the wellhead value of North Slope oil, however, because it is at this point where the state determines the value of its royalty share and levies the severance tax. The federal government also sets the windfall profits tax at the wellhead.

Thus the value of the oil is determined by the process called netback. To arrive at netback, a destination price is set for the oil (by the oil companies) and then the costs of transportation -- primarily pipeline and tanker -- are subtracted. All three of these values, destination price, tanker costs, and pipeline tariffs, are not easy to determine and thus are the subject of litigation. It is usually to the benefit of the producers to keep transportation costs high in order to keep the wellhead price down and thus reduce the royalties and severance taxes they owe the state.

Compounding the difficulty of valuing North Slope oil is the fact that the producers, notably the three major North Slope producers, Arco, Exxon and Sohio, have different netback methods. They use different methods to set the destination price, different methods to determine tanker transportation costs and different methods of setting the pipeline tariff. Furthermore, a company's valuation methods may change from month to month. Some months the state may agree with a particular company's figures; another month, it may disapprove of the same company's figures.

The destination price and tanker transportation costs are currently the subject of multi-million dollar litigation over the value of the state's royalty oil. The State v. Amerada Hess case is a dispute over the proper value to be attributed to crude oil when it reaches the Lower 48 and the proper deductions to be made for tanker transportation. (Similar issues are involved in the company's severance tax disputes with the state, but with this case the royalty contracts are at issue.) The TAPS tariff case addresses the third major area of dispute, proper pipeline charges.

C. State v. Amerada Hess

The amounts at issue in this case for both past and future royalties is probably upwards of $2 billion in present day dollars.

In general, Alaska's position is that the value of the oil should be higher for West Coast destinations than for Gulf or East Coast destinations (because transportation costs to the West Coast are lower). Some companies agree with this premise but disagree with the actual prices, while other companies disagree with this approach altogether.

While it is not easy to get information on the record on the specifics of the valuation disputes, federal hearings[1] in early 1983 over the windfall profits tax reveal how the major producers value their North Slope oil. The hearings focused in particular on the method used by Arco.

Arco sets a single price for North Slope oil regardless of its destination. The price is based on West Texas sour, an oil comparable in quality to ANS crude and actively traded in the Gulf. Transportation costs to the Gulf Coast are then deducted to arrive at a wellhead value for all its North Slope oil. Thus Arco is valuing all of its oil as though it were sent to the Gulf Coast (it costs roughly $4 more to transport oil to the Gulf). This pricing method has merit in theory, but was severely criticized during the hearings because in fact, Arco sells 70% of its oil on the West Coast. From Alaska's and the federal government's perspective, Arco is artificially setting its West Coast price too low and thus avoiding paying millions of dollars in taxes and royalties.

The oil companies again explained their valuation methods to the Alaska Senate Resources Committee in late

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[1]The hearings on the windfall profits tax were held in February 1983 before the House of Representatives Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce.

1983.[2] One of the points made then was that Alaska prefers Sohio's valuation method. Sohio, which doesn't own refineries on the West Coast or in the Gulf, determines value for North Slope crude by finding out how much refiners would pay for comparable foreign crude. Sohio also adjusts it price for destination.

The disparity between the companies' valuation methods results in strikingly different wellhead values. For example, Arco's West Coast price averaged about $2.50 per barrel less than Sohio's throughout 1984. For 1985, Arco's price avera[illegible] out $1.50 less.

The transportation part of the dispute is complicated by the fact that some producers own their own tankers while others charter tankers. For example, Arco owns about 70 percent of its tankers; Sohio owns none and charters U.S. flagships; Exxon charters about 70 percent of its tankers.

Sohio deducts the actual costs it is charged, while Arco deducts costs based on a national shipping standard called U.S. Freight Rate Averages. Other producers that own their own tankers deduct actual costs of operation and capital investment. Yet another variable for those who charter tankers is whether to use long-term or short-term rates. According to company figures supplied to the federal government, 1982 shipping charges ranged from .78

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[2]The commitee held hearings in September 1983 on oil and gas issues.

to 2.35 a barrel for West Coast deliveries, and from 4.29 to 6.63 for Gulf/East Coast deliveries.

In late 1984 the U.S. General Accounting Office[3] drew the following profiles of the major North Slope producers based on information obtained from the windfall profits tax hearings. (While the figures are based on 1982 production, the methods and amounts are still fairly representative today.)

SOHIO

Sohio has no refineries on either the West or Gulf coasts. Thus the company either sells or exchanges all of its North Slope oil, about 597,000 barrels daily in 1982. About 40 percent of Sohio's North Slope oil went to the West Coast, about 60 percent went to the Gulf Coast and Caribbean.

For each of these market areas, Sohio negotiates a selling price for North Slope oil based on prices customers would pay for competing imported crude oils, with what the company considers appropriate adjustments for differences in oil quality.

Sohio transports its North Slope oil in charted US-flag tankers operated by contract with outside parties. From the value received from those arm's-length, third-party transactions in each geographic area, Sohio deducts the pipeline tariff and waterborne and other transportation costs to establish wellhead price in Alaska.

ARCO

Arco uses most of its North Slope crude in its own refineries. In 1982, about 70 percent of Arco's 340,000 barrels per day went to the company's West Coast refinery at Los Angeles. Arco sold an additional 25,000 barrels on the West Coast. The remainder of Arco's North Slope oil, 50,000 to 75,000 barrels, went to the Gulf Coast.

Arco establishes a single wellhead price for its North Slope oil, regardless of its destination. Arco sets its price in the Gulf Coast, based on West Texas sour which is actively traded in the area. From this market price, Arco deducts pipeline tariffs and waterborne costs to the Gulf Coast. The resulting price is the wellhead value for both West Coast and Gulf Coast deliveries.

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[3]The GAO report entitled "Response to Questions About the Windfall Profit Tax on Alaskan North Slope Crude Oil" was published in December 1984.

About 70 percent of Arco's North Slope production is transported in company-owned ships. For these ships Arco deducts U.S. Freight Rate Averages as costs. Actual charges are used for shipments on chartered vessels.

EXXON

In 1982 Exxon produced about 325,000 barrels a day and used about 94 percent of North Slope oil in its own refineries. About one third of its production went to the West Coast, about two-thirds went to its Gulf and East Coast refineries.

Exxon's general approach to pricing recognizes the West and Gulf/East Coasts as separate marketing areas. Exxon's assessment of market value is based on factors such as its own commercial transactions and posted prices of domestic crudes in the area as adjusted for quality. Then Exxon deducts transportation costs to arrive at netback value. These netback values are then averaged by volume shipped to each market area to arrive at wellhead value.

About 70 percent of Exxon's marine transportation is by U.S. chartered tankers.

The Amerada Hess case will require the state to make a detailed factual review of all West Coast and Gulf Coast oil marketing transactions for a seven-year period. The state will have to track the disposition of billions of barrels of North Slope oil. Fiscal years 1986 and 1987 will be peak years of activity for this case, which is currently in the stage of preliminary discovery.

D. <u>The Trans Alaska Pipeline Rate Case</u>

This is the case which has received the most intense litigation effort at this point. The amounts at issue between the best case and worst case outcomes, over the life of the field, are approximately $7 to $10 billion.

Ever since start-up of the Trans Alaska Pipeline System (TAPS) in 1977, the state and the pipeline owners have been in litigation over how much the tariff should be. The pipeline tariff -- the per barrel amount TAPS owners charge for transporting oil through the pipeline -- affects the wellhead value of North Slope oil. The higher the tariff, the lower the wellhead price and the less the state collects in royalties and severance taxes. The state and others say the tariff is too high. (The prevailing tariff charges have ranged from about $5.60 to $6.40 per barrel.)

Last summer the state and six of the eight TAPS owners signed a settlement which affects tariffs through 2011; the Federal Energy Regulatory Commission subsequently approved the settlement which is now in effect. The remaining issue is whether to include the other pipeline owners, Sohio and Amerada Hess, in the settlement. After consulting with legislators and state officials in December, the governor decided to give the companies until February 12 to voluntarily join the settlement. If they don't, the state will continue litigation. However, FERC still has the option of imposing the settlement on the companies.

The settlement has had an immediate impact on state revenues, providing a welcome cushion against declining world oil prices. The increase in revenues is due to lower tariffs and therefore higher wellhead values. This TAPS money[4] has already been incorporated into current revenue forecasts and increased the forecasts by these amounts:

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[4]These amounts are what could be termed net gain to the state's unrestricted revenues. The law requires that 25 percent of royalties be put into the Permanent Fund, so the net amount is what is left over after the Permanent Fund contributions.

FY 86	$ 59.2 million
FY 87	156.9 million
FY 88	136.6 million

The Department of Revenue estimates the settlement will bring from $120 to $150 million each year to the state until 1992 and then the amounts will decline. In the late 1990s, the tariffs will start rising and revenues to the state will accordingly decrease.

In addition to the above amounts, the state expects to receive another $120 million in refunds and legal expense reimbursements. This money has not yet been added to the current revenue projections. If Sohio signs the settlement, the state would receive an additional $70-$75 million in refunds. On the other hand, if litigation continues, the state may ultimately receive more money, although litigation always has its risks and resolution could be years away. It's hard to predict at this point if an eight-company settlement will ultimately occur.

FERC's decision approving the six-company settlement has been appealed by the Arctic Slope Regional Corporation and the Alaska Public Interest Research Group (AKPIRG). If an appeal is successful, FERC will hold more hearings.

This is the second attempt in more than eight years of litigation to settle the case. The 1982 effort failed, and the legislature decided to continue litigition to obtain two goals: to establish a rate-making methodology to last through the century, and to establish a methodology that would aid further oil development on the North Slope (meaning lower tariffs in the 1990s). Litigation has been expensive. The Department of Law has spent over $36 million on this case alone, not including in-house costs.

The settlement has been highly controversial, drawing fire from several quarters. Last summer the House Majority Leader hired independent economist Jamie Love to analyze the settlement. Love concluded the state gave away too much when it exchanged its litigation position for the settlement. According to Love's calculations, the settlement means the state will lose from $5.2 to $6.4 billion through the life of the settlement -- an amount that would be collected if the state's litigation position were to prevail. According to Department of Law figures, however, the settlement means an overall loss of $2.5 billion (over the life of the settlement) when compared with the state's litigation position. The settlement is also a $4.5 billion gain when compared with the TAPS owners' litigation position.

Bob Maynard, the assistant attorney general who's handling the TAPS case for the state, says Love made some big errors and used wrong assumptions in his report. Memos from attorneys working on the case to the Department of Law said Love's conclusions shouldn't be the basis of any policy. Maynard also pointed out that the settlement is a compromise which necessarily means the state gets less than if its litigation position were to prevail.

The Alaska Public Utilities Commission also did its own in-house analysis of the settlement late last year and concluded the settlement is not in the public's best interest and may have an adverse effect on oil exploration and production on the North Slope. APUC thinks the settlement does not adequately balance the competing interests of past, present and future shippers, carriers, producers, royalty owners, the state of Alaska and the federal government. It also shares Arctic Slope Regional Corporation's concern that the rising tariffs at the end of the century will prevent future developers from producing North Slope oil.

There are many aspects of the settlement that contribute to higher tariffs in later years. One of APUC's biggest criticisms of the settlement is that the 35 cent barrel return is not cost-based and may lead to excessive rates of return and tariffs after 1989. APUC also criticized the settlement for eliminating all refund obligations prior to 1982. This means a potential loss of billions of dollars to early year shippers as well as the state of Alaska and the federal government.

A recent decision by FERC on pipeline ratemaking dubbed "Williams II" has been the subject of much speculation. The decision was handed down the same day last June that the state submitted its settlement proposal. The decision appeared to be more favorable to the state's litigation position, though a Department of Revenue analysis of the settlement shows that the settlement may actually be better than a "Williams II" outcome. In any case, it is difficult to say exactly how or if this case would apply to Alaska. In response to a letter written by some House Majority members opposing the settlement late last year, FERC said the case was not applicable to TAPS.

Settling the dispute relies on how to compute the tariff, which is made up of operating expenses, depreciation, income taxes and after-tax return. Of these four, operating expenses is the least controversial, depreciation and after-tax return the most controversial. The Williams II decision adopted a hybrid ratemaking methodology involving part depreciated original cost and part trended original cost. A depreciated original cost scenario, as set out in the state's litigation position, is much better for the state than the trended for inflation rate base used in the settlement. The inflated base is somewhat of a compromise between the valuation methodology originally sought by TAPS owners and the state's position.

The six TAPS owners who have signed the settlement are: Arco, BP, Exxon, Mobile, Union and Phillips. They collectively own 65% of the pipeline. The other two owners are Amerada Hess and Sohio; Sohio has submitted its own settlement offer to FERC (which Love said would be "disastrous" to the state were it to be approved).

Comments opposing the settlement were filed by Arctic Slope Regional Corporation, Amerada Hess Pipeline Corp., Sohio Pipeline Co. and Sohio Petroleum Co., Tosco Corp., Alaska Oil Co. and AKPIRG.

E. Conclusion

These cases illustrate how various aspects of the production and marketing process provide profit making opportunities for the industry and revenue opportunities for the state. They show the complexity of valuing our oil and how important that value is to maintaining the financial wellbeing of both parties.

PREPAYMENT OF ASSESSED TAXES

THE SOHIO ALASKA PETROLEUM COMPANY JOINS THE DEPARTMENT OF REVENUE IN OPPOSING LEGISLATION THAT WOULD REQUIRE THE PREPAYMENT OF ASSESSED TAXES PRIOR TO FINAL DETERMINATION OF THE CORRECT TAX.

FIRST AND FOREMOST IT MUST BE UNDERSTOOD THAT THE AMOUNTS INITIALLY ASSESSED IN THE AUDIT PROCESS ARE NOT TAXES DUE AND OWING. THE DEPARTMENT OF REVENUE CHALLENGES VALUATIONS AND ACCOUNTING PROCEDURES AND, USING EVERY ASSUMPTION AND INTERPRETATION FAVORABLE TO THE STATE, MAKES AN INITIAL ASSESSMENT. IT IS THE BEGINNING, NOT THE END, OF THE TAX AUDIT PROCEDURE. IT IS THE CEILING - THE MAXIMUM LIABILITY - NOT THE BOTTOM LINE. TO REQUIRE PAYMENT AT THIS STAGE OR AT ANY STAGE PRIOR TO FINAL DETERMINATION, WOULD HAVE ABSOLUTELY NO BENEFICIAL EFFECT:

1. ALASKA HAS HAD NO DIFFICULTY COLLECTING TAXES FROM THE OIL INDUSTRY ONCE THE AMOUNT OF TAX HAS BEEN FINALLY DETERMINED. PREPAYMENT WOULD ONLY BE NECESSARY TO ENSURE THE COLLECTION OF REVENUES. HOWEVER, THE OIL INDUSTRY HAS ENORMOUS FIXED ASSETS IN ALASKA THAT CAN BE MADE SUBJECT TO LIENS SHOULD THAT PROVE NECESSARY.

Therefore imposing a prepayment provision will not improve the State's proven ability to collect taxes, once they are due and owing.

2. Prepayment would not accelerate the audit process and in all likelihood would <u>slow</u> and complicate an already difficult procedure. Taxpayers would insist on the enforcement of their rights to a fair hearing and due process. Lawyers and hearing officers would replace auditors and accountants. Rules of evidence would replace negotiation.

3. The absence of a prepayment provision does not result in taxpayers delaying the audit process to forestall payment. If a taxpayer knows that he will eventually have to pay the tax, it is in his best interest to pay today rather than delaying the procedure. Companies challenge and contest assessments not because they want to delay payment but because they believe the assessed amount is incorrect. Consequently, a prepayment provision would not change the taxpayer's practice of challenging assessments.

4. THE STATE WOULD NOT BENEFIT FROM EARLIER COLLECTION OF THE MONEY. IT WOULD NOT BE IN THE STATE'S BEST INTEREST TO USE PREPAYMENTS FOR THE OPERATING OR CAPITAL BUDGET WHEN, HISTORICALLY, THE INITIAL ASSESSMENTS ARE CHALLENGED AND OFTEN DECREASED. TO ASSURE THAT FUNDS WOULD BE AVAILABLE FOR REFUNDS, PREPAYMENTS WOULD HAVE TO GO INTO A TRUST FUND WHICH WOULD NOT BENEFIT EITHER PARTY.

MOREOVER, THE REQUIREMENT TO PREPAY ASSESSMENTS BEFORE THEY ARE DUE COULD CAUSE IRREPARABLE HARM TO THE TAXPAYER AND THE STATE OF ALASKA. WE BELIEVE THAT PREPAYMENT MAY IN CERTAIN INSTANCES VIOLATE THE TAXPAYER'S RIGHTS TO DUE PROCESS.

THE DUTIES OF THE DEPARTMENT OF REVENUE WILL BE MADE MORE DIFFICULT BY REQUIRING PREPAYMENT OF ASSESSED TAXES. THE AUDIT PROCEDURE WILL BECOME FAR MORE FORMAL AND ADVERSARIAL AT A MUCH EARLIER STAGE. BOOKS AND RECORDS THAT ARE NOW ROUTINELY SUBMITTED TO THE STATE IN ORDER TO SETTLE MINOR VALUATION OR ACCOUNTING PROBLEMS WILL PROBABLY BE PRODUCED ONLY AS A RESULT OF LENGTHY DISCOVERY MOTIONS. AUDITS WILL NOT BE ACCELERATED BUT DELAYED AND EVEN WITH PREPAYMENT INTO A TRUST, THE STATE WILL HAVE A LONGER WAIT BEFORE IT HAS ACCESS TO THE FUNDS.

THE SOHIO ALASKA PETROLEUM COMPANY HAS ALWAYS DEALT IN GOOD FAITH WITH THE DEPARTMENT OF REVENUE. THE AUDIT PROCESS IS

CUMBERSOME AND LENGTHY AND CAN BE IMPROVED. WE ARE WILLING TO WORK WITH THE DEPARTMENT, AND THE LEGISLATURE ON CHANGES THAT COULD BENEFIT ALL PARTIES. THE LENGTH OF THE AUDIT IS DETERMINED, FOR THE MOST PART, BY THE DIFFICULTY OF THE ISSUES, THE AMOUNT OF MONEY INVOLVED, AND THE EXPERIENCE OF TECHNICIANS DOING THE WORK. THE PREPAYMENT OF ASSESSED TAXES WILL NOT CHANGE THESE PARAMETERS AND SPEED REDUCTION OF THE OUTSTANDING ASSESSMENTS.

STATE OF ALASKA

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF REVENUE

POUCH S
JUNEAU, ALASKA 99811
PHONE: (907) 465-2300

OFFICE OF THE COMMISSIONER

January 2, 1986

Back up in yellow paper

RECEIVED
JAN -3 1986
LEGISLATIVE AUDIT

Gerald L. Wilkerson
Division of Legislative Audit
Pouch W
Juneau, AK 99811

Dear Mr. Wilkerson:

We appreciate the opportunity to provide information to you concerning our audit program. Your memorandum of December 3 posed five questions, each asking for statistical information. Our audit staff has compiled this data and are confident that it represents a conservative estimate.

Question #1 How many oil and gas tax years per taxpayer does the Department of Revenue currently have under audit?

Answer:

Chapter 21

	# of taxpayers under audit	Tax year(s) under audit
	4	1981
	3	1980-1981
	3	1979-1981
Total	10	19

Chapter 55

	# of taxpayers under audit	Tax year(s) under audit
	1	1982
	3	1981-1982
	3	1980-1981
	3	1982-1983
	4	1981-1983
	2	1980-1982
Total	16	37

Question #2 Based on historical experience, how much uncollected tax revenue do these backlogged tax audits represent?

Answer:

Potential Deficiency *$463,351,000

* Note: This figure represents potential tax assessments in addition to the $840 million currently in appeal status.

Comment: Presently we have seven auditors assigned to the Chapter 21 and 55 taxes. Often, the field work will require the presence of two or more auditors in order to complete it within a reasonable period of time. Thus, our most experienced auditors may be the lead auditor on one case and be required to assist others on another case. We estimate that with the addition of several more auditors, our most experienced auditors would be able to devote themselves entirely to the larger cases, and not be required to assist in the less productive capacity as an assistant.

Question #3 How many of the tax years referred to in question #1 face "statute of limitations" deadlines within the next twelve months that foreseeably could restrict the State's authority to eventually collect unpaid taxes as determined by an audit?

Answer: There is no restriction on the state's ability to asses taxes in accordance with law. All tax years scheduled in the answer to question #1 will expire on or before December 31, 1986. We expect that each taxpayer will routinely continue to extend the expiration date by signing waivers. While signing waivers effectively gives us additional time in which to complete our audits, in actuality this approach only temporarily postpones work that must be done and increases the backlog of audit cases to be scheduled and completed. See also our answer to Question #5.

Question #4 How many auditors would be needed to alleviate this backlog, plus maintain an adequate ongoing audit effort over the next three fiscal years?

Answer: It should be noted that audits are usually commenced a year or more following the year for which a return is filed. The complexity and number of issues involved in the audits has increased over time and is only now generally understood. As a consequence, our analysis of workload and personnel requirements is undergoing review.

In order to complete the audits of tax years 1979-1983, within the three year period, to begin conducting net profit share lease and royalty audits, and to devote audit resources to smaller producing companies we would need eleven additional auditors. Of the eleven, one position would be hired at the revenue auditor V level as a lead auditor, five would be hired as senior auditors at the revenue auditor IV level and five at the revenue auditor III journeyman level. Adding untrained staff will not immediately alleviate our understaffing problems. At least one year of intensive classroom and on-the-job training is required to bring each recruit to the point where they can perform field audits without close supervision from a lead auditor. Although we would attempt to hire candidates with experience in oil and gas accounting and auditing, the training period involved remains lengthy. As a general rule, an auditor cannot ascend to the lead position without three years experience.

* Note: We have not commented on associated costs which would necessarily be incurred with the hiring of additional auditors. These costs include space lease and computer and data processing expenses, clerical support, office equipment and travel expenses.

Question #5 Based on historical experience, how much increased State revenue would you estimate each additional auditor would produce, over and above each position's associated costs?

Answer: Your question asks "how much increased State revenue" would be generated by adding audit staff. Many variables make this difficult to answer with certainty. The estimate given in question #2 of $463 million is based upon our experience in auditing prior years' oil and gas returns. The issues developed in audits currently under appeal are anticipated to exist on subsequent returns filed. As most of the audit issues are being appealed by the taxpayers, future court decisions may also have a substantial impact on the amount of increased revenue actually received by the State. The $463 million is an estimate of the potential deficiency our auditors may assess. This amount also represents assessments which presumably would be assessed whether or not the audit staff was increased. Additional staff would probably speed assessments and ultimate collections. peal, and eventual collection may be postponed several years.

We must also point out that this non-assessed revenue is not in jeopardy at this time. As stated in the answer to question #3, taxpayers willingly sign statute extension waivers. Should they discontinue this practice, the department would have other alternatives available to it, including jeopardy assessments.

There would be two advantages to increasing the number of auditors on our staff. First, a more comprehensive audit could be conducted and issues which we are currently "passing on" can be further developed, possibly resulting in larger assessments.

Second, by freeing our lead auditors to devote themselves entirely to their own cases, field audits could be completed and assessments issued quicker.

As you are undoubtedly aware, there has been increasing pressure on State government to reduce spending in response to falling revenues. Although it is often times difficult to measure the revenue impact our audit and compliance programs have, we are confident that this agency's audit presence has a significant bearing on revenues ultimately received into the general fund. Using the statistics we compile to measure our performance, for every dollar we spend administering the petroleum related tax types we return $89.58 in additional tax assessments.

Recently we asked several states how much their tax administration programs cost in comparison to total revenues administered. We found that on the low end Washington spends $3.97 per thousand dollars of total receipts. On the high end Montana spends $7.22 and Kansas $8.50 per thousand. At the present time Alaska spends approximately $2.50 for every one thousand dollars in actual tax receipts. Certainly our tax structure differs substantially from those states which impose individual income tax and sales taxes. We do not require the one hundred or more auditors which these states employ.

Sincerely,

for

Bruce M. Botelho
Deputy Commissioner
for Taxation

BMB:SEK:mll

cc: Ray Gillespie
Chief of Staff
Office of the Governor

BILL SHEFFIELD, GOVERNOR

REPLY TO:

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DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

January 29, 1986

Honorable Al Adams
Alaska State Legislature
Pouch V
State Capital
Juneau, Alaska 99811

Re: Prepayment of disputed taxes
Our file: 166-268-86

Dear Representative Adams:

You have requested our opinion on the constitutionality of requiring payment of disputed taxes from taxpayers pending proper appeal of the assessed amounts. You have also asked our opinion on when in the dispute resolution process such payment would be appropriate and whether the collected sums must be put in escrow pending the outcome of the dispute. You have noted that you are especially interested in these questions as they concern taxes owed to the state by the oil and gas corporations under AS 43.21, AS 43.20 and AS 43.55, since, you have stated,"back taxes under these three statutes currently total about $900 million." Thus, you are interested in whether any proposed changes in the appeal process to require payment of disputed taxes may be applied to the cases currently pending.

We conclude that a requirement that disputed taxes be paid at some point prior to final resolution of the dispute in the courts is permissible under both the Alaska and United States constitutions. We also believe that a statute requiring that taxes be paid pending appeal could be drafted so as to apply to disputes pending at the administrative level at the time of enactment and further, that the state need not escrow payments of disputed taxes but could enact valid legislation authorizing such procedures.

Finally, although we have found nothing that would bar legislation creating a prepayment requirement, we think that there are some practical and policy concerns that would have to be addressed in connection with any specific proposal to change the procedures for the collection of disputed taxes. The Department of Revenue has a number of comments as to the practical implications of any proposed legislation in this area and will be providing you with a list of their concerns.

03-C5LH

BACKGROUND: EXISTING PROCEDURES AND APPLICABLE STATUTES AND REGULATIONS

The procedures for taxpayer appeals are currently governed by AS 43.05.240 and Alaska Appellate Rules 602(c) and 204. AS 43.05.240 controls the administrative appeal process and generally provides for a two step process. 1/ In most instances the

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1/ AS 43.05.240 provides as follows:

Taxpayer remedies. (a) A person aggrieved by the action of the department in fixing the amount of a tax or in imposing a penalty may apply to the department within 60 days from the date of mailing the notice [of assessment] ... giving notice of the grievance and requesting an informal conference. At the conference the person aggrieved may present arguments and evidence relevant to the amount of tax or penalty due the state. If the department determines that a correction is warranted, the department shall make the correction.

(b) A person aggrieved by the action of the department in fixing the amount of a tax or in imposing a penalty may apply to the department and request a formal hearing

(1) in place of the informal conference provided for in (a) of this section ...or;

(2) within 30 days after decision resulting from an informal conference.

(c) At the formal hearing the department may subpoena witnesses and may administer oaths and make inquiries necessary to determine the amount of the tax or penalty due the state. The person aggrieved may present arguments and evidence relevant to the amount of the tax penalty due the state. If the department determines that a correction is warranted, the department shall make the correction.

(d) Within 30 days after the formal hearing and decision by the department, a person aggrieved by the decision of the department may appeal to the superior court in the judicial district in which the person resides. If after the appeal is heard it appears that the tax was correct, the court shall confirm the tax. If incorrect, the court shall determine the amount of the tax and if the person aggrieved is entitled to recover the tax or part of it,

(footnote continued)

taxpayer who wishes to protest an assessment begins by requesting an informal conference. 2/ The purpose of the informal conference is both to resolve the dispute, if possible, and to clarify those issues left to be resolved at the formal hearing. In fact, many disputes are resolved at this level.

A taxpayer who does not agree with the informal conference decision may then request a formal hearing. However, the taxpayer first pays any part of the assessment that relates to issues resolved at the informal conference level, thus, streamlining the matters to be addressed at the formal hearing.

The formal hearing is conducted by a hearing officer and is governed by trial-type procedures under which the taxpayer and audit staff may call witnesses to testify under oath, cross-examine witnesses, and introduce documentary evidence relevant to determining the amount of tax due. 3/ AS 43.05.240; 15 AAC 05.030.

If, after the formal hearing decision, any part of the assessment is still in dispute, appeal is to the superior court. AS 43.05.240(d) provides that a taxpayer may appeal to superior court within 30 days after the formal hearing decision is issued. This statute does not expressly require the taxpayer to pay the disputed taxes before appealing to asuperior court. However, Section 240(d) can reasonably be interpreted to require prepayment prior to judicial review and this interpretation is reflected in the department's regulations. 15 AAC 05.040 requires full payment of

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(footnote continued)

> the court shall order the repayment and the department shall immediately pay the amount due....

2/ Although the informal conference can be waived, <u>see</u> AS 43.05.240 (b)(1), the department discourages this practice since it often leads to delays in the formal hearing process as numerous pre-conference hearings become necessary to clarify issues and generally accomplish those matters usually accomplished by the informal conference.

3/ According to representatives of the Department of Revenue, at formal hearing taxpayers win at least a partial abatement in approximately 50% of the appeals of assessments under all tax laws.

the amount determined to be due by the final administrative decision of the department pending appeal to the court.

When an appeal is filed in court, the Appellate Rules of the Alaska Courts come into play. Appellate Rules 602(c) and 204(d) grant the appealing taxpayer the right to stay the administrative decision by filing an approved supersedeas bond for the amount of a potential judgment. 4/ Any legislation aimed at removing the superior court's power to approve the filing of a supersedeas bond in lieu of payment of the disputed taxes would have to provide for amending these Appellate Rules. This can be done, but only by a two-thirds vote of the members of each house. Alaska Const. Art. IV, sec. 15.

You should also be aware that a number of other statutory provisions would be affected by a prepayment requirement. An example is AS 43.20.270 which provides that the department may collect taxes by distraint and sale from a taxpayer who has not appealed from the assessment.

I. CONSTITUTIONALITY OF REQUIRING PAYMENT OF DISPUTED TAXES PRIOR TO FINAL DETERMINATION OF TAX LIABILITY

The obligation to pay taxes is purely a statutory creation. The methods by which the state may assess and collect a tax, as well as taxpayer remedies, are controlled by the express wording of the taxing statutes . The state legislature has discretion to set the conditions precedent to any refund, limited only by constitutional considerations of due process. See generally 71 Am. Jur. 2d, State and Local Taxation, secs. 596,608 (1973).

The due process clause of the Alaska Constitution is set out in Article I, Section 7 and provides: "No person shall be deprived of life, liberty, or property, without due process of law..." The core of this guarantee is the right to notice and a hearing when

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4/ This may be why the Department of Revenue has not generally enforced its regulation requiring payment of disputed taxes pending appeal. We know of one case in which the Department asked the superior court to require full payment of taxes in lieu of a supersedeas bond but the court approved a bond in accordance with the Appellate Rules.

state action threatens the deprivation of some material right. Matanuska Maid, Inc. v. State, 620 P.2d 182 (1980). The language of the parallel federal due process guarantee, contained and the fifth and fourteenth amendments, is identical to that contained in the Alaska Constitution.

Under the applicable federal tax procedures, a taxpayer is given the choice of appealing through administrative procedures to Tax Court or going directly to federal district court. A taxpayer may appeal to Tax Court without paying disputed taxes and on to the Court of Appeals upon paying a bond. However, full payment of all disputed taxes is a prerequisite to going directly to federal district court, since jurisdiction over tax matters in the district courts exists only for actions "for the recovery of taxes alleged to have been erroneously or illegally assessed or collected," 28 U.S.C. sec. 1346. The requirement that a taxpayer pay the disputed taxes in full as a precondition of judicial review has been challenged on due process grounds and upheld by the federal courts. Johnston v. Comm'r of Int. Rev., 429 F.2d 804 (6th Cir. 1970) (due process not violated where taxpayer was barred from administrative appeal and had to pay full disputed tax amount to challenge tax in federal court); see, Flora v. United States, 357 U.S. 63 (1958).

Thus, while a taxpayer who disputes an assessment is guaranteed some right to a notice and hearing on the disputed amount, it is unlikely that the hearing must occur prior to any attempt at collection of the taxes assessed by the taxing authority. Both federal courts and courts in other states have held that due process is satisfied by the provision for a hearing after payment of taxes on the taxpayer's liability for taxes it alleges are wrongfully collected. See e.g., Phillips v. Comm'r of Int. Rev., 283 U.S. 589 (1931); Johnston v. Commissioner of Internal Revenue, 429 F.2d 804 (6th Cir. 1970); Cohen v. U.S., 297 F.2d 760 (9th Cir. 1962); State Tax Commission v. Yavapai County, 29 P. 2d 733 (Ariz. 1934); Anderson Bros. Corp. v. Stone, 85 So. 2d 767 (Miss. 1956); see generally 72 Am Jur 2d, State and Local Taxation, sec. 786 (1973).

The Alaska Courts have not addressed the issue of prepayment of taxes. While the Alaska courts certainly look to federal precedent, they are not limited to these rulings, since the provisions of the state constitution may have broader safeguards than the federal standards. Shagloak v. State, 597 P.2d 142 (Alaska 1979). However, based on the federal precedent and other caselaw cited above, we believe that the Alaska Supreme Court would uphold, against due process challenge, a statutory requirement that taxes be paid at some point in the appeal process as a prerequisite to further review. 5/

You have asked, however, at what point in the process we believe prepayment would be "appropriate". As a matter of policy the choice of when to require full payment is of course up to the legislature. However, as a legal matter, we believe that the likelihood of any successful challenge to a prepayment requirement would decrease in direct proportion to the number of procedural safeguards available for use by the taxpayer prior to required payment. Thus, we believe that imposition of the requirement at the conclusion of the formal hearing is the least vulnerable point. However, we have found nothing to suggest that payment could not be required after the informal conference or possibly even earlier as long as there remains notice and an opportunity for a hearing to challenge the tax at some reasonable stage of the proceedings.

II. APPLICATION OF THE PREPAYMENT REQUIREMENT TO CURRENTLY PENDING CASES

It is our opinion that a change in the taxing procedures to require a prepayment of disputed tax liabilities could legally be applied to appeals that are currently pending at the administrative level. A taxpayer might attempt to challenge the application of any prepayment requirement to existing cases on the grounds that such an application would be unconstitutionally retroactive. However, we do not believe such a challenge would succeed.

5/ We think, however, that a small taxpayer appealing corporate income tax assessments under 43.20 might challenge a prepayment requirement on due process or other grounds. An argument that a specific taxpayer cannot afford to pay the full, assessed amount before appeal and would therefore be irreparably harmed by strict application of the prepayment requirement might be receptively received by a court. In such a case, the court could decide to stay the application of the prepayment statute or reduce the amount required to be paid on due process grounds or as an exercise of its general equitable powers. It would be unlikely, however, to hold the statute unconstitutional on its face.

A retroactive 6/ statute is "one which gives to pre-enactment conduct a different legal effect from that which it would have had without the passage of the statute," Norton v. Alcoholic Beverage Control Board, 695 P. 2d 1090, 1093 (Alaska 1985) citing Hochman, The Supreme Court and the Constitutionality of Retroactive Legislation, 73 Harv. L. Rev. 692 (1960). While this definition might lead to arguments over whether applying a statutory change to require prepayment of disputed taxes to pending cases is a retroactive application, the argument would be largely irrelevant. Procedural changes that do not effect substantive rights may be retroactively applied. Matanuska Maid, Inc. v. State, 620 P.2d 182, 187 (Alaska 1980). The theory behind the constitutional prohibition against retroactivity is that a statute should not operate to deprive a person of vested rights. However, for over a century, the rule has been that no party has a vested right in any statutory remedy. See The Collector (Brainard) v. Hubbard, 79 U.S. 1 (1871) cited in Bidwell V. Scheele, 355 P.2d 584, 586 (Alaska 1960).

Thus, in the Bidwell case, the Alaska Supreme Court held that the repeal of a statute requiring a person bringing a claim of title to lands against the holder of tax title to pay the equivalent of the sale price of the lands into the court should be applied to a pending action. The purchaser had no right in the previous procedure. Similarly, a taxpayer has no right to the present tax appeal procedures that permit a full appeal prior to any requirement to pay disputed liabilities.

The intent to apply a change in the tax appeal procedures to pending cases, however, would have to be stated expressly in the statute. AS 01.10.090 provides: "No statute is retrospective unless expressly declared therein." The statute need not use the specific word, "retrospective" but the legislature must clearly express its intent. See also, AS 01.10.100 (repeal or amendment of a law does not extinguish existing rights unless act expressly so states).

III. ESCROW OF DISPUTED TAX LIABILITIES

While your opinion request asks only whether payments received under a prepayment scheme must be escrowed, further conversations suggest you are also interested in the legislature's

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6/ Legislation may be referred to as either retroactive or retrospective; for our purposes the terms are synonymous.

authority to set up some sort of procedure for holding the prepaid amounts for future refund pending resolution of tax disputes. Thus, we perceive your question to be whether or not the decision to escrow these sums may legally be left to the legislature.

As to the first part of your question, we have found nothing that would require the state to escrow disputed tax liabilities. The federal government, for example, does not escrow the amounts it collects pending district court tax proceedings. 7/ Moreover, the contrary view, if applied to all tax disputes, might seriously impair a government's ability to function.

It is more difficult to respond to your inquiry concerning the validity of a mechanism for holding funds for possible repayment in the event the state does not prevail on its tax claims. There are many different methods that could be proposed for holding the disputed funds, and, while we believe that the legislature has broad discretion to chose among these methods, we think that there could be problems associated with some of them. See, e.g., 1982 Op. Att'y Gen. No. 13 (Nov. 30) (discussing dedicated funds prohibition as it applies to various types of funding mechanisms). In short, we think that a valid procedure for holding disputed funds for possible refund could be devised, however, we cannot give any more specific advice without more information.

We hope that this answers your immediate questions. We will be happy to assist you in any further questions you might have.

Sincerely yours,

HAROLD M. BROWN
ATTORNEY GENERAL

By: Karen L. Loeffler
Karen L. Loeffler
Assistant Attorney General

KLL/ma

7/ As a practical matter, however, Alaska's situation does not resemble that of the federal government. While the latter operates from a deficit, we do not. Thus, the need to reserve disputed funds could differ.

ALASKA DEPARTMENT OF REVENUE

TAX ACCOUNTS RECEIVABLE SUMMARY

January 27, 1986

TAX TYPE	STATUTE	VALUE OF ACCOUNTS (A)	NOTICES OF ASSESSMENT	APPEALED	DELINQUENT AND ASSIGNED	CURRENTLY NOT COLLECTABLE
OIL & GAS CORP INC	AS 43.21	$526,772,908.17	$ .00	$512,075,822.99	$14,697,085.18	$ .00
OIL & GAS PRODUCTION	AS 43.55	324,527,153.90	.00	305,381,467.08	19,145,686.82	.00
CORPORATE INCOME	AS 43.20	69,176,297.80	5,397,996.48	62,532,919.02	1,094,023.02	151,359.28
INDIVIDUAL INCOME	AS 43.20	11,347,827.74	270,248.46	2,669,881.90	8,036,651.75	371,045.63
FISHERIES	AS 43.75	8,757,028.01	48,060.42	1,415,850.94	6,829,572.39	463,544.26
MOTOR FUEL	AS 43.40	3,860,528.83	137,954.22	1,535,943.79	2,185,737.86	892.96
BUSINESS LIC GR RCPT	AS 43.70	3,156,662.83	.00	2,664,285.70	364,685.32	127,691.81
INDIVIDUAL WITHHOLD	AS 43.20	2,210,965.67	156.44	7,614.84	1,899,890.53	303,303.86
MINING	AS 43.65	1,811,998.67	979,553.57	832,445.10	.00	.00
OIL & GAS PROPERTY	AS 43.56	1,186,349.32	57,559.39	386,930.57	741,859.36	.00
SALMON ENHANCEMENT	AS 43.76	496,708.54	68,793.22	43,687.78	384,027.54	.00
FIDICUARY INCOME	AS 43.20	203,100.18	.00	184,228.30	18,871.88	.00
SEAFOOD MARKETING	AS 16.51	148,537.66	2,469.83	8,146.73	133,784.40	4,136.70
LIQUOR EXCISE	AS 43.60	54,912.90	.00	487.87	54,425.03	.00
TOBACCO (CIGARETTE)	AS 43.50	22,432.79	.00	4,498.12	17,934.67	.00
ESTATE	AS 43.31	9,793.36	5,827.05	.00	3,966.31	.00
COIN OPERATED DEVICE	AS 43.35	6,200.25	.00	.00	6,064.02	136.23
WHSL CANNED SALMON	AS 43.80	2,250.00	.00	2,250.00	.00	.00
TOTAL TAX RECEIVABLES (A)		$953,751,656.62	$6,968,619.08	$889,746,660.73	$55,614,266.08	$1,422,110.73
PERCENT OF TOTAL VALUE		100.00%	0.73%	93.29%	5.83%	0.15%
PERCENT OF WORKABLE VALUE					97.51%	2.49%

TAX TYPE	STATUTE	NUMBER OF ACCOUNTS (B)	NOTICES OF ASSESSMENT	APPEALED	DELINQUENT AND ASSIGNED	CURRENTLY NOT COLLECTABLE
INDIVIDUAL INCOME	AS 43.20	1,554	35	267	1,024	228
CORPORATE INCOME	AS 43.20	861	196	425	206	34
INDIVIDUAL WITHHOLD	AS 43.20	673	4	5	450	214
OIL & GAS PRODUCTION	AS 43.55	499	0	482	17	0
MOTOR FUEL	AS 43.40	411	46	151	209	5
FISHERIES	AS 43.75	269	9	54	166	40
BUSINESS LIC GR RCPT	AS 43.70	198	0	48	91	59
SALMON ENHANCEMENT	AS 43.76	97	8	21	68	0
SEAFOOD MARKETING	AS 16.51	60	5	7	46	2
OIL & GAS CORP INC	AS 43.21	36	0	34	2	0
OIL & GAS PROPERTY	AS 43.56	34	6	5	23	0
ESTATE	AS 43.31	15	8	1	6	0
LIQUOR EXCISE	AS 43.60	15	2	1	12	0
COIN OPERATED DEVICE	AS 43.35	13	0	0	11	2
MINING	AS 43.65	10	2	8	0	0
FIDICUARY INCOME	AS 43.20	9	0	7	2	0
TOBACCO (CIGARETTE)	AS 43.50	7	1	3	3	0
WHSL CANNED SALMON	AS 43.80	3	0	3	0	0
TOTAL TAX ACCOUNTS (B)		4,764	322	1,522	2,336	584
PERCENT OF TOTAL ACCOUNTS		100.00%	6.76%	31.95%	49.03%	12.26%
PERCENT OF WORKABLE ACCOUNTS					80.00%	20.00%

ALASKA DEPARTMENT OF REVENUE
TAX ACCOUNTS RECEIVABLE SUMMARY
January 27, 1986

NOTES:

A. The value of receivables reported, especially those in appeal status, are still subject to some review and correction.

At the end of October, 1985, the Enforcement Division completed the consolidation of all receivables on to a new computer based accounts receivable system, giving the Department the ability to generate summary statistics of tax receivables. Upon review of these statistics, certain anomalies have been identified, some of which have resulted in correction of reported receivables. In a few instances keypunch errors have been identified. In a few other cases unposted payments have been identified, most notably involving those assessments under appeal.

The Enforcement and Audit Divisions are working to reconcile what the accounts receivable system shows in appeal status with what Audit's conference staff shows in appeal status. As that reconciliation is conducted the number of accounts and the aggregate value of those accounts may change.

In addition, several accounts related to a settlement announced January 13, 1986 have not yet been posted although payment was received January 15, 1986.

B. The number of accounts identifies the number of actual billings, not the number of taxpayers. A single taxpayer may have billings for several different tax periods and/or for several different tax types. Accordingly, the actual number of taxpayer appeal cases will be less than the number of accounts identified on this summary.

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF REVENUE

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OFFICE OF THE COMMISSIONER

January 30, 1986

The Honorable Al Adams
Chairman
House Finance Subcommittee on Oil and Gas
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Re: Expedite Collection of Disputed Taxes

Dear Representative Adams:

A proposal has been raised in the Interim Report of the House Finance Subcommittee on Oil and Gas (January 17, 1986) to require prepayment of disputed taxes at some stage in the appeal process in order to expedite the collection of disputed taxes. We appreciate the opportunity afforded us to comment on this issue.

The Department of Revenue is concerned that the proposal will have a detrimental impact on its operations, emphasis, and ability to litigate tax challenges. Rather than expedite resolution of tax disputes, it is the Department's view that the prepayment requirement concerning disputed taxes will create delays. The adverse impact will be greater the earlier the prepayment requirement is imposed. Additionally, the prepayment proposal will affect taxpayers other than oil and gas companies if it is imposed on the corporation net income tax under AS 43.20 et. seq.

Instead, we believe the collection of disputed taxes can be expedited more successfully through approaches other than the prepayment requirement. These approaches have been recently adopted and their effect is already being felt.

In this letter, we outline the handling of disputed tax controversies by examining the assessment and appeal process, discussing the reasons for delays, and the effect the prepayment requirement may have on the various levels of the Department's appeal process.

I. The Assessment And Appeal Process

There are two levels of administrative appeal within the Department, the informal conference and the formal hearing. Appeal after the formal hearing decision is to Alaska Superior Court. The appeal process can proceed through the courts to the U.S. Supreme Court. Final resolution of the appeal occurs after exhaustion or waiver of judicial appeal rights. It is only then that the disputed taxes must be paid if the final determination is against the taxpayer.

A. The Assessment Level Of Review

The Audit Division is responsible for reviewing tax returns and monitoring taxpayers through audits to insure that taxable income is properly calculated and reported. If the Division determines that an adjustment is required, it will inform the taxpayer that either more taxes are owed or a refund is warranted. If more taxes are due, an assessment notice will be issued.

As a practical matter, assessments are often made as the three year statute of limitations is about to expire. These assessments are often high as compared to the final adjusted assessment made during the appeal period. The reason is that auditors must make an aggressive although reasonable evaluation in order to insure that the State receives the money it is entitled to. They cannot later amend the assessment after the statute of limitations for assessments has expired except under limited circumstances. The taxpayer has the right to appeal an assessment within 60 days of being notified of an assessment.

1. Reasons For Delay

There are two primary reasons for delay during the assessment period. Assessments often are made as the three year statute of limitations is about to expire because audits of taxpayers, especially large multi-state and multi-national taxpayers, can take years to complete. Other audits underway may deal with the same issue or taxpayer. It is not an administratively sound practice to litigate the same issue for each taxpayer for each tax year. Accordingly, a delay may occur to allow a "lead" audit to proceed to completion.

2. Prepayment after Assessment

As a practical matter, if prepayment were required after the assessment, taxpayers might not be as cooperative in providing the information during the three year audit period, or in waiving the statute of limitations. This lack of cooperation would require the department to employ more discovery devices (subpoenas, summons, interrogatories, depositions, etc.), which would be costly in both time and money.

B. Informal Conference

The informal conference is the first level of review of a challenged assessment. A conference officer discusses the assessment with the taxpayer through correspondence, in-person, or through telephone conferences. Unlike the formal hearing in which the Appeals Section does take an adversary role on behalf of the Audit Division, the purposee of the informal conference is to provide an opportunity for discussion. As a result of this nonadversarial approach, the expertise of the Appeals Section, and its ability to settle cases, nearly 90% of all assessment disputes are resolved at the informal conference level of review.

1. Reasons For Delay

There are a number of reasons for delay at the informal conference level. Many of these reasons are identical to those experienced at the assessment level. The time frame for holding an informal conference may vary, depending on the complexity of the issues, stays and consolidations of appeal, the availability of the pertinent officials of the taxpayer, the number of informal conference officers, etc.. A great deal of the assessment actions have been stayed until resolution of certain basic issues. Staying appeal cases allows the Department to screen similar cases and proceed with the "best" test case.

2. Prepayment after Informal Conference

If prepayment of disputed taxes is required after the informal conference decision, the nature of the informal conference will become adversarial. Part of the reason for this change in atmosphere is that attorneys will be forced to enter the tax appeal process at an earlier stage of review.

C. Formal Hearing

The formal hearing is the administrative trial level for tax disputes. A Department of Revenue hearing examiner is appointed by the Commissioner to serve as a hearing officer for the appeal. A formal hearing is often preceded by a prehearing conference, briefing, and discovery requests. Full due process safeguards are provided with adequate notice and full opportunity to be heard by an impartial hearing officer. A formal hearing decision is issued after the record is closed and reviewed.

1. Delays In The Formal Hearing Process

Delays have occurred in the formal hearing process for some of the same reasons previously mentioned. In addition, the nature of the hearing process in affording both the taxpayer and the Audit Division the full opportunity to explain their respective cases causes delays. Additionally, since the Hearing Examiner Section handles not only tax appeals but other revenue appeals, staff limitations and backlogs of cases contribute to delays. Delays have also resulted because of stays pending resolution of a number of tax cases before the courts, both at the federal and state levels.

2. Prepayment of Disputed Taxes After Formal Hearing

Payment after formal hearing occurs, of course, if the taxpayer does not appeal to the Superior Court. Prepayment as a condition or prerequisite for judicial action may require the creation of a different form of action. In other words, instead of an appeal, a taxpayer would file an original action claiming a refund. The Superior Court would not be limited to review of the formal administrative record, but would, in effect, try the case de novo. The Department's concerns about such a procedure are two-fold: one, delays of substantial periods would be encountered; and, two, the Court's decisions on tax issues would not be based upon the administrative record, but upon new findings of fact and conclusions of law. In effect, contested cases will have two trials with potentially differing results, creating confusion in the interpretation of Alaska's tax law.

D. Other State's Assessment And Appeal Processes

We are unaware of any state that requires prepayment of disputed income taxes during the administrative appeal process, although some require payment at later levels of judicial review. State Tax Review Agencies: Organization and Practices, Federation of Tax Administrators Research Report No. 79 (December 1978). The prepayment requirement for disputed taxes is often limited to certain types of taxes that would therefore effect a limited group of taxpayers. See In the Matter of the Tax Appeal of Simpson Mannor, Inc., 548 P.2d 246 (Haw. 1976) (excise taxpayers required to pay before proceeding to Tax Appeals Court, although net income, real property, public service company and bank franchise taxpayers could appeal without prepayment of disputed taxes).

II. Alternative means to Expedite Collections Of Disputed Taxes

There are a number of alternatives to prepayment of disputed taxes, many of which we have implemented to expedite the collection process for appealed taxes.

At the audit level, assessments are progressing at a more rapid rate. The major reason for this change is that through experience, advanced marketing data, familiarity with the various taxpayers' businesses, and clarification of legal issues and positions, audits are shorter in duration and more thorough. Also, resolution of certain issues has resulted in fewer contested issues.

At the informal conference level, a major breakthrough in the dam of backlogged cases was the judicial resolution of the constitutionality of the separate accounting methodology under AS 43.21 et. seq.. ARCO v. State of Alaska, Department of Revenue, Alaska Supreme Ct. Op. No. 2965 (August 16, 1985, appeal dismissed by the U.S. Supreme Ct on January 13, 1986. Now, other issues that were stayed pending the resolution of the constitutional issues are progressing through informal conferences.

Another major change is the transfer of the informal conference functions to the Appeals Section of the Audit Division. The Appeals Section has five conference staff members who are attorneys, CPAs, or audit staff with extensive years of experience in tax matters.

At the formal hearing level, the Alaska Supreme Court's resolution of various tax issues has greatly impacted the number of cases or issues stayed at the formal hearing level of appeal. The reduction in the backlog of cases and additional staff should enable the Hearing Examiner Section to be able to issue a decision within six months of closure of a hearing by the end of 1986.

Another major change affecting the collection of disputed tax monies was the increase in the tax interest rate. AS 43.05.225 was amended in 1982 by raising the interest rate on delinquent taxes from eight percent to twelve percent. As a result, taxpayers no longer have the disincentive to pay and then to use the disputed taxes on other investment opportunities while the appeal is pending.

III. Summation

We have strong concerns that the requirement to prepay disputed taxes at some level in the review process will not expedite the resolution of disputed tax cases. Rather, we think it could impair the strategy and ability of the Department to defend its assessments and may create an adversary relationship that could permeate the assessment and appeal process, end the practice of voluntary compliance, hamper the ability of the Department to obtain needed information, diminish the Department's success rate in defending its assessments and decisions, delay the resolution process, and require additional staff at every level of the assessment and appeal process.

We believe that expedition of collecting disputed taxes is better accomplished through other approaches, many of which are currently being implemented. Greater experience and knowledge at the audit level in administering the new tax programs, a more proficient appeals staff, negotiated settlements of cases at the informal conference level, reduction of the backlog of appeals at the formal hearing level, and recent Alaska Supreme Court cases have and will greatly expedite the resolution of disputed tax cases. An increase in the interest rate has already spurred early payment of disputed taxes. These changes should insure earlier payment of taxes owed the State.

Sincerely,

Bruce Botelho

Bruce M. Botelho
Deputy Commissioner, Taxation

Theresa Hillhouse

Theresa Hillhouse
Revenue Chief Hearing Examiner

cc: Members of the House Finance Committee

Karen L. Loeffler
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