HOUSE RESEARCH AGENCY

SLIDING SEVERANCE TAX PROPOSAL

Existing Law

$ELF = (1 - PEL/TP)$

ELF = economic limit factor
PEL = production at economic level
TP = total production

Severance Tax = 12.25% X ELF X GP X .875

GP = Gross value of production

Introduce Accrued Value Factor (AVF)

$$AVF = \frac{OPI}{BI}$$

OPI = oil price inflation

$$= 1 + \frac{PP - BP}{BP}$$

PP = present oil price
BP = base oil price

BI = base inflation

$$= 1 + \frac{PCPI - BCPI}{BCPI}$$

PCPI = present consumer price index
BCPI = base consumer price index

AVF = 1 if oil price inflation = base inflation
= 2 if oil price inflation = twice the base inflation rate
= 3 if oil price inflation = 3 times the base inflation rate

$$\text{Scale Factor} = \frac{AVF - 1}{AVF} = SF$$

AVF=	SF=
1.1	.09
1.2	.16
1.5	.33
2.0	.5

Proposed severance tax formula = (SS X SF + .1225) X GV X .875

SS = state share of accrued value of oil fraction between 0 and 1
GV = gross wellhead value of oil

Effect of Proposed Severance Tax
on the Nominal Severance Tax Rate

State's Share	Oil Price Inflation Factor	Base Inflation Factor	Adjusted Nominal Sev. Tax Rate
50%	1.5	1.2	22.3%
50%	2.0	1.2	32.3%
50%	1.5	1.5	12.25%
80%	1.5	1.2	28.3%
80%	2.0	1.2	44.3%
50%	30	1.1	60.4%
50%	1,000,000	1.0	62.25%

THE LEGISLATURE OF THE STATE OF ALASKA
ELEVENTH LEGISLATURE

FISCAL NOTE

I. REQUEST

Bill/Resolution No. SB 474

Title Repealing Chapter 20 & Amending Chapter 21 of Title 43

Requested by Senate State Affairs & Finance Committees Date 2-24-80

II. FISCAL DETAIL

Agency Affected Revenue

Program Category Affected General Government

BRU, Program, or Subprogram(s) Affected Administration & Support, Management Services

(Note: If more than one budget component is affected, separate line-item amounts and funding for each component in the analysis section.)

EXPENDITURES (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
100 PERSONAL SERVICES		(758.5)	(758.5)	(758.5)	(758.5)	(758.5)
200 TRAVEL		(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
300 CONTRACTUAL		(145.0)	(145.0)	(145.0)	(145.0)	(145.0)
400 COMMODITIES		(2.0)	(2.0)	(2.0)	(2.0)	(2.0)
500 EQUIPMENT						
600 LAND & STRUCTURES		(64.0)	(64.0)	(64.0)	(64.0)	(64.0)
700 GRANTS, CLAIMS, ETC.						
TOTAL		(971.1)	(971.1)	(971.1)	(971.1)	(971.1)

FUNDING (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
GENERAL FUND		(971.1)	(971.1)	(971.1)	(971.1)	(971.1)
FEDERAL FUNDS						
OTHER (Specify Fund Source)						

POSITIONS

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
FULL TIME		24/288mm	24/288mm	24/288mm	24/288mm	24/288mm
PART TIME		14/63mm	14/63mm	14/63mm	14/63mm	14/63mm
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

Repeal of AS 43.20 would reduce the number of Administrative Services' positions from 63 to 22. The permanent part-time positions would reduce from 14 to 0 and the three CETA positions would be deleted. Administrative Services would still serve about 195 employees after positions deleted by the repeal have been subtracted from other divisions.

IV. DATE March 3, 1980 PREPARED BY P. A. Wall

P A Wall

AGENCY Revenue

PHONE 465-2313

Original: Legislative Finance

cc: Budget and Management

Prime Sponsor (First Legislator Named)

33-001 (Rev. 12/79)

FISCAL NOTE

I. REQUEST
Bill/Resolution No. SB 474
Title Repealing AS 43.20; Amending AS 43.21
Requested by ______ Date ______

II. FISCAL DETAIL
Agency Affected Revenue
Program Category Affected General Government
BRU, Program, or Subprogram(s) Affected Petroleum Revenue
(Note: If more than one budget component is affected, separate line-item amounts and funding for each component in the analysis section.)

EXPENDITURES (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
100 PERSONAL SERVICES	-0-	-0-	-0-	-0-	-0-	-0-
200 TRAVEL	-0-	-0-	-0-	-0-	-0-	-0-
300 CONTRACTUAL	-0-	-0-	-0-	-0-	-0-	-0-
400 COMMODITIES	-0-	-0-	-0-	-0-	-0-	-0-
500 EQUIPMENT	-0-	-0-	-0-	-0-	-0-	-0-
600 LAND & STRUCTURES	-0-	-0-	-0-	-0-	-0-	-0-
700 GRANTS, CLAIMS, ETC.	-0-	-0-	-0-	-0-	-0-	-0-
TOTAL	-0-	-0-	-0-	-0-	-0-	-0-

FUNDING (Thousands of Dollars)

GENERAL FUND	-0-	-0-	-0-	-0-	-0-	-0-
FEDERAL FUNDS	-0-	-0-	-0-	-0-	-0-	-0-
OTHER (Specify Fund Source)	-0-	-0-	-0-	-0-	-0-	-0-

POSITIONS

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

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

The bill would not impact the operations or budget of the Division of Petroleum Revenue.

IV. DATE 2/29/80 PREPARED BY Robert M. Johnson
AGENCY Department of Revenue
PHONE 276-1363

Original: Legislative Finance
cc: Budget and Management
Prime Sponsor (First Legislator Named)

33-001 (Rev. 12/79)

FISCAL NOTE

I. REQUEST

Bill/Resolution No. SB 474

Title An Act repealing the Individual and Corporation Income Tax; ammending the Oil and

Requested by · Date Gas Corp. Income Tax

II. FISCAL DETAIL

Agency Affected

Program Category Affected

BRU, Program, or Subprogram(s) Affected

(Note: If more than one budget component is affected, separate line-item amounts and funding for each component in the analysis section.)

EXPENDITURES (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
100 PERSONAL SERVICES						
200 TRAVEL						
300 CONTRACTUAL						
400 COMMODITIES						
500 EQUIPMENT						
600 LAND & STRUCTURES						
700 GRANTS, CLAIMS, ETC.						
TOTAL						

FUNDING (MILLIONS of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
GENERAL FUND	-0-	(229.5)	(262.5)	(305.0)	(382.0)	(474.0)
FEDERAL FUNDS						
OTHER (Specify Fund Source)						

POSITIONS

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
FULL TIME						
PART TIME						
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

The bill proposes to repeal the Individual and Corporation Income Tax. It also proposes to amend the Oil and Gas Corporation Income Tax.

The repeal would become effective July 1, 1980 and would apply to income earned after December 31, 1979.

The above estimate reflects the potential revenue impact of the repeal of the Individual and Corporation Income Tax only.

IV. DATE 2/25/80

PREPARED BY Barbara Soren
AGENCY Revenue
PHONE #2174

Original: Legislative Finance
cc: Budget and Management
Prime Sponsor (First Legislator Named)

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER / POUCH S – JUNEAU 99811

March 6, 1980

The Honorable Bob Mulcahy
Chairman
Senate State Affairs Committee
Room 514 - Capitol Building
Juneau, Alaska 99811

Dear Senator Mulcahy:

Re: Senate Bill No. 474

Senate Bill No. 474, an Act Repealing Chapter 20 and amending Chapter 21 of Title 43, Alaska Statutes, was introduced to the Senate on February 18, 1980 and was referred to the Senate State Affairs and Finance Commttees.

For the consideration of the Senate State Affairs Committee, I am enclosing copies of Fiscal Notes prepared by Gary Jenkins, Director, Audit Division; P. A. Wall, Director, Administrative Services Division; Robert Johnson, Director, Petroleum Revenue Division; Barbara Sorensen, Research Section and a general memorandum from Joseph K. Donohue, Deputy Commissioner of the Department of Revenue regarding the impact of Repeal of the Individual Income Tax concerning the proposed legislation.

Sincerely,

R. D. Stevenson

R. D. Stevenson
Special Assistant

cc: The Honorable John Sackett
Chairman
Senate Finance Committee

Joseph K. Donohue
Deputy Commissioner
Department of Revenue

Gary Jenkins, Director
Audit Division
Department of Revenue

P. A. Wall, Director
Administrative Services Division
Department of Revenue

Robert Johnson, Director
Petroleum Revenue Division
Department of Revenue

Vincent Wright
Research Section
Department of Revenue

04-D2LH

ELEVENTH LEGISLATURE

FISCAL NOTE

I. REQUEST

Bill/Resolution No. SB 474

Title Repealing AS 43.20; Amending AS 43.21

Requested by ______ Date ______

II. FISCAL DETAIL

Agency Affected Revenue

Program Category Affected General Government

BRU, Program, or Subprogram(s) Affected Petroleum Revenue

(Note: If more than one budget component is affected, separate line-item amounts and funding for each component in the analysis section.)

EXPENDITURES (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
100 PERSONAL SERVICES	-0-	-0-	-0-	-0-	-0-	-0-
200 TRAVEL	-0-	-0-	-0-	-0-	-0-	-0-
300 CONTRACTUAL	-0-	-0-	-0-	-0-	-0-	-0-
400 COMMODITIES	-0-	-0-	-0-	-0-	-0-	-0-
500 EQUIPMENT	-0-	-0-	-0-	-0-	-0-	-0-
600 LAND & STRUCTURES	-0-	-0-	-0-	-0-	-0-	-0-
700 GRANTS, CLAIMS, ETC.	-0-	-0-	-0-	-0-	-0-	-0-
TOTAL	-0-	-0-	-0-	-0-	-0-	-0-

(Decline in millions of dollars from otherwise expected receipts)

FUNDING ~~(Thousands of Dollars)~~

GENERAL FUND	(233)	(323)	(534)	(592)	(708)	(742)
FEDERAL FUNDS	-0-	-0-	-0-	-0-	-0-	-0-
OTHER (Specify Fund Source)	-0-	-0-	-0-	-0-	-0-	-0-

POSITIONS

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

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

See, attached memorandum, R. M. Johnson to T. K. Williams, 2/29/80 Note that the fiscal note relates to the initial calendar year of effect of this bill, and the funding impact stated above relates to fiscal years impacted in approximately the same proportion.

IV. DATE 2/29/80

PREPARED BY Robert H. Johnson

AGENCY Department of Revenue

PHONE 276-1363

Original: Legislative Finance

cc: Budget and Management

Prime Sponsor (First Legislator Named)

33-001 (Rev. 12/79)

02-001B (Rev. 10/76)

STATE
of ALASKA

MEMORANDUM

TO: R. D. Stevenson
Special Assistant
Department of Revenue

DATE: February 29, 1980

FILE NO:

TELEPHONE NO:

FROM: Gary L. Jenkins
Director
Audit Division

SUBJECT: Senate Bill No. 474

This bill would repeal the income tax on individuals and corporations and significantly modify the oil and gas income tax. The impact of repealing the individual income tax has previously been set forth for other bills proposing its repeal. A copy of the memorandum prepared showing that impact is attached. The Fiscal Note attached to this memorandum is for the repeal of the corporate income tax only. Therefore, to understand the overall effect of the repeal of chapter 20 of Title 43, the total impact would be that set forth in the attached memorandum plus the attached Fiscal Note.

The revenue impact which would result from enactment of this proposed legislation will be provided by the Research Section of the Department of Revenue.

The Petroleum Revenue Division will provide the effect of the repeal of AS 43.21.

Administrative Services Division will provide the impact on their function which would result from the enactment of this legislation.

Attachment

STATE
of ALASKA

MEMORANDUM

TO: Thomas K. Williams, Commissioner
Department of Revenue

DATE: April 10, 1980

FILE NO:

TELEPHONE NO:

FROM: Robert M. Johnson, Director
Petroleum Revenue Division

SUBJECT: Overview of WPT as a Deduction Under AS 43 21

The analysis of impact or income tax treatment takes the mean royalty receipt figure from our forecasts to derive (A). That figure is then applied to the WPT "formula" with the assumptions of base and decontrolled price of oil applied to derive (B). (B) is subtracted from (A) to get the "change" (C). If (C) is then multiplied by 7 (the WPT applies only to 7/8 of the impacted N.S. crude), the total WPT is derived. That figure multiplied by 9.4% yields the impact of the WPT tax as a deduction (D).

December 1979 Forecast Effect
(Millions of $)

	(A)	(B)	(C)	( )
	Petroleum Royalties			
FY	Without Wintax	With Wintax	Change	Impact on Corporate Income Tax
1980	850.4	839.0	11.4	7.5
1981	1285.0	1068.5	216.5	142.5
1982	1930.3	1355.3	575.0	378.4
1983	2244.8	1512.8	732.0	481.7
1984	2475.7	1657.9	817.8	538.1
1985	2769.3	1860.4	908.9	598.1

These figures demonstrate that as the spread between the base and decontrolled price increases, the impact of the deduction increases. The same rising price of oil of course will increase the gross taxable production income under the tax act.

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

FINANCE DIVISION
POUCH WF–STATE CAPITOL
JUNEAU, ALASKA .11
PHONE: (907) 465-[illegible]5

December 31, 1979

Tom Williams, Commissioner
Alaska Department of Revenue
Pouch S
Juneau, AK 99811

Dear Commissioner Williams:

The Joint Gas Pipeline Committee has requested estimates of revenue to be derived from production of North Slope gas.

I believe your Department could provide some valuable assistance here with little additional trouble or expense.

Specifically, I would like to request that the next quarterly "Petroleum Production Revenue Forecast" of the Petroleum Revenue Division include graphs and tables similar to graphs 1 through 6 and tables 6 through 8 of the September 1979 report for gas only, in addition to the oil and gas totals.

This would take advantage of the state's existing ability to incorporate stochastic estimates of production, prices, conditioning costs, etc. through use of this model.

Although there may be a more desirable method of doing this, it seems to me that it could be done simply enough by zeroing the oil production vector and running the model a second time.

Please let me know if the Department could provide this information.

Yours truly,

Milt Barker

Milt Barker
Fiscal Analyst

cc: Honorable Bill Miles
Honorable Mike Colletta
Co-Chairmen, Joint Gas Pipeline Committee

MB:bf

5-[illegible]LH

FACT SHEET

Windfall Profit Tax
("Crude Oil Windfall Profit Tax of 1980")

The Facts

- In 1978, the Alaska Legislature passed a "special" income tax on the oil industry - the 13th tax increase since the discovery of the Prudhoe Bay field in 1968.

- The income - royalty and taxes - from Prudhoe Bay is totally responsible for the current surplus in the state treasury.

- Decontrol of oil prices at the wellhead will generate billions of dollars of unanticipated revenues to the state in the next few years.

- The price of decontrol is the Windfall Profit Tax. President Carter said decontrol would not be possible without this tax.

- The state's royalty oil dedicated to public purposes - and that of the Alaska Indians and "native corporations" - is exempt from the tax.

- The oil industry will not be able to deduct this tax from its income when paying the Alaska State income tax - thereby having to pay a state tax on taxes paid to the federal government - unless the Alaska law is changed.

- The Windfall Profit Tax is not an income tax, but rather it is an excise or severance tax imposed on a portion of the selling price of crude oil.

- The federal income tax law allows a deduction.

- A deduction for the Windfall Profit Tax could not have been provided initially in the state law since the Windfall Profit Tax did not exist at the time the state law was passed. If the Windfall Profit Tax had existed when the 1978 Alaska tax law was passed, it no doubt would have been considered for inclusion as a deduction at that time.

- The allowance of the deduction will not cause the state to lose revenue - it will realize over twice as much revenue from price decontrol as the producers.

Conclusion

The Windfall Profit Tax is simply another cost of doing business. It is a "severance" tax that must be paid before any income is realized. It is obviously not "income" and should not be taxed in an income tax law. If the deduction is not allowed, the state is, in effect, placing still another tax on the oil industry. THE LAW SHOULD BE CHANGED TO ALLOW THE DEDUCTION.

Assumptions and Calculations

1. \$13.61 per bbl. wellhead price under price controls; \$22.97 per bbl ellhead price with price decontrol and passage of windfall profit tax. Source: Department of Natural Resources royalty value report for January, 1980 production.

2. Zero inflation rate.

3. Prudhoe Bay production 1.5 million bbl per day (45 million bbl per month).

4. State Royalty (under continued price controls)

Monthly production	45,000,000 bbl
times Controlled Wellhead Price	x \$13.61 per bbl
times Royalty Share	x 12½%
	\$76,500,000 per montl

5. Production Taxes (under continued price controls)

Monthly production	45,000,000 bbl
less Royalty Share 12½%	(5,625,000)
	39,375,000 bbl
times Controlled Wellhead Price	x \$13.61 bbl
times Tax Rate	x 12.25%
tim Economic Limit Factor	x .94
	\$61,700,000 per montl

6. Oil and Gas Corporate Income Taxes (under continued price controls) \$402,000,000 ÷ 12 = \$33,500,000 per month. Source: Revenue Sources, FY 1979-81, published by Department of Revenue, Est te for FY 80.

7. Total Monthly State Petroleum Revenues

Royalties (paragraph 4 above)	\$ 76,500,000
Product on Taxes (paragraph 5 above)	61,700,000
Income Taxes (paragraph 5 above)	33,500,000
Total per month	\$171,700,000

8. Distribution of added sales dollar above base price received as a result of price decontrol and windfall profit tax (assumes producer may deduct the windfall profit tax as a direct cost before calculating state income tax).

a. Distribution

	U.S.	Alaska	Producer
Royalty		12.50¢	
Severance Tax		10.08¢	
Windfall Profit Tax	54.19¢		
State Income Tax		2.18¢	
Federal Income Tax	9.68¢		
Producer			11.37¢
	63.87¢	24.76¢	11.37¢

b. How Derived

Royalty	Incremental Dollar	100.00¢
	x Royalty Share	12.50%
		12.50¢
Severance Tax	Incremental Dollar	100.00¢
	less Royalty	- 12.50¢
		87.50¢
	x Statutory Rate	12.25%
		10.72¢
	x Economic Limit Factor	.94
		10.08¢
Windfall Profit Tax	Incremental Dollar	100.00¢
	less Royalty	- 12.50¢
	less Severance Tax	- 10.08¢
		77.42¢
	x Statutory Rate	70%
		54.19¢
Alaska Income Tax		
With deduction for Windfall Profit Tax	Incremental Dollar	100.00¢
	less Royalty	- 12.50¢
	less Severance Tax	- 10.08¢
	less Windfall Profit Tax	- 54.19¢
		23.23¢
	x Statutory Rate	9.40%
		2.18¢
Federal Income Tax	Incremental Dollar	100.00¢
	less Royalty	- 12.50¢
	less Severance Tax	- 10.08¢
	less Windfall Profit Tax	- 54.19¢
	less State Income Tax	- 2.18¢
		21.05¢
	x Statutory Rate	46
		9.86¢

9. Phased price decontrol of Prudhoe Oil beginning January 1, 1980 and ending October, 1981 (4.6% per month), raising weighted average wellhead price from $13.61 per bbl to $22.97 per bbl, an increase of $9.36 per bbl.

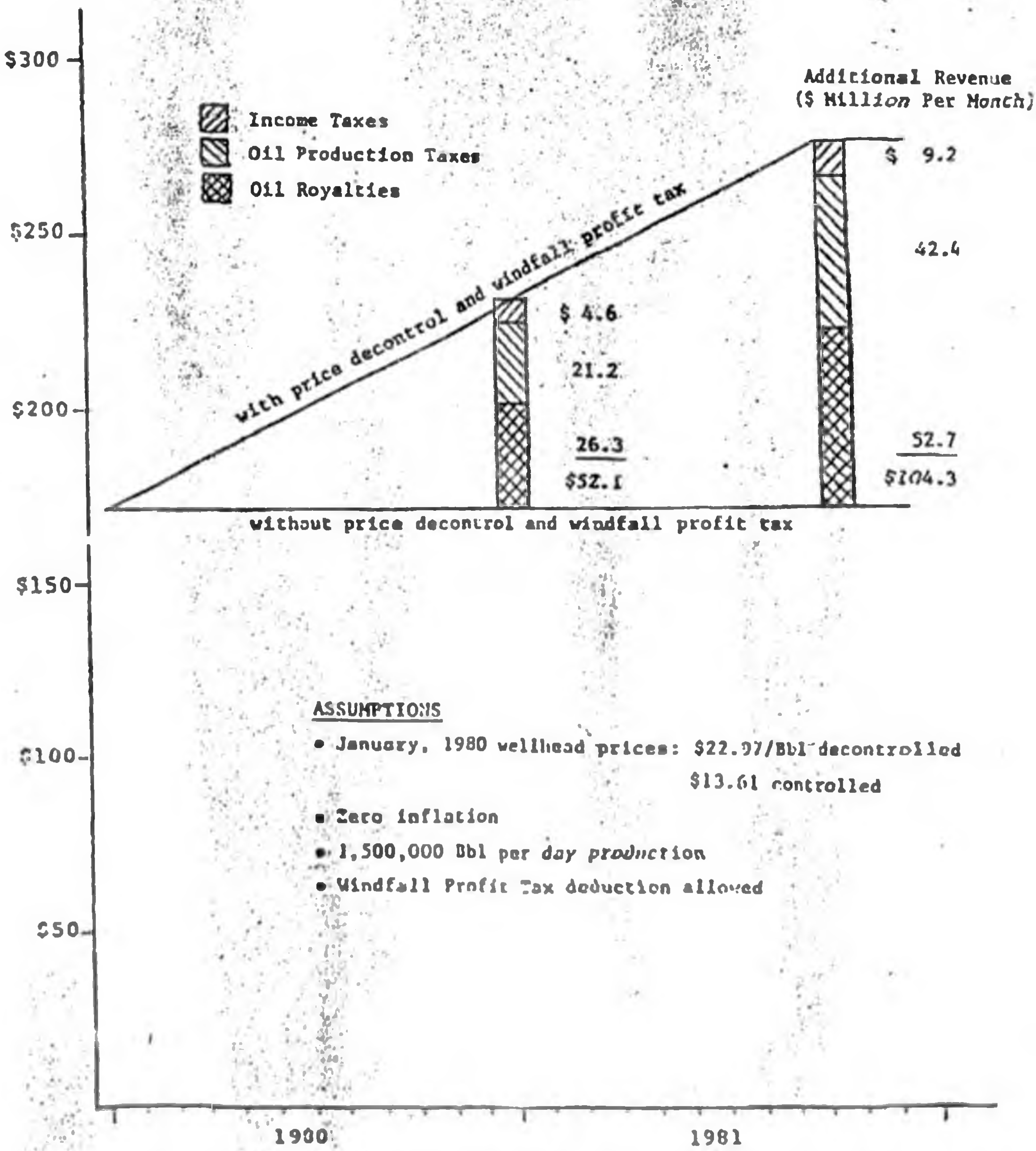
10. Additional monthly state petroleum revenues October, 1981 as a result of price decontrol and windfall profit tax:

Monthly production	45,000,000 bbl
times added sales price	x $9.36 per bbl
Added Gross Revenues	$421,200,000
Added Royalties ($421,200,000 x 12½%)	52,600,000
Added Production Taxes ($421,200,000 x 10.08%)	42,500,000
Added Income Taxes ($421,200,000 x 2.18%)	9,200,000
	$104,300,000

11. October 1981 State Petroleum Revenues

a.	Price Control (no windfall profit tax)	$171,700,000
b.	Added with price decontrol and imposition of windfall profit tax	104,300,000
	Total for month of October, 1981	$276,000,000

State of Alaska
Additional Petroleum Revenues
From Decontrol of Prudhoe Bay Oil



Federal Windfall Profits Tax

Tier I - merged upper and lower tier oil (former "old" and "new")

Tax rate: 70% Majors
50% Independent

Base Price: $12.81/BBL adjusted for inflation

Tier II - Stripper Oil 10 b/d/well

Tax Rate: 60% Major
30% Independent

Base Rate: $15.20/BBL adjusted for inflation

Tier III - New Oil, heavy oil 16° gravity or less, incremental tertiary crude.

Tax Rate: 30% All

Base Price: $16.55 adjusted for inflation

Prudhoe Bay - Sadleochit Oil

Tax Rate: 70%

Base Price: $12.70

Max. Sev. Tax Pass through = 15.8%

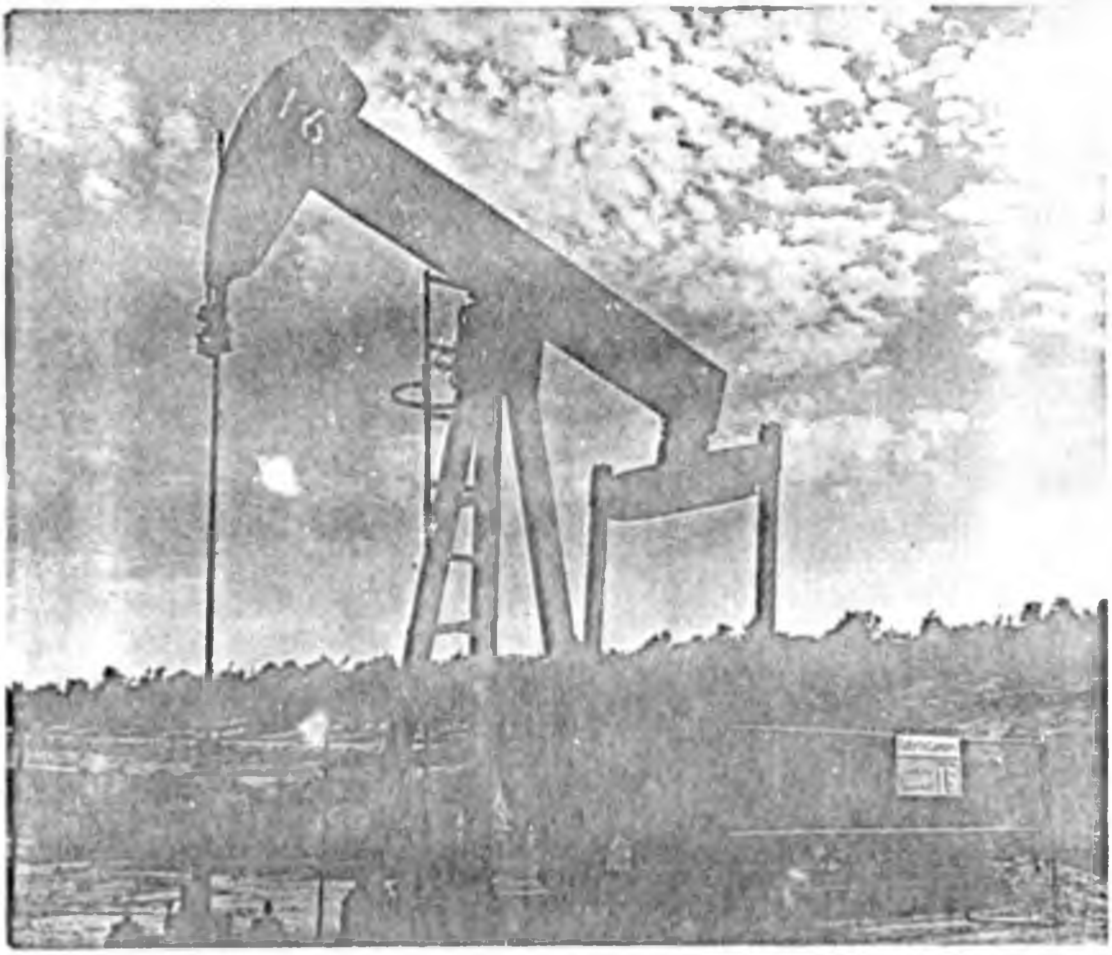
$\frac{15\%}{.95}$ = 15.8%

* 95% = maximum effective sev tax rate

To calculate Income

Take $\frac{[illegible]}{12.25}$ [illegible] (Sev Tax Revenues)

Revc Comm. Dave [illegible]
[illegible]
[illegible]



U.S. OIL PRODUCTION will bear a big new tax burden as a result of the Carter administration's excise levy on revenue flowing from crude price decontrol. Here, Getty Oil Co. 16 Wilcox Fee taps heavy crude reservoir in Poso Creek field, Kern County, Calif.

U.S. House passes excise tax on decontrol revenues

THE House last week passed the excise tax measure on revenue from de-controlled U.S. crude production, sending the $227.7-billion bill to the Senate.

The Senate is expected to vote on the conference-approved bill this week. President Carter has said he will sign the measure.

The Senate vote will be the final step in nearly a year-long legislative struggle over the tax.

Last April Carter announced the phased decontrol of U.S. crude prices but asked Congress to tax away most of the "windfall" to industry in order to finance development of a synthetic fuels industry and other energy conservation/development schemes.

By the late 1980s, the excise tax is expected to result in up to 1.6 million b/d less crude than would have been produced without such a levy.

The final House battle over the bill centered on whether to send the measure back to the conference committee with instructions that independent producers be given better tax treatment.

Rep. Bill Archer (R-Tex.) was the leader of that effort. It would have required House conferees to accept the treatment given independents in the Senate bill — a blanket exemption from any tax on their first 1,000 b/d of production.

After the Archer motion failed by a 227-185 vote, the House voted 302-107 to accept the conference bill.

Another attempt may be made in the Senate to gain better tax treatment for independents. Archer said Sen. Henry Bellmon (R-Okla.) can be expected to lead the fight there.

Although the Senate in December passed its version of the excise tax bill by an overwhelming 74-24 vote, it earlier had voted 53-41 to exempt independent producers' first 1,000 b/d of production (OGJ, Dec. 3, 1979, p. 38).

Some independents hope the same 53-vote majority might send the bill back to the conference committee. As a result, the bill would either die in conference or the House might be persuaded to accept the independents' exemption.

House maneuvering. Archer had predicted a close vote on his motion, which he said would result in $18 billion more in revenues for independents during the 11-year term of the bill.

He said the funds would have resulted in 42,000 additional wells being drilled and 950,000 b/d of additional production by the late 1980s.

Archer doubted whether a small demonstration this week by independents at the Capitol had helped or hurt their cause. "I've heard mixed comments about that," he said.

The Texas congressman said the excise levy is likely never to end.

"Once you put a tax in place and the government begins to depend on those revenues, it becomes very difficult to change."

The House earlier rejected 232-180 a Republican effort to send the bill back to the conference committee with instructions to include a plowback provision—a tax credit of up to 75% for producers to reinvest their profits in exploration.

The House also rejected 215-201 a motion by Rep. Joseph Fisher (D-Va.) which would have required that half of the government's revenue from decontrol be earmarked for production of more energy.

Fisher argued that the current formula, which calls for 60% of the revenues to go for tax cuts and only 15% for energy production/conservation, is a case of mistaken priorities.

The debate. Final arguments on the House floor centered on whether independents needed better tax treatment.

Rep. Al Ullman (D-Ore.), chairman of the House ways and means committee "has given as much to the independents as we possibly can."

Archer argued that it still wasn't enough because independents are the bulwark of the U.S. exploration/production effort.

Archer said the bill "threatens to cripple our production and drive our economy toward chaos. It isn't a plan to produce more oil. It will prevent the production of billions of barrels of oil."

Rep. James R. Jones (D-Okla.) argued that the bill is "bad tax policy and questionable energy policy."

He said it is so complicated and confusing it should be renamed "the lawyers and accountants relief act of 1980."

Jones also pointed out that the tax includes a rollback in price for stripper producers, "the smallest of the small producers."

He said the 30% tax on new and tertiary production "will have an inhibiting effect on the two categories of oil that offer the greatest promise for increasing our oil reserves."

Jones was one of five House members on the conference committee who refused to sign the conference report. The others were Archer, John Duncan (R-Tenn.), Guy Vander Jagt (R-Mich.), and Henson Moore (R-La.). All but Duncan voted against the tax on the House floor.

Industry reaction. Oil industry association leaders were unanimous in criticism of the tax.

The Independent Petroleum Association of America, in a letter to all members of Congress, had warned that the tax "represents disastrous energy policy."

IPAA Pres. C. John Miller said, "It is equally disastrous tax policy because it will inhibit production which is vital and scatter billions in nonproductive government 'giveaways' which will exacerbate an already intolerable inflation."

Miller noted that conferees had planned to use only 15% of the tax revenues to save and produce more energy—and only if Congress passes additional enabling legislation—and 85% for tax cuts and energy aid for low income families.

He warned that, although Congress may make political hay with the revenues in an election year, "when there is another embargo or another situation like Iran, those few dollars in tax refunds will be little comfort against cold homes and gasoline lines."

Miller added "The public and national interest demand that we reverse our eroding domestic energy supply position in the 1980s. I don't know any reputable economist who doesn't believe the 'windfall profits' tax would defeat this objective."

The Independent Petroleum Association of Mountain States, Denver, said the tax bill "takes a pound of flesh from the heart of the only industry the public has in this country to keep the energy pump beating."

Kye Trout, Ipams president, said, "The sad part of it is that little if any of the funds confiscated by this sham will be used to create jobs and economic benefit to alleviate our increasingly worsening energy and economic situation.

"Instead, it will be frittered away on superficial government programs designed to be used as chips in the games politicians play."

Charles DiBona, president of the American Petroleum Institute, said there is little hope of alteration of the bill on the Senate floor.

"As a consequence of the 'windfall profits' tax, the amount of oil that we won't produce will be some 2 million b/d (in the late 1980s)," he said.

The tax. The tax is complicated and will force producers to retain professional help in determining tax liabilities.

IPAA and some private organizations have been holding seminars in oil producing regions to acquaint producers with the basic provisions of the tax.

The tax took effect Mar. 1 atop existing crude price control regulations. Although the price controls are to expire in 1981, they will remain the basis for the excise tax.

For instance, production that was lower tier oil under price controls will continue to be defined and taxed as lower tier under the excise tax.

This will require producers to maintain their accounting and production records developed for crude price control regulations, although those rules are to expire.

The excise tax sets forth three main categories of taxable crude:

- Tier I—All oil designated as lower and upper tier production under existing price controls.
- Tier II—Stripper well production.
- Tier III—Newly discovered oil, heavy oil of 16°-gravity or less, and incremental tertiary oil.

Special tax rules were drafted for newly discovered Alaskan production, tertiary oil, and oil production owned by state and local governments, Indian tribes, charitable medical institutions, and schools and universities.

The amount subject to the excise tax is the difference between selling price of the crude and the sum of the adjusted base price plus the state severance tax adjustment. That difference is taxed at the appropriate rate for the particular category of crude.

The tax can't exceed 90% of the net income from a barrel of oil. The net income figure is determined by dividing the yearly taxable income from the property by the number of barrels of taxable crude produced from the property in the taxable year.

For this purpose, "property" is defined the same as "income property" under the tax code, not the definition used in price control regulations.

The tax applies to each barrel of oil sold from the lease and must be paid by the producer, although in most instances it will be withheld by the first purchaser.

The taxable period is a calendar quarter.

Because it is an excise tax, the tax is deductible from gross income subject to federal income tax. Independent producers and royalty owners are allowed full percentage depletion on revenues subject to the excise tax.

Tier I Tax. The basic tax rate for Tier I production is 70% for integrated companies and all royalty owners and 50% for independent producers.

Tier I production consists of all lower and upper tier oil under price controls, upper tier oil released to the market price, marginal property production, and heavy oil that doesn't meet the heavy oil definition for tax purposes—that is, oil between 16° and 20°-gravity.

IPAA notes that "consequently, production from a single property may fall within several different categories for crude price purposes and several different categories for tax purposes.

"For example, a barrel of oil which is 19°-gravity might be released to market level for pricing purposes but still be considered either lower tier or upper tier oil for excise tax purposes."

The base price for Tier I production is the May 1979 Department of Energy ceiling price plus an adjustment for inflation and minus 21¢.

The base price for Tier I has been determined to average $12.81/bbl as of May 1979.

The adjusted base price for each property is determined in accordance with a formula specified in the bill for the first 6 months and thereafter by Internal Revenue Service regulations.

The inflation adjustment factor for increasing base prices in any taxable period will be the gross national product (GNP) deflator for the calendar quarter 2 quarters earlier than the taxable quarter in question, divided by the GNP deflator for June 1979.

Tier II tax. The Tier II tax, covering stripper oil, is a 60% tax for royalty owners and major producers and a 30% tax for independents.

"Stripper oil" carries the same definition as under crude pricing regulations: production from a property that averages not more than 10 b/d/well.

However, any property that once was designated stripper but now produces more than 10 b/d/well still is considered a stripper lease.

Under a temporary rule, producers will compute Tier II base prices using a formula based on their December 1979 postings corrected to a presumed national average and adjusted for inflation. Average nationwide Tier II base price for December 1979 is estimated at $15.20/bbl.

The inflation adjustment factor is the GNP deflator for the 2 calendar quarters earlier than the taxable period, divided by 163.79.

This temporary base price rule will be replaced in October, when the Treasury Department must publish a permanent base price rule for stripper oil.

Tier III tax. All producers will pay the same tax rate for Tier III production—newly discovered oil, heavy crude of 16° gravity or less, and incremental tertiary crude.

Tier III base prices will be calculated similarly to Tier II prices. But the presumed national December 1979 price average is higher, and the estimated average Tier III base price for that month is $16.55/bbl.

In addition, the inflation adjustment for Tier III involves a 2%/year "kicker" not included in Tier II.

"Newly discovered oil" is defined the same for tax and pricing purposes. It is oil produced from an onshore property which had no production during 1978 or production from an offshore property leased after Jan. 1, 1979.

"Heavy oil" is defined differently for excise tax and crude pricing purposes.

For tax purposes, it includes all production from a property where during the last month of production prior to July 1979 all crude had a weighted average gravity of 16° or less, corrected to 60° F.

It also includes properties with production of that average gravity during the taxable period.

IPAA says, "This means that if a property qualifies under (the first provision) by reason of having all production with an average gravity of 16° or less in the last month prior to July 1979 during which there was production, all future production from such property will be eligible as heavy oil.

"But if the property won't qualify on that basis because the property did not produce prior to July 1979, or during the last production month prior to July 1979 production did not average 16° or less, then during any calendar quarter in which all of the production from the property averages 16° or less, it will qualify.

"Therefore, a property may go in

The tax at a glance

Category of crude	Tax treatment
Tier I—merged upper and lower tiers (former "old" and "new" oil)	Independents' first 1,000 b/d: 50% tax Majors: 70% tax Both use $12.81/bbl base price, adjusted for inflation
Tier II—stripper	Independents' first 1,000 b/d: 30% tax Majors: 50% tax Both use $15.20/bbl base price adjusted for inflation, quality, and location.
Tier III—newly discovered incremental tertiary, and heavy oil of 16°-gravity or less	30% tax on selling price above $16.55/bbl, adjusted for inflation plus 2%, quality, and location.
Prudhoe Bay field Sadlerochit	70% tax on the selling price above $12.70/bbl, adjusted for inflation.
Newly discovered Alaskan north of Arctic Circle and north of Alaskan-Aleutian range and 75 miles from trans-Alaska pipeline.	Exempt.

and out of the heavy oil classification for crude tax purposes. This is distinctly different from the definition of 'heavy oil' for crude oil pricing purposes."

That definition is "all crude oil produced from a property, but only if, during the last month prior to July 1979 in which crude oil was produced and sold from that property, such crude oil had weighted average gravity of 20° or less, corrected to 60° F."

IPAA notes that "under the pricing definition, a property which did not qualify in a month prior to July 1979 cannot qualify in the future no matter what develops."

The definition of "incremental tertiary production" for tax purposes also is significantly different than for pricing purposes.

Under the excise tax, the incremental tertiary project may be the result of certification by a government regulatory authority or by self-certification by the producer.

Under self-certification, a petroleum engineer must verify that the project involves one or more tertiary recovery methods which are applied in accordance with sound engineering principles.

The engineer must state that the methods can be expected to result "in more than an insignificant increase in total ultimate recovery above that which otherwise could be expected," and the project's beginning date is after May 1979.

Current crude pricing rules define "incremental production" as oil produced beyond what normally would have been produced without application of the enhanced recovery technique.

The excise tax definition is more generous. It defines incremental oil as production in excess of the property's base production control level (BPCL) declined at 1%/month for each month since 1978 prior to initiation of the project, and 2.5%/month for each month thereafter, or the actual decline if it's greater.

The incremental tertiary provision will apply to new projects and significant expansions of existing projects.

The front end tertiary production (lower tier oil released to market levels to finance initial tertiary investments) will be exempt from the tax if 50% or more of the interest in the project is owned by independent producers. Otherwise, the Tier 1 tax applies. This exemption ends Sept. 30, 1981.

Other rules. The tax will be withheld by the first purchaser of the crude or the operator of the property and deposited in a trust account. The purchaser must file quarterly returns and provide producers and royalty owners annual statements of their tax liabilities which would be included with the producers' income tax returns.

Working interest owners may select any party as the "operator" for excise tax purposes, although the "operator" needn't be the operator for producing purposes. Different persons may be named the "operator" for different parts of the same property.

The different tax rates for various categories of oil and producers will result in monthly adjustments in withholding rates for producers and properties.

Large companies must make semimonthly estimated tax payments for oil purchased and produced. Independent refiners with delayed payment contracts must make tax deposits within 60 days after the month of purchase. Others must make deposits 45 days after the end of the month of purchase. In most cases the latter category will include independent producers acting as operators.

Working interest owners can't use their option of designating special "operators" for tax purposes to secure less-frequent tax payments. The bill says changes of "operator" status to parties other than integrated companies don't change tax payment schedules.

Although the excise tax is premised on DOE definitions and rules, it will be administered and enforced by the Treasury Department and the IRS.

DOE will assist Treasury and IRS and will certify qualified tertiary projects and release of front-end tertiary incentive production.

Court appeals will follow the route of income tax cases, with jurisdiction lying in Tax Court and U.S. District Courts. Appeals will go to the U.S. Courts of Appeal rather than the Temporary Emergency Court of Appeals, which was created to hear crude oil pricing cases.

Willful failure to comply with provisions of the excise tax act will be a misdemeanor punishable by at most a $10,000 fine, 1 year in prison, or both.

The burden of proof of establishing the entitlement to preferential tax rates is on the taxpayer.

Rules for independents. The definition of "independent producers" is about the same for the excise tax as it is for percentage depletion purposes: Gross retail sales may not exceed $5 million/year, and the independent can't own a refinery running more than 50,000 b/d of crude.

The only significant difference is that only working interests existing Jan. 1, 1980, are eligible for independent producer status under the excise tax. Royalty owners are taxed the same as major oil companies.

The conferees decided that overriding royalties, negotiated by agreements in effect on Feb. 20, 1980, will be eligible for independent status when the royalty is converted to a working interest.

The special tax rates given independents apply to the first 1,000 b/d of lower tier, upper tier, and stripper production. If less than 1,000 b/d is produced, all production would get the special tax rates. If more than 1,000 b/d is produced, the excess would be charged the regular tax rate.

The bill prorates the 1,000 b/d over all three categories.

The allocation of the 1,000 b/d between related persons or businesses under common control is treated much like percentage depletion. One exception is that a producer owning 50% or more of a corporation must allocate a single 1,000 b/d between himself and the corporation.

An independent with less than 1,000 b/d of production may transfer all or part of his production, and the production will remain qualified for the independent exemption.

However, a producer having more than 1,000 b/d of qualified production as of Jan. 1, 1980, or later, may not transfer any part of it without the transferred production losing the independents' tax rate, even if the transferee is an independent.

Production owned by royalty owners or major oil companies doesn't become eligible for the independent exemption if it is sold to an independent.

Other categories. House-Senate conferees agreed to tax oil from the Sadlerochit reservoir in Prudhoe Bay field the same as Tier 1 oil—with a 70% tax rate—but set the base price at $12.70/bbl rather than $12.81.

Other oil produced north of the Arctic Circle is exempt from the tax, as is oil produced north of the Alaskan-Aleutian mountain range and more than 75 miles from the trans-Alaskan oil pipeline.

Oil produced on land held by Indian tribes will be exempt from the tax. Oil from land granted to Alaskan native regional corporations by the Native Claims Settlement Act will be exempt from the tax until 1992.

Production from state and local government land is exempt from the tax if the revenues are used for any public purpose.

And production from land owned by charitable medical facilities, educational institutions, or churches is exempt from the tax if the land was owned by such an institution on Jan. 21, 1980, and as long as the proceeds from the oil production are dedicated to medical or educational purposes.

The conference agreement allows producers to deduct state severance taxes from revenue subject to the excise tax.

It permits deduction of any increase in state severance taxes enacted after Mar. 31, 1979, only if the increase applies equally to the entire price of the barrel of oil and only to the extent that the total rate of severance tax imposed by the state doesn't exceed 15%.

Business tax credits. The conference bill provides $8.3 billion in business tax incentives, of which $6.2 billion is in energy tax credits.

It increases the 10% refundable tax credit for investment in solar or wind energy equipment to 15% and extends the time limit from 1982 to 1985. The bill adds to the list of eligible solar energy properties equipment that uses solar energy to provide industrial, agricultural, or commercial process heat.

The refundable feature of the solar and wind energy tax credit was repealed, though.

The present 10% nonrefundable energy tax credit for equipment to produce, distribute, or use geothermal energy was increased to 15% and extended from 1982 to 1985.

The bill provides a 15% tax credit through 1985 for ocean thermal equipment to be installed at two sites to be selected by the Treasury Department. The equipment would produce electricity by using ocean temperature variations.

A nonrefundable credit was granted for production and sale of alternative energy sources such as shale oil, synthetic fuels from coal and biomass, tar sands, and processed wood.

The credit is $3/bbl of oil equivalent, measured on a BTU basis and adjusted for inflation. It is allowed for alternative fuel domestically produced and sold by Jan. 1, 1990, and phases out as the average price of domestic oil rises to $29.50/bbl.

The bill sets special rules for gas from geopressured brines, Devonian shale, coal seams, and tight formations.

It keys the reference price to other natural gas prices.

Other incentives are offered for small scale hydroelectric facilities, cogeneration equipment, biomass equipment, intercity buses, electrolytic cells, petroleum coke and pitch boilers, and coke and coke gas equipment.

Breakout of decontrolled production revenues

Category	Billion $	Percent
Excise tax (conference bill)	227.7	23
Federal income tax and royalties	357.7	35
State and local taxes and royalties	118.5	12
Total taxes and royalties	703.9	70
Additional revenue to producers	302.7	30
Grand total	1,006.6	100

Source: Democratic Study Group.

The conference agreement extends through 1992 the present exemption for gasohol from the 4¢/gal federal gasoline excise tax.

A comparable credit was voted for alcohol fuels used in industrial plants and on farms.

The conference agreement contains several provisions relating to the use of industrial development bonds to finance solid waste disposal facilities, hydroelectric power plants, and renewable energy equipment.

It provides for $600 million in residential energy tax credits by 1990.

It also authorizes $3.1 billion for fiscal 1981 for a program of grants to the states to provide assistance to lower income families for heating and cooling costs.

Households will be eligible if their incomes were less than $11,600/year for a family of four.

LIFO, imports. Two miscellaneous provisions in the tax bill deal with oil company accounting methods and import quotas.

The conference bill amends the Trade Expansion Act of 1962 to allow Congress to override a presidental decision to impose oil import quotas by enacting a joint resolution disapproving such executive action.

The joint resolution would be considered under normal legislative procedures.

The bill gives companies a break on taxes they pay on profits from forced inventory reductions. Most oil companies currently use the LIFO (last in, first out) method of computing profit from sale of inventory stock.

DOE has authority to order oil companies to reduce their inventories of oil. If that or a major foreign trade interruption occurs, companies can apply under the excise tax bill for a refund of taxes paid on the LIFO inventory profits of such a sale.

To qualify, the liquidated inventory must be replaced within 3 years. The Treasury Department must designate in advance those situations in which the provision will apply. It could result in a revenue loss to the Treasury of $250 million by 1990.

Background of tax. President Carter handed the oil industry some "good news, bad news" last April in the midst of the crude supply shortage caused by cutbacks in Iranian production.

He announced phased decontrol of domestic production, which had been under price controls since 1973. The controls were imposed to rein domestic crude prices in spite of increases in the price of crude from members of the Organization of Petroleum Exporting Countries.

As a result of decontrol, oil produced in the U.S. will rise to the world price, yielding companies $1 trillion or more in extra revenues in the 1980s, but only $442 billion after taxes.

Carter proposed a $300 billion excise tax to trim that "windfall" to the oil firms, and the House quickly agreed to a $278 billion tax which gave Carter most of what he had requested.

However, the Senate slowly deliberated the question, balancing the benefits of tax revenues with their effects on production. It finally passed a $177-billion tax bill.

The Senate bill taxed pre-1973 oil higher than the House measure did. But the Senate bill involved a lower tax on newly discovered, tertiary, and heavy oil production and exempted much of the production of independents.

The conferees split the tax revenue difference down the middle, opting for a $227-billion tax which would phase out over 33 months beginning in 1988 or when total revenues reach the $227 billion goal, whichever is later.

Even if the target isn't reached, phaseout will begin in January 1991.

Political pragmatists say, however, it's not likely Congress will permit the tax ever to expire.

—Patrick Crow
Congressional Editor

not an official proposal

DRAFT
01/16/80

BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

ELEVENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled "An Act amending the Oil and Gas Corporate Income Tax Act; and providing for an effective date."

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

*Section 1. AS 43.21.010 is amended to read:

Sec. 43.21.010. APPLICATION This chapter applies to every corporation doing business in the state which derives income from the production of oil or gas from a lease or property in [OR DIRECTLY ASSOCIATED WITH] the state, or from the pipeline transportation of oil or gas in the state. The tax calculated under this chapter is measured by the total taxable income of the corporation as defined in secs. 20 - 40 of this chapter and is determined at the rates established under AS 43.20.011(e).

no nexus for offshore (wholly) activities, not doing business in Alaska. Technical point

*Section 2. AS 43.21.020(c) is amended as follows:

now done under std accounting practice

(7) interest expense [NOT CAPITALIZED] of the corporation, to the extent that it does not exceed that portion of the total interest paid by the consolidated business of which the corporation is a part, determined by multiplying the total interest reduced by intercompany transactions within the consolidated business by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used directly in the production of oil or gas from a lease or property in the state and the denominator of which is the value of all real and tangible personal property of the consolidated business.

re Cook Inlet

(10) the costs of permanently terminating operations, site restoration, or removing part or all of the wells, facilities and equipment in a production facility, in an amount which equals

(A) a portion of the unreimbursed, estimated termination and removal cost in a year prior to actual termination and removal according to any reasonable method as the department may by regulation establish; or

(B) the unreimbursed termination, site restoration, and removal costs that are actually inccurred that year, offset by the salvage value (if any) of the removed facilities and equipment and further offset to the extent of any amounts allowed to be taken prior to actual termination, site restoration and removal under this paragraph and taken by the taxpayer.

*Section 3. AS 43.21.030 is amended to read:

Sec. 43.21.030. DETERMINATION OF INCOME FROM OIL AND GAS PIPELINE TRANSPORTATION. (a) Except as provided in (c) and (d) of this section, taxable income attributable to the transportation of oil in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission or its successors as net operating income, less those portions of interest and general administrative expense attributable to the pipeline transportation of oil in the state, except that taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of oil in the state.

allows accelerated depreciation for the pipeline

(b) Except as provided in (c) and (d) of this section, taxable income attributable to the transportation of natural gas in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission as net operating income less that portion of interest and general administrative expense attributable to pipeline transportation in the state, except that the taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of natural gas in the state.

(d) The taxpayer shall calculate depreciation using any reasonable method as the department may by regulation establish in lieu of the amount reported to the Federal Energy Regulatory Commission.

how does FERC do it now

*Section 4. AS 43.21.040 is amended to read:

Sec. 43.21.040. DETERMINATION OF INCOME FROM ACTIVITIES OTHER THAN OIL AND GAS PRODUCTION OR PIPELINE TRANSPORTATION. (a) Taxable income of a corporation subject to this chapter from activities in this state other than the production of oil or gas from a lease or property in the state or the pipeline transportation of oil or gas in the state shall be determined in accordance with the method established in art. IV of AS 43.19.010 and in AS 43.20.071, as modified by (b) - [(e)] (f) of this section.

The Alaska portion of world-wide income

(b) The total taxable income of the consolidated business shall be the net income determined and certified by an independent certified public accountant for the purposes of a report to shareholders covering its earnings and profits for the taxable year (calculated without regard to any taxes on or measured by net income), less [THE TAXABLE INCOME OF THE CORPORATION AS DETERMINED UNDER SECS. 20 AND 30 OF THIS CHAPTER.] the earnings and profits of the consolidated business gained directly from oil and gas production and pipeline transportation.

deducts pipeline income

(c) The numerator and denominator of the property factor, of the payroll factor and of the sales factor shall be calculated without reference to that portion of property, payroll or sales directly related to the production of oil or gas from a lease of property in the state or the pipeline transportation of oil or gas in the state.

(d) Compensation earned by employees of the consolidated business who are employed in the United States but not in any state shall be included in the numerator of the payroll factor if the employees are directly supplied from a base of operations maintained in this state.

(e) The value of oil or gas production facilities or other properties of the consolidated business which are located in the United States but not in any state shall be included in the numerator of the property factor if the property is serviced or supplied from a base of operations maintained in the state or if that property relies on onshore facilities in this state for storage of the oil or gas produced.

(f) The value attributed to vessels transporting Alaskan oil or gas of the consolidated business which are not owned or effectively owned by the consolidated business shall be excluded from the property factor.

*Section 5. AS 43.21.120 is amended as follows:

Sec. 43.21.120. DEFINITIONS. Unless the context requires otherwise, the definitions contained in AS 43.55.140 are applicable to this chapter. In addition, in this chapter

(2) "consolidated business" means a corporation or group of corporations having [AT LEAST] more than 50 percent common ownership, direct or indirect, or a group of corporations in which there is common control either direct or indirect as evidenced by any arrangement, contract or agreement.

*Section 6. This Act applies to income earned and deductions paid or incurred after December 31, 1979.

*Section 7. This Act takes effect July 1, 1980.

15 AAC 12.120 VALUE AT THE POINT OF PRODUCTION. (a) This section applies to all oil and gas produced in the state on a property or lease whether or not the oil or gas is removed from the property or lease, less any oil or gas the ownership or right to which is exempt from state taxation.

(b) The gross value at the point of production for a taxpayer's oil or gas equals the sales price under sec. 122 of this chapter for that oil or gas, less the taxpayer's reasonable costs of transportation under secs. 130 and 132 of this chapter for that oil or gas from its point of production to its sales delivery point and also less the taxpayer's reasonable costs incurred downstream of the point of production for processing, conditioning and preparing gas and gas plant liquids for sale; except

(1) when (c) of this section applies, in which case the gross value at the point of production for that oil or gas equals the prevailing value under sec. 124 of this chapter, or

(2) when the gross value at the point of production would yield a value of less than $.60 per barrel of taxable oil crude oil or $.80 per barrel of taxable new crude oil or $.64 per Mcf of taxable gas, the gross value at the point of production equals the applicable minimum amount, or

(3) when the gross value at the point of production for the taxpayer's oil or gas would exceed the applicable maximum lawful price (if any) set by the U.S. Department of Energy, the Federal Energy Regulatory Commission, another governmental agency or a court of law, adjusted for any changes in value due to any processing, conditioning and transportation of that oil or gas occurring between its point of production and the point at which the applicable maximum lawful price is effective, in which case the gross value at the point of production equals that applicable maximum lawful price as adjusted for such changes in value.

(c) Instead of the sales price, the prevailing value under sec. 124 of this chapter must be used in determining the gross value at the point of production for a taxpayer's oil or gas if

(1) the sales price for that oil or gas is substantially lower (determined by analyzing the cash value of the consideration received for that oil or gas and taking into account the degree of difference between the prevailing value and the sales price for that oil or gas, the quantity of oil or gas involved in the transaction and the duration of the transaction) than the prevailing value for oil or gas of like kind, character, and quality from the same field or area being sold in significant quantities at the same or corresponding sales delivery points in the same market or in a comparable market if there are no such other sales in significant quantities in the same market; and

(2) one or more of the following conditions exist:

(A) the contract under which the taxpayer's oil or gas is being sold or exchanged is executed or renegotiated after December 31, 1979 and either sets a price for that oil or gas without adjustments tied to market conditions or does not provide for subsequent renegotiation of prices at market rates,

(B) the contract sets a price which does not reasonably reflect market conditions for production from that field or area prevailing at the time the contract is executed or renegotiated,

(C) the contract price under which the taxpayer's oil or gas is being sold or exchanged reflects an unusually weak bargaining position on the taxpayer's part due to circumstances which the taxpayer could reasonably have foreseen and taken steps to ameliorate or avoid,

(D) the circumstances relating to the disposition of the taxpayer's oil or gas show fraud or an intent to evade taxes.

(d) For valuation purposes, production of oil or gas does not include oil or gas

(1) used or unavoidably lost in production operations on the lease or property, or

(2) flared in amounts authorized for s ty by the Alask. Oil and Gas Conservation Commission under AS 31.05.170(11)(H), or

(3) injected into a reservoir in the course of operations in the same field for purposes of repressuring or conservation.

(e) As used in this section and secs. 122, 124, and 900 of this chapter, the terms "exchange" and "exchanged" do not include transactions where a producer transfers oil to a third party at the Port of Valdez or at another port in Alaska for purposes of operational necessity or convenience in what otherwise would be a bona fide, arm's-length exchange but for the fact that at the time of the particular transfer the producer expects subsequently to receive a like amount of similar quality oil from that third party at the same port. Such a transfer to a third party and the subsequent transfer from the third party, when they occur, must be disregarded and the oil subject to that transfer must be regarded as if it had remained in the possession of the transferring producer pending final disposition of that oil. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.122. SALES PRICE. (a) The sales price for purposes of this chapter for first sales of a taxpayer's oil or gas to one or more third parties is the cash value of the full consideration being given in receipt for that oil or gas in those sales.

(b) If a taxpayer's oil or gas is being sold to an affiliate of that taxpayer (as opposed to being transferred from one division to another within the same corporate person), the sales price of that oil or gas for purposes of this chapter is the greater of

(1) the cash value of the full consideration given in receipt for the oil or gas so sold, and

(2) the price attributable to that sale which is entered on the taxpayer's books in accordance with generally accepted accounting principles, consistently applied.

(c) If a taxpayer's oil or gas is retained by the taxpayer or is transferred from the production division to another division within the same corporate person, the sales price of that oil or gas for purposes of this chapter is the price attributable to that oil or gas which is entered on the taxpayer's books in accordance with generally accepted accounting principles, consistently applied.

(d) If a taxpayer exchanges oil or gas with a third party, the sales price of that oil or gas for purposes of this chapter is

(1) the price prescribed in the exchange agreement for the taxpayer's oil or gas for purposes of settling accounts and cashing out any net exchange balances in the taxpayer's favor (to illustrate what is meant by a net exchange balance in the taxpayer's favor, suppose the exchange is for oil on a barrel-for-barrel basis and the taxpayer's volume to the third party exceeds the volume received from the third party: the amount of that excess would be the net exchange balance in the taxpayer's favor); or

(2) if there is no such price prescribed in the exchange agreement, the price attributable to the oil or gas received by the taxpayer which is entered on the taxpayer's books in accordance with generally accepted accounting principles, consistently applied. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.124. PREVAILING VALUE. (a) For a taxpayer's oil, the prevailing value for purposes of this chapter equals the arithmetic average acquisition cost C.I.F. at the refinery inlet in the same market as that in which the taxpayer's (Alaskan) oil is refined for any three (at the taxpayer's choice) of four market crudes; less the taxpayer's reasonable costs of transportation under secs. 130 and 132 of this chapter for its oil from the point of production to ship's rail in that market. The four marker crudes are Iranian Heavy, Arabian Light, Arabian Medium and Mexican

Isthumus. The taxpayer may choose the three marker crudes specified in this subsection. That choice of the taxpayer shall apply to the initial month for which that choice is made and to all subsequent months; provided, however, that choice may be changed for a subsequent month by the taxpayer upon approval by the department. For each of the three chosen marker crudes, its respective acquisition cost C.I.F. at the refinery inlet in that market equals the sum of

(1) its respective official government sales price (with adjustments for differentials and surcharges) appearing in the latest Platt's Oilgram Price Report published on or before the last day of a month; plus

(2) the marker crude's respective tanker transportation cost from its port of origin in Iran, Arabia or Mexico to ship's rail in the same market as that in which the taxpayer's (Alaskan) oil is refined, to be calculated by multiplying the London Tanker Broker's average freight rate assessment ("AFRA") applicable to that voyage during that month for AFRA LR 2 (long range 2) oil tankers, by the most recently published Worldscale rate for that voyage; and plus

(3) any canal tolls and expenses not included in the AFRA for that voyage.

(b) For a taxpayer's gas, the prevailing value for purposes of this chapter is calculated by subtracting the taxpayer's reasonable costs of transportation under secs. 130 and 132 of this chapter for its gas from the point of production to the sales delivery point in that market and also the taxpayer's reasonable costs incurred downstream of the point of production for processing, conditioning, and preparing gas and gas plant liquids for sale from

(1) the volume-weighted average of the prices received under the terms of sales contracts which have been entered into or whose pricing provisions have been amended during the tax year or the two preceeding years for significant quantities at the sales delivery points within the same market for that production by the taxpayer in arm's-length sales transactions for like kind, character, and quality Alaskan gas produced during the month; or

(2) if the taxpayer makes no arm's-length sales of significant quantities at the sales delivery points within the same market for like kind, character, and quality Alaskan gas produced during the month, the volume-weighted average of the prices being given and received under the terms of arm's-length sales contracts (whether between third parties or not) which have been entered into or whose pricing provisions have been amended during the tax year or the two preceeding years for significant quantities of gas from the same field as the taxpayer's gas (or if there are no such contracts for that field, the counterparts of those contracts in the nearest field to that field), with appropriate adjustments for differences, if any, in kind, character, and quality between gas sold under the reference sales contracts and the taxpayer's gas. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.130. CHOICE OF METHODS FOR DETERMINING REASONABLE COST OF TRANSPORTATION. (a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in sec. 132(a) and (b) of this chapter.

(b) The reasonable cost of transportation is the fair market value as defined in sec. 132 of this chapter when all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transporation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.132. CALCULATION OF REASONABLE COSTS OF TRANSPORTATION. (a) Reasonable costs of transportation are to be calculated from the point of production to the sales delivery point.

(b) Actual costs of transportation for purposes of sec. 130(a) of this chapter are:

(1) when the transportation of oil or gas is by a regulated carrier, the tariff on file with FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) when transportation of oil is by a tanker or other vessel that is not owned or effectively owned by the taxpayer of that oil,

(A) for a single voyage charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the taxpayer, plus the positioning cost, if any, borne by the taxpayer for that vessel; or

(B) for a consecutive voyage charter or a time charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transporation during the term of the charter and which are borne by the taxpayer, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter) if any, borne by the taxpayer for that vessel; or

(C) for a contract of affreightment, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee which are incurred with respect to that transportation during the term of the contract of affreightment and which are borne by the taxpayer;

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by the taxpayer of that oil, the taxpayer's actual cost for that transportation, which is the sum of:

(A) voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(C) depreciation of the vessel; if the vessel is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this paragraph,

(i) "acquisition costs" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, but not including costs of improvements made after the date the vessel is placed in service by or on behalf of the taxpayer, and

(ii) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(iii) depreciation of the LNG transportation facility; if the facility is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iv) an amount which, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, and "expected life" means the period of time used to calculate depreciation under (iii) of this subparagraph;

(5) when the transportation of oil or gas is by a non-regulated pipeline facility that is not owned or effectively owned by the producer of that oil or gas, the transportation fee is specified in the contract plus any other costs not included in the fee with respect to that transportation which are borne by the producer;

(6) when the transportation of oil or gas is by a non-regulated pipeline facility that is owned or effectively owned by the producer of that oil or gas, an amount equal to that which would have been reported to the FERC or other regulatory agency having jurisdiction applicable to the transportation of oil or gas under (1) of this subsection, had the transportation been, in fact, under the jurisdiction of FERC or other regulatory agency for the tax reporting period.

(c) Reasonable cost of transportation under sec. 130 of this chapter is fair market value. Fair market value of transportation is to be determined:

(1) for shipments of oil, on the basis of third party charters (that is, time charters in which the taxpayer does not own or effectively own the vessel) of one year or more, plus regulated transportation costs determined under (b)(1) of this section; two vessels will be considered like vessels for purposes of comparing like transporation under this chapter if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels; or

(2) for shipments of gas as LNG, on the basis of third party charters or leases (that is, charters or leases in which the taxpayer does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the department for like LNG transportation facilities, plus regulated transportation costs determined under (b)(1) of this section.

(d) If a taxpayer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the taxpayer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it has remained the taxpayer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the taxpayer were the shipper. This subsection does not apply if the taxpayer's expected repurchase does not in fact occur.

(e) For purposes of this section, "voyage and port costs" for a vessel are

(1) costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and

dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid to third-party insurers, minor cargo losses or measuring differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be pro-rated equally among vessels, for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the taxpayer, and other reasonable costs associated with the operation or maintenance (or both) of the vessel; and

(2) in addition to the costs listed in (1) of this subsection, in the case of catastrophic loss or damage of a vessel transporting oil or LNG from Alaska or enroute to Alaska to take on oil or LNG, a portion of the loss (for loss or damage to the ship, for injury or loss of her captain or crew and for damage and clean-up due to spillage of part or all of her cargo, but not for the loss of the cargo itself) which is borne by the shipper as the result of that catastrophic loss or damage and which is not reimbursed by insurance or by a third party; this portion of the less is determined by dividing the unreimbursed liability on the basis of dead-weight tonnage among the vessels owned, effectively owned or chartered by the shipper to transport oil or LNG (whichever was lost) from Alaska.

(f) A taxpayer "effectively owns", has "effective ownership" or "effectively has an ownership interest" in a vessel, LNG transportation facility, or non-regulated pipeline facility for purposes of this section, if

(1) the vessel, LNG transportation facility, or non-regulated pipeline facility is owned by another person comprising part of a consolidated business in which the taxpayer is also a part; or

(2) the vessel, LNG transportation facility, or non-regulated pipeline facility is the subject of a capital lease in which the taxpayer or another person comprising part of a consolidated business in which the taxpayer is also a part, is the lessee; or

(3) the vessel, LNG transportation facility, or non-regulated pipeline facility was built to the account of the taxpayer (or another person comprising part of the consolidated business in which the taxpayer is also a part), was sold and was chartered back by the taxpayer (or another person comprising part of a consolidated business in which the taxpayer is also a part) all in a simultaneous transaction and the vessel or LNG transportation facility is on a term charter or lease to the taxpayer (or another person comprising part of a consolidated business in which the taxpayer is also a part) for a period of 15 years or longer.

(g) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel which are borne by the taxpayer for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the taxpayer for delivering it up at a specified location after the last voyage under that charter, or both if the taxpayer is obligated under the terms of the charter or contract of affreightment to bear them both.

(h) A reasonable rate of return under (b)(3)(D) or (b)(4)(B) of this section is presumed to be that amount which yields an internal rate of return (after federal income tax) on an investment which equals 2 percent plus the average annual national inflation rate (measured by the GNP deflator) during

(1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service, or

(2) if the period in (1) of this subsection falls entirely within a calendar year, that entire calendar year.

(i) At the request of a taxpayer or on its own motion, the department will, in its discretion, replace the return under (h) of this section with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(j) The third party nature of an agreement between a taxpayer and a third party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that taxpayer and carrier into a consolidated business, if, at the time they entered into that agreement, neither the taxpayer nor the carrier exercised, directly or indirectly, any control over the business affairs of the other as the result of, or in anticipation of, their subsequent consolidation into that same consolidated business.

(k) For purposes of this section, a "pipeline facility" includes all facilities incident to the pipeline transportation of oil or gas downstream from the point of production as defined in sec. 900 of this chapter. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.240. DEDUCTION FOR DIRECT OPERATING COSTS.
(a) The direct operating costs during a year that are incurred by or for a taxpayer for a lease or property in the state are a deduction in determining the taxpayer's taxable production income for that year.

(b) Before the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs for geological and geophysical work conducted on the lease or property after the taxpayer has acquired a working interest in the lease or property;

(2) the costs of drilling and/or operating wells bottomed on the lease or property; and

(3) the costs of operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the

operator, then the direct operating costs for that lease or property are the costs (excluding development costs but including drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(c) No cost for the taxpayer's general overhead or administrative expense and no cost that is to be amortized or depreciated under secs. 250-260 of this chapter may be included in this section.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.250. DEDUCTION FOR ACQUISITION COSTS. (a) A taxpayer's acquisition costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is commercial production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

(b) If a lease or property is abandoned, then the taxpayer's unamortized acquisition costs for that lease or property are a deduction in determining the taxpayer's taxable production income for the year in which the lease or property is abandoned. If only part of the lease or property is thus abandoned, the unamortized acquisition costs for that lease or property must be apportioned to that abandoned portion on the basis of acreage.

(c) A taxpayer's acquisition costs for a lease or property having commercial production from (or allocated to) it during a year must be amortized, and the amount of amortization that year for those acquisition costs is a deduction in determining the taxpayer's taxable production income for the year. Except for cases when (d) of this section applies, the amount of amortization in a year for a lease or property equals the taxpayer's unamortized acquisition costs as of the beginning of that year, multiplied by the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu-equivalents represented by the remaining proved reserved (both developed and undeveloped) of that lease or property as of the beginning of the year.

(d) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a production interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective amortization of acquisition costs for that portion of the year preceeding the transfer separately from its amortization of acquisition costs for that portion of the year following the transfer; and the sum of each taxpayer's respective amortization of acquisition costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating amortization for the portion of the year preceeding the date of the transfer, the taxpayer shall use the procedure prescribed in (c) of this section, except that the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceeding the date of the production-interest transfer. For that portion of the year following the transfer, the amount of amortization equals the taxpayer's unamortized acquisition costs as of the time immediately following the production-interest transfer, multiplied by the ratio of Btu-equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved reserves (both developed and undeveloped) of the lease or property as of the time immediately following the production-interest transfer.

(e) The amount of the taxpayer's unamortized acquisition costs for a lease or property as of the particular date equals the taxpayer's acquisition costs for its original production interest in the lease or property, plus the unamortized acquisition costs for each production interest in the lease or property transferred to the taxpayer on or before that date, and minus the sum of

(1) the unamortized acquisition costs for each production interest in the lease or property transferred from the taxpayer on or before that date;

(2) the cumulative amount (as of that date) of the taxpayer's acquisition costs for the lease or property that has been allowed under this section for amortization or abandonment; and

(3) the taxpayer's standardized prior-tax amortization for the lease or property under sec. 630 of this chapter.

(f) A taxpayer amortizing its acquisition costs for a lease or property for financial accounting purposes on a basis other than a variant of unit-of-production amortization may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for amortizing its acquisition costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the method prescribed in this section to amortize its acquisition costs for leases or properties in the state.

(g) The amount of a taxpayer's acquisition costs for a lease or property equals the taxpayer's net payments for

(1) cash bonus or comparable advance payment to acquire the lease or property;

(2) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property used on or for the lease or property after its acquisition and before the completion of the discovery well for the field that includes the lease or property and ad valorem and other taxes paid to one or more municipalities under AS 29.53 that were incurred for property or operations on or for the lease or property after its acquisition and before the completion of that discovery well;

(3) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property which is properly attributable to the

acquisition of the lease or property (as opposed to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property);

(4) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (3) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.260. DEDUCTION FOR DEVELOPMENT COSTS. (a) A taxpayer's development costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

(b) If a lease or property is abandoned without ever having had commercial production from (or allocated to) it, then the taxpayer's undepreciated development costs for that lease or property are a deduction in determining that taxpayer's taxable production income for the year in which the lease or property is abandoned.

(c) Except for development costs to which (e) or (f) of this section applies, a taxpayer's development costs for a lease or property having commercial production from (or allocated to) it during a year must be depreciated, and the amount of depreciation that year for those development costs is a deduction in determining the taxpayer's taxable production income for the year. The amount of depreciation in a year for a lease or property will be calculated by

(1) the unit of production method, which equals

(A) the average between the taxpayer's undepreciated development costs for the lease or property as of the beginning of the year and those costs as of the end of the year; multiplied by

(B) the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu-equivalents represented by the remaining proved developed reserves for that lease or property as of the beginning of the year; or

(2) the sum of the years method, which is computed by applying a changing fraction to the average original acquisition costs computed under this section as reduced by estimated salvage value. The denominator of this fraction always remains the same, and is the sum of the numbers (years) representing the successive 12-month periods in the entire estimated life of the property. The numerator is the number of 12-month periods (including that for which depreciation is being taken) remaining in the useful life of the acquisition costs; or

(3) the double declining balance method, which is calculated at a uniform rate, which cannot exceed 200 percent of the applicable straight line rate, and is applied each year to the adjusted basis of the average original acquisition costs computed under this section as reduced by depreciation previously taken but not reduced by salvage value; or

(4) the straight line method, which is computed by reducing the average original acquisition costs computed under this section, less estimated salvage value, by equal annual amounts over the estimated useful life of the property.

(d) The choice of the depreciation method specified in (c) of this section does not require a formal choice by the taxpayer. However, the choice must continue through a taxable year and is binding for that taxable year. The total amount of depreciation taken cannot exceed the original acquisition cost, less estimated salvage value. (As an illustration, suppose a $100 property with a 10-year life. The taxpayer might choose the double declining method for year one, choose the sum-of-the-years method for years two, three, four and five, and choose the straight-line method in year six. The total amount of depreciation would exceed $100 in year eight. Any depreciation claimed over $100 would be disallowed.)

(e) A taxpayer's undepreciated development costs for facilities or equipment for the lease or property which are removed during the year are excluded from the development costs that are to be depreciated that year under (c) and (d) of this section for that lease or property. Instead, the undepreciated development costs for those wells, facilities or equipment as of the beginning of the year, offset by their salvage value (if any), are a deduction in determining the taxpayer's taxable production income for the year in which they are removed.

(f) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a producing interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective depreciation of development costs for that portion of the year preceeding the transfer separately from its depreciation of development costs for that portion of the year following the transfer; and the sum of each taxpayer's respective depreciation of development costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating depreciation for the portion of the year preceeding the date of the transfer, the taxpayer shall use the procedure and choices prescribed in (c) and (d) of this section, except that if the unit of production method is used:

(1) the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceeding the date of the production-interest transfer, and

(2) for that portion of the year following the transfer, the amount of depreciation equals the average of the taxpayer's undepreciated development costs as of the time immediately following the production-interest transfer and as of the end of the year, multiplied by the ratio of Btu-equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved developed reserves of the lease or property as of the time immediately following the production-interest transfer.

(g) The amount of a taxpayer's undepreciated development costs for a lease or property as of a particular date equals the taxpayer's development costs as of that date for the wells, facilities and equipment for that lease or property that are then in place, minus the sum of

(1) the cumulative amount (as of that date) allowed under this chapter for depreciation of the taxpayer's development costs for the lease or property; and

(2) the taxpayer's standardized prior-tax depreciation for the lease or property under sec. 630 of this chapter.

(h) A taxpayer depreciating its development costs for a lease or property for financial accounting purposes on a basis other than a variant of the methods prescribed in (c) and (d) of this section may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for depreciating its development costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the methods prescribed in this section to depreciate its development costs for leases or properties in the state for purposes of this chapter.

(i) The amount of a taxpayer's development costs for a lease or property equals the taxpayer's net payments for

(1) development costs for facilities and equipment on or in support of the lease or property that directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property;

(2) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property and ad valorem and other tazes paid to one or more municipalities under AS 29.53 that were incurred directly as the result of, and in the course of, the installation or operation of the property described in (1) of this subsection;

(3) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property, which is properly attributable to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property (as opposed to the consideration given for the lease or property itself);

(4) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (3) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.320. EXTRAORDINARY OPERATING REVENUES AND LOSSES (OIL PIPELINES). (c) The costs of permanently terminating operations and/or removing part or all of the facilities and equipment of a pipeline result in extraordinary operating losses for that pipeline. The amount of these extraordinary operating losses which may be taken in any one taxable year, equals

(1) the portion of the unreimbursed, estimated termination and removal costs for that pipeline as may be allowed by FERC or other peremptory authority in a year prior to actual termination and removal according to specified factors and amounts used in calculating net carrier operating income; or

(2) the unreimbursed termination and removal costs for the pipeline that are actually incurred that year, offset by the salvage value (if any) of the removed facilities and equipment and offset to the extent of any amounts allowed to be taken prior to actual termination and removal under this section and taken by the taxpayer.

(d) If under (c) of this section, unreimbursed, estimated termination and removal costs for a pipeline are not actually expended or the deduction of those amounts is disallowed by FERC or other peremptory authorities, then the amount allowed or allowable as a deduction must be recaptured as extraordinary operating revenue.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.710. (f) A payment of less than $50,000 may be made by check in the manner prescribed in (1) of this paragraph or may be made by wire transfer in the manner prescribed in (2) of this paragraph. A payment of $50,000 or more must be made by wire transfer in the manner prescribed in (2) of this paragraph.

(1) A payment by check must be made by mailing the check, together with a copy of only the summary page (or pages) of the tax report, to the following address or other address as the commissioner may designate: Cashier, Department of Revenue, State of Alaska, Pouch SA, Juneau, Alaska 99811. A payment made by check or a return not requiring a payment will be considered timely if it is postmarked on or before the date or day of the month in which it is due.

(2) A payment by direct wire transfer must be made through the commercial banking system in accordance with the following procedures:

(A) As early as practicable and in no event later than 9:00 a.m. of the morning of the day when the wire transfer is to be made, the taxpayer shall notify the Alaska State Treasury by Telex (at Telex number 09045333) of the amount of the taxpayer's payment;

(B) the taxpayer shall obtain sufficient collected funds to cover the payment and shall instruct the commercial bank holding those funds to initiate the transfer of federal funds (in the amount of the payment) through the Federal Reserve wire tranfer system to the credit of the State of Alaska Investment Account at the following address:

Bank of America, NT & SA
San Francisco, California
Securities Department #3255
Acct: State of Alaska Investment Account;

(C) the taxpayer shall make the payment in one lump sum from one bank;

(D) a payment made by wire transfer will be considered timely if the taxpayer's commercial bank has initiated the transfer of federal funds through the Federal Reserve wire transfer system on or before the last banking day of the month in which the payment is due, or on or before the last banking day prior to the date due, if the date due is not a banking day.

(3) "payment" as used in this section, means the total amount due or estimated to be due by the taxpayer and arising under any provision of AS 43.21, including taxes, interest and penalty.

Authority: AS 43.05.080
AS 43 05.280
AS 43.21.070
AS 43.21.090

15 AAC 12.900. DEFINITIONS. (24) "point of production" means

(1) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; and in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or in the absence of a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose) through

which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(2) for gas, the meter on, or nearest (measured along the course taken by the gas) to, the lease or property from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless whether the particular gas in question is actually sold at that meter.

(31) "sales delivery point" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the contract or agreement for that sale, except in the case of a sale to which (f) of this section applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the sales price of the taxpayer's gas under (h)(3) of this section.

(33) "same market" means

(1) with respect to a taxpayer's oil refined in Alaska, the Alaskan market,

(2) with respect to a taxpayer's oil landed on the U.S. West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii),

(3) with respect to a taxpayer's oil landed on the U.S. Gulf Coast, the Gulf Coast market,

(4) with respect to a taxpayer's oil landed on the U.S. East Coast, the East Coast market,

(5) with respect to a taxpayer's oil landed in Puerto Rico or the U.S. Virgin Islands, the Puerto Rican and Virgin Island market,

(6) with respect to a taxpayer's gas marketed in Alaska, the Alaskan market or portion of it served by gas from the same field or area as the taxpayer's gas,

(7) with respect to a taxpayer's gas marketed in the Lower 48, the Lower 48 market,

(8) with respect to a taxpayer's gas marketed in a foreign country, the market in that foreign country.

(34) "taxpayer" means a corporation or, collectively, two or more corporations made subject to this chapter that are parts of the same consolidated business under this chapter.

(35) "tax year" means a period beginning on January 1 and ending on the following December 31st, except that for a fiscal-year taxpayer "tax year" means that taxpayer's fiscal year or, for the first fiscal year in which the taxpayer reports and pays tax on a fiscal year basis under this chapter, that portion of that fiscal year beginning on and following January 1.

(36) "voyage and port costs" is defined in sec. 132(e) of this chapter.

(37) "working interest" means any interest (including fee title) in the production of oil and gas that is not a royalty interest.

(38) "year" means tax year unless the context indicates otherwise. (Eff. / / , Reg.)

Authority: AS 43.05.080
AS 43.21.090

ELEVENTH LEGISLATURE

FISCAL NOTE

I. REQUEST

Bill/Resolution No. Senate Bill No. 474

Title An Act repealing Ch. 20 and amending Ch. 21 of Title 43, AK Statutes.

Requested by Senate State Affairs & Finance Committees Date 2/29/80

II. FISCAL DETAIL

Agency Affected Revenue

Program Category Affected Fiscal Services

BRU, Program, or Subprogram(s) Affected Audit Division

(Note: If more than one budget component is affected, separate line-item amounts and funding for each component in the analysis section.)

EXPENDITURES (Thousands of Dollars)

	FY 80	FY 81	FY 82	FY 83	FY 84	FY 85
100 PERSONAL SERVICES			(641.4)	(641.4)	(641.4)	(641.4)
200 TRAVEL			(85.0)	(85.0	(85.0)	(85.0)
300 CONTRACTUAL			(253.5)	(253.5)	(253.5)	(253.5)
400 COMMODITIES			(20.0)	(20.0)	(20.0)	(20.0)
500 EQUIPMENT						
600 LAND & STRUCTURES						
700 GRANTS, CLAIMS, ETC.						
TOTAL			(999.9)	(999.9)	(999.9)	(999.9)

FUNDING (Thousands of Dollars)

GENERAL FUND			(999.9)	(999.9)	(999.9)	(999.9)
FEDERAL FUNDS						
OTHER (Specify Fund Source)						

POSITIONS

FULL TIME			(22)	(22)	(22)	(22)
PART TIME						
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

See attached memorandum to R. D. Stevenson dated 2/29/80.

IV. DATE February 29, 1980 PREPARED BY [signature]

AGENCY Department of Revenue, Audit Division

PHONE 465-2320

Original: Legislative Finance

cc: Budget and Management

Prime Sponsor (First Legislator Named)

33-001 (Rev. 12/79)

Revenue Implications

* Sec. 1. No immediate revenue impact; this section avoids a constitutional issue dealing with taxation of OCS related activities.

* Sec. 2. [illegible]
[illegible]
for [illegible]
The [illegible]
[illegible]
$12 MM costs [illegible]
The [illegible]
$20 MM [illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]
[illegible]

Tosco

Date	High	Low	Close	Nov 35
4/11				1
4/10				
4/9				
4/8	20 5/8	19 3/4	20 1/4	1
4/7	20 1/8	19	19 3/4	
4/3	[illegible]	[illegible]	21 7/8	1 1/4
4/2	[illegible]	21 1/8	21 5/8	1 1/4
4/1	21 [illegible]	[illegible] 1/8	21	[illegible]
3/31	20 3/4	19 7/8	[illegible]	1 1/4
3/28	19 7/8	[illegible]	19	1 1/16
3/27	17 3/4	14 3/4	17 3/4	13/16
3/26	19 [illegible]	18 [illegible]	[illegible]	1
3/25	19 [illegible]	18 1/4	18 3/4	1
3/24	21 1/8	19 3/8	19 1/2	1 1/4
3/21	21 7/8	20 1/4	21	1 9/16
3/20	21 3/4	20 5/8	21 [illegible]	1 11/16
3/19	22	2[illegible]	21 3/8	1 11/16
3/18	[illegible]	19 5/8	21 [illegible]	1 [illegible]
3/17	22 1/4	20	[illegible]	1 1/8
3/16	22 3/4	21 [illegible]	[illegible]	2
3/13	2[illegible]	22 5/8	22 5/8	2 1/16
3/12	24	[illegible] 1/8	2[illegible] 7/8	[illegible]
3/11	[illegible]	[illegible]	23 7/8	[illegible]
3/10	[illegible]	[illegible]	23	1 [illegible]
3/7	25	23 7/8	23 1/8	2 1/2
3/6	[illegible]	[illegible]	24 1/8	2 [illegible]
3/5	[illegible]	26 [illegible]	26 3/8	3
3/4	27 [illegible]	[illegible]	27 1/4	[illegible]
[illegible]	[illegible]	[illegible]	27 1/4	[illegible]
			24	[illegible]

[illegible] [illegible] 4 [illegible] larger [illegible] the
[illegible] [illegible] & [illegible] [illegible] income,
Cost $5 million [illegible] [illegible]
Check [illegible] [illegible] one. There
are [illegible] [illegible] [illegible] [illegible]
and [illegible] [illegible] [illegible].

– The [illegible] [illegible] this year
[illegible] [illegible] [illegible] [illegible]

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

AUDIT DIVISION
POUCH W—ALASKA OFFICE BUILDING

FINANCE DIVISION
POUCH WF—STATE CAPITOL

JUNEAU, ALASKA 99811

October 3, 1979

M E M O R A N D U M

TO: The Honorable Russ Meekins
Chairman, House Finance Committee

FROM: Milt Barker, MB Fiscal Analyst
Legislative Finance Division

SUBJECT: Petroleum Corporate Income Tax Depreciation and the Surplus

The Department of Revenue is considering accelerating the allowances for depreciation that may be claimed on income tax returns of corporations engaged in petroleum production or transportation. Their interest in so doing stems from the large general fund surpluses now accruing as well as the suit filed by the oil companies against the petroleum income tax.

If such a policy is adopted and depending on how liberal the depreciation allowances are, the legislative finance estimates mentioned in my attached September 5 memo, of $4,328.9 million available for appropriation for FY 81, including $3,612.9 million in cash would have to be significantly reduced. Conceivably if the policy is liberal enough and made retroactive, all petroleum corporate income tax liability through FY 81 could be eliminated. This would mean FY 81 general funds available for appropriation would be $2,887.3 million of which $2,171.3 million would be cash based on the September 1979 Department of Revenue estimates (attached) as reduced for petroleum corporate income tax receipts and $50 million in interest that would be otherwise earned thereon.

Depreciation Methods

AS 43.21.020(c)(5) permits a deduction on the income tax returns for depreciation determined by "using the unit of production method or such other reasonable methods as the department may by regulation establish."

So far, the only method authorized by regulation is the unit of production method. This is an "accelerated" method in comparison with straight-line depreciation but is not as "accelerated" as two other methods, the double-declining balance and sum-of-the-years' digits methods, which are available under the federal IRS code and, by virtue of adoption of the federal code by the State, the regular State corporate income tax.

The Suit

The suit has prompted thoughts about accelerated depreciation for two reasons:

1. It might help the State's defense against the charge that the petroleum corporate income tax violates the "equal protection" clauses of the State and Federal constitutions since the previously mentioned depreciation methods are only available for corporate activities other than petroleum production and transportation. Of course, if the court found against the State on this basis, the accelerated depreciation could just as well be allowed after the decision.

2. In the event the State lost the suit or changes were mandated that reduced tax liabilities, the amount of refunds the State would have to pay to the oil companies would be reduced.

The magnitude of the possible refunds is unsettling and may help to explain why the Department of Revenue's latest revenue projections (September quarterly update) still project FY 80 receipts for the petroleum corporate income tax at $160 million even though receipts for the first quarter of FY 80 total $120.5 million.

Based on the Department of Revenue's estimates, a total of $552.6 million will be received through FY 81 for the petroleum corporate income tax. Using the same estimates inherent in the legislative finance figures in my September 5 memo, the receipts through FY 81 would be roughly $1.2 billion.

Is the administration really anxious about the outcome of the suit? If so, is accelerating depreciation to reduce the State's exposure to a large refund the best way to deal with this problem? Or would "sterilizing" these funds in some manner so that they aren't used for budget expenditures or illiquid investments preferable? Certainly the administration can do this through the veto power and their investment policies.

If the State wins the suit, the cost of the accelerated depreciation policy is the interest that could have been earned on the resulting tax reduction. However, in the event of a loss, the State owes interest at 8% on its refunds so accelerated depreciation then represents no cost to the State to the extent our average investment earnings are 8% and no more.

The Department of Revenue can probably allow double-declining balance and sum-of-the-years' digits by regulation to meet their concerns regarding the suit. If allowed retroactively, these methods might be sufficient to wipe out the tax liabilities incurred heretofore, resulting in immediate refunds.

Accelerated depreciation would probably then necessitate the carry-forward of losses. This has already been permitted by the Department of Revenue via regulation although there is no specific statutory authority for it in AS 43.21.

The Surplus and Oil Company Incentives

Is the administration confident about the suit but proposing accelerated depreciation mainly as a way to reduce the surplus, again in place of wielding the veto power? If so, judgement about the desirability of this policy and the weighing of its costs may occur in a different light.

If this is the objective, legislation could be proposed that sets up a capital recovery account as is being considered for net profits leasing, allowing maximum acceleration of depreciation. Expensing of capital costs with carry-forward of losses would amount to the same thing. Of course, the greater the acceleration, the greater the cost to the State in interest earnings foregone.

Accelerated depreciation only shifts the timing of tax liabilities into the future; it does not increase them in any way that would make up for the lost interest. Of course, on new leases the interest will be recovered in higher bids. There should be an actual gain to the state because the oil companies' discount rate should be higher than the state's earnings rate on invested funds.

An interest charge for the excess of accelerated depreciation over unit-of-production or straight-line could be incorporated into the tax statutes. If the interest charge were set at the state's earnings rate on invested funds, the state would be indifferent as to whether a company took accelerated depreciation or not. Yet, an oil company with a presumably higher earnings rate would be able to increase their net present value by using accelerated depreciation.

Thus, even if interest is charged, accelerated depreciation, while reducing the surplus, would provide a positive incentive for the development of marginal fields or secondary or tertiary recovery operations on developed fields. The state might even gain in the absence of an interest charge if the additional development produced revenues sufficient to more than offset the interest lost from accelerated depreciation on fields that are already developed or would be developed regardless.

An alternative way to recapture at a later time the lost interest on accelerated depreciation would be to graduate the corporate tax rate upwards from 9.4%. However, there could be no assurance of the increased tax liability even roughly matching the interest lost.

Joseph K. Donohue, Deputy Commissioner
Department of Revenue

October 29, 1979

Robert M. Johnson, Director
Petroleum Revenue Division

Impact of Allowing Intangible Drilling Expenses as a Direct Deduction

You have asked for an analysis of the financial impact of allowing intangible drilling costs (IDCs) as a deduction to derive taxable production income under the Oil and Gas Corporate Income Tax Act (AS 43.21).

As you know, drilling costs (intangible or tangible) incurred by oil and gas producers are not specifically allowed as an operating expense deduction in deriving taxable production income. Intangible drilling costs are, however, an allowable deduction under § 263 of the Internal Revenue Code. Prior to enactment of the Oil and Gas Corporate Income Tax (AS 43.21), § 263 was incorporated by reference into the Net Income Tax Act (AS 43.20) which applied to the oil and gas producers. That incorporation by reference disappeared with enactment of AS 43.21. The law does not now specifically address IDCs, but does permit as deductions to derive oil and gas produc ion income such items as dry hole expenses, interest expense not capitalized by the corporation up to a certain amount, and amortization of lease acquisitions. See, AS 43.21.020(b). Under the original regulations implementing that provision, "drilling costs" may be deducted to derive taxable production income only as a portion of acquisition and development costs. Those allowable costs are limited. 15 AAC 12.250 and 12.260. Operating expenses, which are generally deductible to the full extent of the expense incurred, exclude "drilling costs."

The Department is presently proposing to promulgate regulations which would allow IDCs, as a drilling cost, to be directly deducted as an operating expense.1/ Such a change in regulations would impose a significant impact on taxes received. Our preliminary calculation of taxes paid under AS 43.21 indicates that, as an example, the 1978 tax base of $1,780,402,000 would drop by $672,653,000 or 38%.2/ The taxes produced would consequently drop by a similar percentage or approximately $63,596,000. While the tax benefit to the covered taxpayers is a decrease in tax obligations of 38% industry wide, some taxpayers, depending on their unique circumstances, would stand to save over 100% of their tax obligations (resulting in a net operating loss) while others would see only minor savings. However, a weighted average among all taxpayers clearly places the [illegible] the tax savings at between 30 and 40%, as noted.

1/ Whether a regulation alone can permit this change is the subject of an opinion request to the Attorney General.

2/ Because of the nature of reporting taxes, the estimates of IDCs are based only on those reported under development cost deductions. 15 AAC 12.260. There also may be IDCs claimed under the present acquisition cost deductions (15 AAC 12.250) but these figures cannot be readily extracted. However, for purposes of calculating impact, the percentage figures, ratios and adjusted tax receipts would remain about the same as estimated or would show a slightly greater benefit for the taxpayer.

DISCUSSION OF THE OIL AND GAS INCOME TAX LAWSUIT

The Oil and Gas Income Tax Act, AS 43.21, taxes oil and gas companies at the same rate as other corporations. However, it provides for a different method of determining the tax base (i.e., taxable income) from the regular corporate income tax. AS 43.21 combines the two basic approaches to the taxation of income of multistate corporations. On one hand, it incorporates "separate accounting," in which the income and expenses of a company's in-state activities are separately determined without regard to the corporation's out-of-state business, as if the in-state business were the only business the company engages in. This approach is applied to determine an oil company's taxable income from oil and gas production or pipeline transportation. On the other hand, AS 43.21 also utilizes the "apportionment" approach, whereby income from the corporation's worldwide activities is apportioned to in-state activities by applying a formula. Apportionment is used in AS 43.21 to determine a taxpayer's in-state income from sources other than oil and gas production and pipeline transportation.

The litigation over AS 43.21 questions whether it violates the due process clause, the equal protection clause and the commerce clause of the U.S. Constitution, as well as provisions of the Outer Continental Shelf Lands Act that limit state taxation of the OCS. The original case, brought by Atlantic Richfield and Sohio, presents eight counts in its cause of action. The State subsequently presented the same eight counts, but expressed in the negative, in a second lawsuit against all other taxpayers under AS 43.21 who filed and paid under protest. The eight counts are:

1. <u>Duplicative taxation</u>. Count I of the Arco suit alleges that AS 43.21 results in impermissible duplicative taxation by imposing an unapportioned tax on interstate income. In other words, it alleges that separate accounting for production income and pipeline income is unconstitutional. The plaintiffs point out that other states which use an apportionment formula might require the plaintiffs to include the Alaska-taxed income as part of the total apportionable income for purposes of those other states' income taxes. The combined result, the companies argue, could be that more than 100% of their income ends up being taxed by the states.

A case is currently pending before the U.S. Supreme Court, <u>Exxon Corp. v. Wisconsin Dept. of Revenue</u>, which may considerably affect the outcome of Count I in the Arco case. The issue there is whether separate accounting is constitutionally required instead of apportionment in cases where a corporation has functionally separate operations (i.e., exploration, production and marketing) and some occur within the taxing jurisdiction and others are entirely outside it. If the Court requires separate accounting in Exxon, the State's position on Count I will be strengthened. If the Court upholds apportionment, then Exxon could seriously weaken our position, but not necessarily so; the exact effect would depend on the Court's reasoning and the language used in reaching its decision. The case is expected to be decided by the end of June.

Besides the basic question in Count I as to whether separate accounting is permissible in AS 43.21, there are also some issues of duplicative taxation in the application of the apportionment formula embodied in AS 43.21.040 for "other" income. For instance, although production and pipeline income earned in Alaska is already fully recognized under the separate accounting provisions, the income from similar activities occurring wholly outside Alaska is nevertheless included in the worldwide "pie" of income to be divided under apportionment. Similarly, a company engaged only in production in Alaska could still be subjected to apportionment of its "other" worldwide income simply because it charters tankers from a third party to ship its oil out of the state. Both of these problems would be dealt with in the Administration's "technical amendments" bill (HB 963), at a cost to the State of less than a million dollars in FY 81.

While these last two issues have relatively small dollars-and-cents consequences themselves, losing them in court could be serious. The legislative history of AS 43.21 shows that all antecedent versions of the bill in 1978 had severability clauses. The final version of AS 43.21 did not. One could argue from this fact that the Legislature wanted the entire Act to stand or fall together. If the courts agreed, then losing even these "minor" issues would lead to the downfall of the entire tax. The possibility of this outcome is, of course, significantly reduced by the general severability clause in AS 01.10.030, but not absolutely eliminated.

2. Equal protection. The second count in the Arco case alleges that AS 43.21 discriminates against interstate commerce and violates equal protection and due process. This is based on a comparison of the tax treatment of oil and gas companies under AS 43.21 vis-a-vis their previous treatment under AS 43.20, which is still afforded to all other corporations. This issue could not be entirely resolved, legislatively or by regulation, except by repealing AS 43.21 and going back to AS 43.20 as the tax for the oil industry. However, there are legislative and regulatory actions that could be taken that would eliminate differences between AS 43.20 and AS 43.21 that the industry regards as being the

most important. These relate to accelerated depreciation and the expensing of intangible drilling costs for wells in Alaska.

Depreciation is currently allowed for production equipment on a unit-of-production basis; that is, each barrel produced has the same amount of depreciation associated with it. This is a form of accelerated depreciation since production rates over the life of a field are greatest in the early years and fall off in later years. By regulation the Department of Revenue could authorize other forms of accelerated depreciation, such as those used for the IRS.

Depreciation for pipelines is strictly on a straight-line basis. This is because taxable pipeline income is tied by statute to the pipeline's net income as regulated by the Federal Energy Regulatory Commission (FERC). FERC uses straight-line depreciation.

Allowing accelerated depreciation does not affect the total amount of depreciation allowed as a deduction, it changes the timing. The effect is to reduce the tax liability in the early years and make up for it in later years. In the case of tax year 1980 (one quarter paid in FY80 and three quarters in FY81), the tax deferral from accelerated depreciation of production equipment would be $25 million. For pipelines it would be $36 million.

Intangible drilling costs are now required to be capitalized and depreciated on a unit-of-production basis as production equipment. Expensing such costs is the fastest possible form of accelerated depreciation. If only new drilling could be expensed, the tax deferral would be about $72 million for FY81.

3. Excessive, discriminatory taxation. In Count III of the complaint, plaintiffs alleged that the amount of taxes imposed by AS 43.21 bears no fair relation to services provided by the State. In doing so, they pointed out the large anticipated surplus of funds coming into the treasury, the high proportion of state revenues already being derived from sources other than AS 43.21, and the large amount of taxes that they will have to pay in addition under the oil and gas income tax.

4. Modification of leases. Count IV of the complaint alleges that Alaska, by enacting AS 43.21, unilaterally and unconstitutionally modified its oil and gas leases. This seems almost frivolous in light of the Alaska Constitution's specific prohibition against contracting away the State's taxation power; no lease provision could have abridged this power.

5. OCS income. The Outer Continental Shelf Lands Act forbids the states from taxing activites beyond their three-mile limits. Count V of the Arco/Sohio complaint alleges that AS 43.21.040, by including Alaska OCS property and payrolls in the formula for apportioning worldwide "other" income, violates this federal prohibition and is thus pre-empted under the supremacy clause of the U.S. Constitution. The dollars at stake in Count V are comparatively small at present, under $5 million a year. But this would change if there is significant new activity in the OCS off Alaska. Also, an adverse ruling here could bear on the nonseverability issue.

6. Retroactivity. Count VI of the lawsuit raises a technical question as to procedure in the enactment of AS 43.21. Plaintiffs allege that the Act, which became law on July 6, 1978, cannot be made retroactive to the first of that year without the concurrence of two-thirds of the membership of each house of the Legislature. They further allege that such concurrence was not given by the Senate. This issue should, at most, affect receipts under AS 43.21 for only part of the 1978 tax year.

7. Regulations. The Department adopted regulations requiring payments of estimated taxes in installments in advance of the final due date for each year. Count VII alleges that the statutory authorization for "installments" means the Department could only adopt regulations allowing payments after the due date. The effect of losing this count would not be a loss in tax receipts finally collected, but only in the cash-flow timing of those receipts and the lost interest income from the prepayments. The lost interest would be $45.8 million a year if the annual tax receipts are $500 million.

8. Taxation of out-of-state income. Count VIII alleges that AS 43.21 taxes out-of-state income having no connection with Alaska. To some extent this repeats the Count I challenge to aspects of the apportionment formula. Besides being a sort of "catch all," this last count could also refer to AS 43.21.010, which subjects to the tax all corporations deriving income from the production of oil and gas from a lease or property "in or directly associated with the state". The underlined portion refers to leases in the OCS whose operations are supported from a base or staging area onshore in Alaska. There is a real constitutional "due process" question as to whether Alaska may tax a corporation having no contact with Alaska other than deriving income from a lease or property "directly associated" with the state. In addition, the provisions of the OCS Lands Act could apply to bar such taxation. HB 963 would eliminate this issue. Since there are at present no such corporations, the present revenue effect is nil. Again, a loss here could trigger far greater effects if nonseverability in fact applies to the Act.

SETTLEMENT DISCUSSIONS IN THE OIL AND GAS INCOME TAX LAWSUIT

In the course of administering AS 43.21, the Department of Revenue has had to adopt a considerable number (over 30 pages worth in the Administrative Code) of fairly technical, detailed regulations to clarify and interpret the Act. In order to adopt appropriate and workable regulations covering such complex and arcane matters as the leveraged leasing of oil tankers, there was considerable dialogue and discussion, both at hearings and in conferences, between the Department and various affected oil companies.

As the full range of policy considerations relating to the successful implementation of the tax was discussed, certain regulatory actions appeared which, in conjunction with some legislative amendments, presented a good promise of being a foundation for a settlement by which the basic validity of the tax would be acknowledged, while reserving for litigation a few narrow issues about the particulars of the application of the tax. The ongoing litigation of those issues would therefore not jeopardize the tax itself, nor would their adjudication one way or the other put major sums of money at risk.

These legislative and regulatory actions do not fall neatly into the categories of issues presented in the various counts given by Arco and Sohio in their lawsuit. In fact, a number of the actions do not even tie directly into any one count. In some cases, the proposed changes could be justified just on the basis of policy considerations, apart from any settlement possibilities. In this group of independently justifiable actions are:

1. The technical amendments proposed in HB 963. Reasons for them are given in Governor Hammond's transmittal letter. Their combined revenue effects are about $5 million a year.

2. Allow current amortization of estimated costs of terminating production operations, removing field facilities and restoring the site. There would be a "settling up" when these had happened to account for any over- or under-amortization. Reasons for this ar : A) termination costs may be carried back only three years, which may not allow for them to be fully recognized; and B) this is already allowed in the case of pipelines, because of current FERC rulings. The revenue impact would be about $2 million a year currently.

Less clearly justifiable would be the elimination of the present limitations on interest expense and overhead costs that may be deducted against production income. It would be advisable in such a case to grant the Department clear authority to set aside undue charges for these items, especially if they result from intracorporate or less-than-arms-length transactions. With such safeguards, the present revenue effect would be about $3,500,000 a year.

The big dollars-and-cents issue in the settlement discussion was accelerated depreciation. This is really a tax deferral since the total amount of depreciation ultimately taken does not change, regardless of whether the depreciation is straight-line or accelerated. For tax year 1980, it would amount to $61 million -- $25 million for production equipment and $35 million for pipelines. Of course, interest would be lost on the money until it is recovered, and the payback in later years would be in dollars of reduced buying power.

Intangible drilling costs are merely an aspect of accelerated depreciation. Right now they are capitalized and depreciated on the same basis as production equipment. Allowing them to be expensed (i.e., fully deducted as they are incurred) is simply allowing the ultimate in accelerated depreciation. As with pipelines and production equipment, the tax loss now would be recovered eventually through reduced deductions later in the life of the field. But the impact today is still some $72 million for FY81, not counting forgone interest.

The discussions of these possibilities indicated that, in exchange for these considerations, the oil companies would dismiss the present lawsuit except for the issues regarding OCS and the use of "book" income for apportionment instead of taxable income as reported to IRS. The settlement would not extend to any future developments in federal law, either judicial or legislative, that would impair or annul the State's method of taxing income. Also they would reserve the right to challenge new regulations or interpretations as may arise which are not subjects of the present litigation.

THE ROLE OF THE WINDFALL PROFITS TAX
IN THE OIL AND GAS INCOME TAX

The windfall profits tax is not recognized under AS 43.21 as an allowable deduction against production income. At present this has not become an additional basis for the oil companies' challenge to the oil and gas income tax, but it surely will be.

In thinking about the windfall profits tax, it is important to remember that it is not necessary to settle the lawsuit in order to deal with the windfall profits tax. It is separable from the settlement considerations. However, settlement is most unlikely if there is nothing done about the windfall profits tax.

The revenue implications of the windfall profits tax are far greater than the combined effects of all the other items involved in coming up with a settlement. In FY81 alone, the effect is $142.5 million; in FY82, another $378.4 million. By FY85 it will be almost $600 million a year.

In all settlement discussions through January of this year (when they were broken off), the windfall profits tax was recognized as a major factor for any settlement, but it was a subject whose discussion was postponed until Congress actually passed such a tax and we could see exactly what it was.

NOTICE OF PROPOSED CHANGES IN THE REGULATIONS (AS 43.21)
OF THE DEPARTMENT OF REVENUE

Notice is hereby given that the Department of Revenue, under authority vested by AS 43.05.080 and AS 43.21.090, propose to adopt regulations in Title 15 of the Alaska Administrative Code to implement the Oil and Gas Corporate Income Tax Act including AS 43.21.020, AS 43.21.040 and AS 43.21.070:

Title 15, Chapter 12 of the Alaska Administrative Code is amended by revising certain existing sections. The proposed regulations would amend:

Sec. 120 to specify when and how sales price and prevailing value are to be used in calculating value at point of production;

Sec. 130 to specify when and how actual costs and fair market value are to be used in calculating reasonable costs of transportation, and to redefine "effective ownership" of tankers;

Secs. 200, 220 and 230 to specify when cash basis accounting must be used;

[Secs. 240, 250 and 260 to provide for the direct deduction of drilling costs as direct operating costs;]

Sec. 320 to reflect FERC rulings on termination and restoration costs;

Sec. 510 to clarify income taxes included in net income for apportionment purposes;

Sec. 710 to provide new wire transfer and mailing rules.

Notice is also given that any interested person may present oral or written statements to the action proposed at the hearing of this matter scheduled for November 29, 1979 at 1:30 p.m. in the Anchorage Assembly Chambers, 3500 East Tudor Road, Anchorage, Alaska. Copies of a draft of the proposed regulations may be obtained by writing to Robert M. Johnson, Director, Petroleum Revenue Division, 201 East 9th Avenue, Suite 304, Anchorage, Alaska 99501.

The Department of Revenue, upon its own motion or at the instance of any interested person, may at the hearing or after it adopt the proposals substantially as have been described without further notice or may decide to take no action on them.

DATE: 10/29/79

THOMAS K. WILLIAMS
COMMISSIONER

by [signature]
Robert M. Johnson
Director
Petroleum Revenue Division

15 AAC 12.120 VALUE AT THE POINT OF PRODUCTION. (a) The value at the point of production for oil or gas produced from a lease or property is the sales price or prevailing value of that oil or gas, minus the reasonable cost of transportation (if any) from the point of production for that oil or gas to the sales delivery point for that oil or gas; except that in no event may the value at the point of production for a taxpayer's oil or gas exceed the ceiling price (if any) that is applicable to that oil or gas under a mandatory price control program.

(1) For purposes of this chapter, the sales price of oil or gas shall be used to determine value at point of production except when (2) of this subsection applies, in which case prevailing value shall be used to determine value at the point of production;

(2) Prevailing value must be used in those instances when the oil or gas is sold or exchanged under circumstances where the sales price is substantially lower than the prevailing value for oil or gas of like kind, character and quality being sold at sales delivery points in the same market or in a comparable market if there are no such sales of significant quantities in the same market; provided that

(A) "circumstances" as used in this subsection refers to instances where terms of a contract set a single price for oil or gas without adjustments tied to market conditions for periods of longer than 6 years or where the terms of a contract set prices bearing no relation to market conditions prevailing at the time the contract is entered or where fraud or an intent to evade taxes is demonstrated; and

(B) the determination of a "substantially lower" price under this subsection is to be made by analyzing the cash value of consideration received for oil or gas and taking into account any asserted difference between sales price and prevailing values, the quantity of oil or gas involved in the transaction, and the duration of the contract giving rise to the claim.

(b) "Sales price" under this chapter is:

(1) for the first bona fide, arm's-length sales to a third party, the cash value of the full consideration given in receipt for the taxpayer's oil or gas so sold; and

(2) for all other transactions, the greater of

(A) the cash value of the full consideration given in receipt for the taxpayer's oil or gas used, exchanged, or otherwise transferred to another party; or

(B) the sales price attributable to that transaction entered on a taxpayer's books in accordance with generally accepted accounting principles, consistently applied.

(c) "Prevailing value" under this chapter for oil is the arithmetic average of the total acquisition cost for the four reference crude oils delivered CIF at the gate of the refinery to which the taxpayer's oil is ultimately delivered. The four reference crude oils are Iranian Heavy, Arabian Light, Arabian Medium, and Mexican Isthmus, and the total acquisition cost of each of them is the sum of

(1) the state sales price for the reference crude oil with adjustments for differentials and surcharges appearing in the latest Platt's Oilgram Price listing published on or before the date of delivery of the taxpayer's oil at the sales delivery point; and

(2) the transportation charges for the reference crude oil from its point of shipment to the gate of the refinery to which the taxpayer's oil is ultimately delivered as computed by multiplying the London Tanker Brokers' average freight rate assessment ("AFRA") applicable to the date of delivery of the taxpayer's oil at the sales delivery point for AFRA II vessels (long-range II oil tankers) by the most recently published Worldscale rate for the voyage, plus any canal tolls and expenses not included in the AFRA.

(d) Prevailing value for gas is

(1) the volume-weighted average of the prices received by the taxpayer in arm's-length sales transactions which have been entered into or whose pricing provisions have been amended during the tax year or the two preceding years for significant quantities at the sales delivery points within the same market for that production for Alaskan gas of like kind, character and quality produced during the month; or

(2) if the taxpayer makes no arm's-length sales of significant quantities at the sales delivery points within the same market for Alaskan gas of like kind, character and quality produced during the month, the volume-weighted average of the prices being given and received under the terms of arm's-length sales contracts (whether between third parties or not) which have been entered into or whose pricing provisions have been amended during the tax year or the two preceeding years for significant quantities of gas from the same field as the taxpayer's gas (or if there are no such contracts for that field, the counterparts of those contracts in the nearest field to that field), with appropriate adjustments for differences (if any) in kind, character and quality between gas sold under the reference sales contracts and the taxpayer's gas.

(3) for purposes of this subsection, "same market" means

(A) a market in Alaska;

(B) a market in other states, provinces, or territories of the United States or Canada; or

(C) any other market (e.g. Asia).

(e) For purposes of this chapter, "sales delivery point" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the contract or agreement for that sale, except in the case of a sale to which (h) of this section applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's-length sale to a third party, the gate of the refinery to which that oil is ultimately transported; and

(3) for a taxpayer's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the sales price of the taxpayer's gas under (d)(3) o this section.

(f) For purposes of this chapter, "point of production" means

(1) for oil, the automatic custody transfer meter of unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier, and in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or in the absence of a tank gauge, another mechanism or device to measure the quantit of oil that has been approved by the department for this purpose) through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(2) for gas, the meter on, or nearest (measured along the course taken by the gas) to, the lease or property from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless of whether particular gas in question is actually sold at that meter.

(g) Notwithstanding anything to the contrary in (a) - (f) of this section, where a taxpayer's gas from a lease or property is run through a gas processing plant and part or all of the residue gas and extracted liquids are returned to that taxpayer, the "value at the point of production" for that gas is the total value of that residue gas and extracted liquids they come out of the plant, less (1) a reasonable allowance (either withheld in kind by the plant operator or paid in cash to the plant operator) for the cost of processing that gas through the plant, (2) the reasonable cost of transportation, if any, from the point of production for that gas to the intake into the plant, and (3) the value of any residue gas returned to the taxpayer that is used, flared or unavoidably lost in the production operations for the lease or property or is injected into a reservoir in the course of operations for the same field.

(h) If a taxpayer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the taxpayer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the taxpayer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the taxpayer were the shipper for purposes of § 130 of this chapter. This subsection does not apply if the taxpayer's expected repurchase does not in fact occur.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090
AS 43.21.120

15 AAC 12.130 REASONABLE COSTS OF TRANSPORTATION. (a) Reasonable costs of transportation are to be calculated from the point of production to the sales delivery point.

(b) Except as provided in (c) of this section, the reasonable cost of transportation is the actual cost of transportation.

(c) The reasonable cost of transportation is the fair market value when all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

(d) "Actual costs" of transportation for purposes of this section are:

(1) when the transportation of oil or gas is by a regulated carrier, the tariff on file with FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) when transportation of oil is by a tanker or other vessel that is not owned or effectively owned by the taxpayer

(A) for a single voyage charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the taxpayer plus the positioning cost, if any, borne by the taxpayer for that vessel;

(B) for a consecutive voyage charter or a time charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the taxpayer, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter), if any, borne by the taxpayer for that vessel; or

(C) for a contract of affreightment, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee which are incurred with respect to that transportation during the term of the contract of affreightment and which are borne by the taxpayer.

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by the taxpayer, the taxpayer's actual cost for that transportation which is the sum of:

(A) the voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(C) depreciation of the vessel; if the vessel is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this subsection, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this subsection,

(i) "acquisition costs" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, but not including costs of improvements made after the date the vessel is placed in service by or on behalf of the taxpayer; and

(ii) "expected life" means the period of time used to calculate depreciation under (C) of this subsection.

(4) in the case of transportation of gas as LNG,

(A) where not all of the LNG transportation facilities are subject to tariff regulations (by FERC or other agencies of the United States, state or territory or a possession of the United States or a foreign nation) and when the taxpayer does not have or effectively have any ownership interest in the LNG transportation facility, the amount charged to the taxpayer for that LNG transportation;

(B) when the taxpayer has or effectively has an ownership interest in the LNG transportation facility, the taxpayer's actual cost for that transportation equalling the sum of:

(i) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the taxpayer's gas;

(ii) depreciation of the LNG transportation facility; if the facility is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iii) an amount which, when added to the amount of depreciation allowed under (ii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, and "expected life" means the period of time used to calculate depreciation under (ii) of this subparagraph.

(e) "Fair market value" of transportation for purposes of this section is to be determined:

(1) for shipments of oil, on the basis of third party charters (that is, time charters in which the taxpayer does not own or effectively own the vessel) of one year or more, plus regulated transportation costs determined under (d)(1) of this section. Two vessels will be considered like vessels for purposes of comparing like transportation under this chapter if the difference between them in dead-weight tonnage is less than 10,000 dead-weight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels; or

(2) for shipments of gas as LNG, on the basis of third party charters or leases (that is, charters or leases in which the taxpayer does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the Department for like LNG transportation facilities, plus regulated transportation costs determined under (d)(1) of this section.

(f) If a taxpayer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the taxpayer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the taxpayer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the taxpayer were the shipper. This subsection does not apply if the taxpayer's expected repurchase does not in fact occur.

(g) For purposes of this chapter, "voyage and port costs" for a vessel are

(1) costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and for her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid, minor cargo losses or measuring

differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be prorated equally among vessels) for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the shipper, and other reasonable costs associated with the operation or maintenance (or both) of the vessel, and

(2) in addition to the costs listed in (1) of this subsection, in the case of catastrophic loss or damage of a vessel transporting oil or LNG from Alaska or enroute to Alaska to take on oil or LNG, a portion of the loss (for loss or damage of the ship, for injury or less of her captain or crew and for damage and clean-up due to spillage of part or all of her cargo, but not for the loss of the cargo itself) which is borne by the shipper as the result of that catastrophic loss or damage and which is not reimbursed by insurance or by a third party; this portion of the loss is determined by dividing the unreimbursed liability on the basis of dead-weight tonnage among the vessels owned, effectively owned or chartered by the shipper to transport oil or LNG (whichever was lost) from Alaska.

(h) A taxpayer "effectively owns", has "effective ownership" or "effectively has an ownership interest" in a vessel or LNG transportation facility for purposes of this section, if:

(1) the vessel or LNG transportation facility is owned by another person comprising part of a consolidated business in which the taxpayer is also a part; or

(2) the vessel or LNG transportation facility is the subject of a capital lease in which the taxpayer or another person comprising part of a consolidated business in which the taxpayer is also a part, is the lessee; or

(3) the vessel or LNG transportation facility was built to the account of the taxpayer (or another person comprising part of the consolidated business in which the taxpayer is also a part), was sold and was chartered back by the taxpayer (or another person comprising part of the consolidated business in which the taxpayer is also a part) all in a simultaneous transaction and the vessel or LNG transportation facility is on a term charter or lease to the taxpayer (or another person comprising part of the consolidated business in which the taxpayer is also a part) for a period of 15 years or longer.

(i) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel which are borne by the shipper for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the shipper for delivering it up at a specified location after the last voyage under that charter, or both if the shipper is obligated under the terms of the charter or contract of affreightment to bear them both.

(j) A reasonable rate of return under (d)(3)(D) or (d)(4)(B) of this section is presumed to be that internal rate of return (after federal income tax) on an investment which equals 2 percent plus the average annual national inflation rate (measured by the GNP deflator) during (1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service, or (2) if the period in (1) of the subsection falls entirely within a calendar year, that entire calendar year. At the request of a taxpayer or on its own motion, the department may replace this presumed rate of return with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(k) The third party nature of an agreement between a shipper and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that shipper and carrier into a consolidated business, if, at the time they entered that agreement neither the shipper nor the carrier exercised, directly or indirectly, any control over the business affairs of the other as the result of, or in anticipation of, their subsequent consolidation into the same consolidated business.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.200 DEDUCTIONS FROM GROSS PRODUCTION REVENUE--IN GENERAL.
(a) Unless otherwise specified, a taxpayer's costs giving rise to a deduction under §§ 210-290 of this chapter are regarded as being incurred on a cash basis or on an accrual basis, depending on which basis is used for purposes of the taxpayer's financial accounting. "Actually paid" or "actual payment" as used in §§ 210-290 shall refer to costs which must be incurred on a cash basis.

(b) Costs previously claimed and actually deducted on one or more of a taxpayer's returns filed under AS 43.20 and ch. 5 of this title must be excluded from the costs to be used in calculating a deduction under §§ 210-290 of this chapter.

(c) When a taxpayer incurs costs giving rise to a deduction under §§ 210-290 of this chapter and part or all of those costs are reimbursable to the taxpayer from one or more third parties, only the unreimbursed portion of those costs of the taxpayer may be used in calculating that deduction.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.220 DEDUCTION FOR PRODUCTION TAXES. Taxes imposed under AS 43.55 and AS 43.57 for production from (or allocated to) a lease or property which are actually paid by, or on behalf of, a taxpayer during a year constitute a deduction in determining the taxpayer's taxable production income for that year. The amount of tax paid under AS 43.55 includes EDIC applied under AS 43.55.018 against that tax.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.230 DEDUCTION FOR AD VALOREM TAXES. The amount of tax under AS 43.56 actually paid during a year to the state (net of credits or refunds made that year for municipal ad valorem taxes on the same properties) and the total amount actually paid that year for municipal and ad valorem taxes under AS 29.53.045-.055, for a taxpayer's properties used directly in the production, gathering, treatment or preparation for pipeline shipment of oil and gas from a lease or property that is in commercial production before those actual payments to the state or municipality are made, constitute a deduction in determining the taxpayer's taxable production income for that year.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.240 DEDUCTION FOR DIRECT OPERATING COSTS. (a) The direct operating costs during a year that are incurred by or for a taxpayer for a lease or property in the state are a deduction in determining the taxpayer's taxable production income for that year.

(b) Before the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs for geological and geophysical work conducted on the lease or property after the taxpayer has acquired a working interest in the lease or property;

(2) rentals and shut-in royalties paid in order to retain the lease or property;

(3) drilling costs for wells bottomed on the lease or property; and

(4) the costs for operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property, but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at lease one working-interest owner is a third party to the operator, the direct operating costs for that lease or property and the costs (excluding development costs but including drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(c) After the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs of operating the facilities and equipment on or for the lease or property which directly result in or are necessary for the continued or enhanced production from (or allocated to) the lease or property;

(2) the costs of drilling and/or operating wells bottomed on the lease or property; and

(3) the costs of operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at lease one working-interest owner is a third party to the operator, then the

direct operating costs for that lease or property are the costs (excluding development costs but including drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(d) No cost for the taxpayer's general overhead or administrative expense and no cost that is to be amortized or depreciated under SS 250-260 of this chapter may be included in this section.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.250 DEDUCTION FOR ACQUISITION COSTS. (a) A taxpayer's acquisition costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is commercial production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

Expense bonus on non-prod

(b) If a lease or property is abandoned, then the taxpayer's unamortized acquisition costs for that lease or property are a deduction in determining the taxpayer's taxable production income for the year in which the lease or property is abandoned. If only part of the lease or property is thus abandoned, the unamortized acquisition costs for that lease or property must be apportioned to that abandoned portion on the basis of acreage.

(c) A taxpayer's acquisition costs for a lease or property having commercial production from (or allocated to) it during a year must be amortized, and the amount of amortization that year for those acquisition costs is a deduction in determining the taxpayer's taxable production income for the year. Except for cases when (d) of this section applies, the amount of amortization in a year for a lease or property equals the taxpayer's unamortized acquisition costs as of the beginning of that year, multiplied by the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu-equivalents represented by the remaining proved reserves (both developed and undeveloped) of that lease or property as of the beginning of the year.

(d) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a production interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective amortization of acquisition costs for that portion of the year preceeding the transfer separately from its amortization of acquisition costs for that portion of the year following the transfer; and the sum of each taxpayer's respective amortization of acquisition costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating amortization for the portion of the year preceeding the date of the transfer, the taxpayer shall use the procedure prescribed in (c) of this section, except that the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceeding the date of the production-interest transfer. For that portion of the year following the transfer, the amount of amortization equals the taxpayer's unamortized acquisition costs as of the time immediately following the production-interest transfer, multiplied by the ratio of Btu-equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved reserves (both developed and undeveloped) of the lease or property as of the time immediately following the production-interest transfer.

(e) The amount of the taxpayer's unamortized acquisition costs for a lease or property as of a particular date equals the taxpayer's acquisition costs for its original production interest in the lease or property, plus the unamortized acquisition costs for each production interest in the lease or property transferred to the taxpayer on or before that date, and minus the sum of

(1) the unamortized acquisition costs for each production interest in the lease or property transferred from the taxpayer on or before that date;

(2) the cumulative amount (as of that date) of the taxpayer's acquisition costs for the lease or property that has been allowed under this section for amortization or abandonment; and

(3) the taxpayer's standardized prior-tax amortization for the lease or property under § 630 of this chapter.

(f) A taxpayer amortizing its acquisition costs for a lease or property for financial accounting purposes on a basis other than a variant of unit-of-production amortization may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for amortizing its acquisition costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the method prescribed in this section to amortize its acquisition costs for leases or properties in the state.

(g) The amount of a taxpayer's acquisition costs for a lease or property equals the taxpayer's net payments for

(1) cash bonus or comparable advance payment to acquire the lease or property;

(2) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property used on or for the lease or property after its acquisition and before the completion of the discovery well for the field that includes the lease or property and ad valorem and other taxes paid to one or more municipalities under AS 29.53 that were incurred for property or operations on or for the lease or property after its acquisition and before the completion of that discovery well;

(3) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property which is properly attributable to the acquisition of the lease or property (as opposed to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property);

(4) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (3) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.260 DEDUCTION FOR DEVELOPMENT COSTS. (a) A taxpayer's development costs for a lease or property in the state that has never had commercial production from (or allocated to) it from any zone are deferred for purposes of this chapter until either there is production from (or allocated to) it or until the lease or property is abandoned without ever having had commercial production from (or allocated to) it.

(b) If a lease or property is abandoned without ever having had commercial production from (or allocated to) it, then the taxpayer's undepreciated development costs for that lease or property are a deduction in determining that taxpayer's taxable production income for the year in which the lease or property is abandoned.

(c) Except for development costs to which (d) or (e) of this section applies, a taxpayer's development costs for a lease or property having commercial production (or allocated to) it during a year must be depreciated, and the amount of depreciation that year for those development costs is a deduction in determining the taxpayer's taxable production income for the year. The amount of depreciation in a year for a lease or property equals

(1) the average between the taxpayer's undepreciated development costs for the lease or property as of the beginning of the year and those costs as of the end of the year; multiplied by

(2) the ratio of the Btu-equivalents of the production from (or allocated to) that lease or property during the year, to the total number of the Btu-equivalents represented by the remaining proved developed reserves for that lease or property as of the beginning of that year.

(d) A taxpayer's undepreciated development costs for facilities or equipment for the lease or property which are removed during the year are excluded from the development costs that are to be depreciated that year under (c) of this section for that lease or property. Instead, the undepreciated development costs in those wells, facilities or equipment as of the beginning of the year, offset by their salvage value (if any), are a deduction in determining the taxpayer's taxable production income for the year in which they are removed.

(e) During a year it may happen that a taxpayer transfers part or all of its production interest in a commercially producing lease or property to one or more third parties or receives part or all of a producing interest in a lease or property as the result of a transfer from one or more third parties. In such a case, the taxpayer receiving the production interest and the taxpayer transferring the production interest shall each calculate its respective depreciation of development costs for that portion of the year preceeding the transfer separately from its depreciation of development costs for that portion of the year following the transfer; and the sum of each taxpayer's respective depreciation of development costs for those two portions of the year will be a deduction in determining that taxpayer's taxable production income for that year. In calculating depreciation for the portion of the year preceeding the date of the transfer, the taxpayer shall use the procedure prescribed in (c) of this section, except that the ratio of the Btu-equivalents of production may include only the taxpayer's production from (or allocated to) the lease or property for the portion of the year preceeding the date of the production-interest transfer. For that portion of the year following the transfer, the amount of depreciation equals the average of the taxpayer's undepreciated development costs as of the time immediately following the production-interest transfer and as of the end of the year, multiplied by the ratio of Btu-equivalents of the taxpayer's production from (or allocated to) the lease or property for the portion of the year on and after the date of the transfer to the total number of Btu-equivalents represented by the taxpayer's remaining proved developed reserves of the lease or property as of the time immediately following the production-interest transfer.

(f) The amount of a taxpayer's undepreciated development costs for a lease or property as of a particular date equals the taxpayer's development costs as of that date for the wells, facilities and equipment or that lease or property that are then in place, minus the sum of

(1) the cumulative amount (as of that date) allowed under this chapter for depreciation of the taxpayer's development costs for the lease or property; and

(2) the taxpayer's standardized prior-tax depreciation for the lease or property under § 630 of this chapter.

(g) A taxpayer depreciating its development costs for a lease or property for financial accounting purposes on a basis other than a variant of unit-of-production depreciation may apply to the department for authorization to use that other basis for purposes of calculating the deduction under this section. Upon a satisfactory showing that the taxpayer does use another basis for depreciating its development costs for financial accounting purposes, the department may grant the requested authorization to the taxpayer. Until that authorization is granted in writing, the taxpayer shall follow the method prescribed in this section to depreciate its development costs for leases or properties in the state for purposes of this chapter.

(h) The amount of a taxpayer's development costs for a lease or property equals the taxpayer's net payments for

(1) developments costs for facilities and equipment on or in support of the lease or property that directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property;

(2) tax paid under AS 43.56 to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property and ad valorem and other taxes paid to one or more municipalities under AS 29.53 that were incurred directly as the result of, and in the course of, the installation or operation of the property described in (1) of this subsection;

(3) that portion of the full consideration given by the taxpayer in acquiring a production interest in the lease or property, which is properly attributable to the wells, facilities and equipment on or in support of the lease or property which directly result in or are necessary for continued or enhanced production from (or allocated to) the lease or property (as opposed to the consideration given for the lease or property itself);

(4) interest on capital borrowed from one or more third parties for any of the expenditures described in (1) - (3) of this subsection that was capitalized for purposes of the taxpayer's financial accounting; however, interest so capitalized may be recognized for purposes of this chapter at a rate not to exceed the composite cost of the taxpayer's borrowed capital from third parties as reflected in the taxpayer's financial accounting for the year in which the interest is capitalized.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.320 EXTRAORDINARY OPERATING REVENUES AND LOSSES (OIL PIPELINES).
(c) The costs of permanently terminating operations and/or removing part or all of the facilities and equipment of a pipeline result in extraordinary operating losses for that pipeline. The amount of these extraordinary operating losses in a year, equals

(1) the amount of the unreimbursed termination and removal costs for that pipeline as may be allowed by FERC or other peremptory authority in a year prior to actual termination and removal according to specified factors and amounts in calculating net carrier operating income; or

(2) the unreimbursed termination and removal costs for the pipeline that are actually incurred that year, offset by the salvage value (if any) of the removed facilities and equipment and offset to the extent of any amounts allowed to be taken prior to actual termination and removal under this section and taken by the taxpayer.

If unreimbursed termination and removal costs for a pipeline are taken as a deduction and those costs are not actually expended or deduction of those amounts is disallowed by FERC or other peremptory authorities, then the amount so claimed must be recaptured as extraordinary operating revenue.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.020
AS 43.21.090

15 AAC 12.510 APPORTIONABLE INCOME. (a) A taxpayer's apportionable income for a year equals

(1) the net income worldwide of the consolidated business of which the taxpayer is a part, as determined and certified by an independent certified public accountant (or, as appropriate, the foreign counterpart of a certified public accountant, such as a chartered accountant) for purposes of reporting that year's earnings and profits to the stockholders; minus either

(2) the sum (if greater than zero) of

(A) the taxpayer's taxable production income that year under § 100 of this chapter;

(B) the taxpayer's taxable oil pipeline income that year under § 300 of this chapter; and

(C) the taxpayer's taxable gas pipeline income that year under § 400 of this chapter; or

(3) zero, if the sum in paragraph (2) of this section is less than or equal to zero.

(b) "Net income" as used in this section must be calculated without regard to any taxes on or measured by net income, and the amount of those taxes may not be reduced by any credits or carry-forward deductions incurred or available prior to January 1, 1978.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, § 18)
AS 43.21.040
AS 43.21.090

15 AAC 12.710 (f) A payment of less than $50,000 may be made by check in the manner prescribed in (1) of this paragraph or may be made by wire transfer in the manner prescribed in (2) of this paragraph. A payment of $50,000 or more must be made by wire transfer in the manner prescribed in (2) of this paragraph.

(1) A payment by check must be made by mailing the check, together with a copy of only the summary page (or pages) of the tax report, to the following address or other address as the commissioner may designate: Cashier, Department of Revenue, State of Alaska, Pouch SA, Juneau, Alaska 99811. A payment made by check or a return not requiring a payment will be considered timely if it is postmarked on or before the date or day of the month in which it is due.

(2) A payment by direct wire transfer must be made through the commercial banking system in accordance with the following procedures:

(A) As early as practicable and in no event later than 9:00 a.m. of the morning of the day when the wire transfer is to be made, the taxpayer shall notify the Alaska State Treasury by Telex (at Telex number 09045333) of the amount of the taxpayer's payment;

(B) the taxpayer shall obtain sufficient collected funds to cover the payment and shall instruct the commercial bank holding those funds to initiate the transfer of federal funds (in the amount of the payment) through the Federal Reserve wire transfer system to the credit of the State of Alaska Investment Account at the following address:

Bank of America, NT & SA
San Francisco, California
Securities Department #3255
Acct: State of Alaska Investment Account;

(C) the taxpayer shall make the payment in one lump sum from one bank;

(D) a payment made by wire transfer will be considered timely if the taxpayer's commercial bank has initiated the transfer of federal funds through the Federal Reserve wire transfer system on or before the last banking day of the month in which the payment is due, or on or before the last banking day prior to the date due, if the date due is not a banking day.

(3) "Payment" as used in this section, means the total amount due or estimated to be due by the taxpayer and arising under any provision of AS 43.21, including taxes, interest and penalty.

Authority: AS 43.05.080
AS 43.05.280
AS 43.21.070
AS 43.21.090

STATE
of ALASKA

MEMORANDUM

TO: Thomas K. Williams, Commissioner
Department of Revenue

DATE: February 29, 1980

FILE NO

TELEPHONE NO

FROM: Robert M. Johnson, Director
Petroleum Revenue Division

SUBJECT: Narrative for Fiscal Note to SB 474 (AS 43.21)

Proposed SB 474 incorporates a number of very substantial amendments to AS 43.21 as well as technical ones considered by the Department of Revenue. The bill would decrease AS 43.21 tax receipts by approximately $307.36 million in the first year (calendar year 1980) from an anticipated collection of $525 million during the same period.

Section 3 avoids a constitutional issue by amending AS 43.21.010 which presently provides that the tax applies to income derived from oil or gas from property "in or directly associated with the State." (Emphasis added.) The amendment would delete the emphasized words and clarify the fact that the tax is not designed to impose liability on a corporation whose only business is on the Outer Continental Shelf and not in Alaska. The proposal does not preclude some taxation of OCS operations, because income from OCS operations would be taxed as apportionable "other" income to the extent allowed in AS 43.21.040. The proposed amendment would, through clarification of the scope of the tax, strengthen the State's position in the income tax lawsuit (ARCO v State) without backing away from the contention that OCS operations may comprise a portion of apportionable income.

Sections 3 and 4 reduce the tax rate under AS 43.21 from 9.4 percent to 7.4 percent--that is, a decrease of 21 percent. The receipts would thus decline by about $110-130,000,000 in calendar year 1980 and more thereafter, if AS 43.21 were to remain identical to the existing law in all other respects. If, however, all the other amendments of this bill were adopted, a revenue decrease of $57.86 million would be attributable to the 21 percent change alone.

Section 5 would provide for distribution of at least 10 percent of the receipts under AS 43.21 to municipalities. Assuming a tax rate of 7.4 percent as proposed (but not assuming passage of other SB 474 measures increasing deductions), the amount subject to distribution in calendar year 1980 would be about $40 million and more thereafter. Assuming that this amount results in a reduction in local property taxes (as "intended" in proposed AS 43.21.016(d)), municipalities would levy less tax on petroleum property taxable by the State under AS 43.56. As less tax is collected on petroleum property by municipalities, the State receipts under AS 43.56 would increase by about $3.8 million, assuming a distribution of about $40 million to municipalities.

Section 6 would effectively eliminate the use of actual prices or prevailing value in ascertaining the sales price of oil or gas and the use of actual transportation costs in deriving the gross value at point of production. The gross value at point of production would be reduced, especially as at least the price of oil is exempted from Federal ceiling prices. The decreased value could arise if (a) a booked value, even under generally accepted accounting principles, is lower than an actual sales price between third parties or the prevailing value of oil or gas, and (b) the fair market value of transportation is higher than the actual value of transportation. While a general trend, based on experience so far, would be toward a lower booked price and a higher FMV for transportation, the specifics must analyzed on a case-by-case basis. Nevertheless, a reduction in value could be substantial and a loss of taxes in the range of $17 million for 1980 could be experienced.

Section 7 increases the deductions presently allowed under AS 43.21.020(c) in deriving production income.

First, section 7 amends (c)(2) to allow taxes paid or incurred as "windfall profits taxes" to the federal government as an additional deduction. The tax effect of this would be approximately $47 million in the first year and considerably more over time as the decontrolled price of oil escalates with general inflation and worldwide conditions. In making this estimate, I am assuming a Federal tax of 70 percent on the difference between a $13 base and a receipted price of $14.50 (less severance taxes).

Second, the bill amends (c)(3) and (c)(6) to provide that property taxes incurred, but not actually paid, may be deducted. This accrual-basis accounting would probably not decrease present receipts, but could do so if credits became available to shelter actual payments.

Third, the bill amends (c)(4) to allow drilling costs (including intangible drilling costs) to be expensed rather than capitalized and depreciated. This deferral of tax obligations would result in a first year decrease of tax receipts in the amount of about $72 million, assuming that only drilling costs incurred after the date of this bill can be expensed. If, however, the bill were read to allow the expensing of the undepreciated portion of previously capitalized drilling costs (an argument not favored by this Department), the deferred tax obligations for the first year could result in a much greater tax deferral. A taxpayer's level of drilling activity would of course dictate the amount of the deduction in a given year.

Fourth, the bill amends (c)(5) to permit those methods of depreciation referred to in rules based on the Internal Revenue Code to be used rather than the unit of production method or other methods devised by the Department of Revenue. The amount of additional taxes deferred by using an expanded variety of depreciation methods could decrease revenue receipts for the first year by $25 million if a taxpayer may switch to an accelerated depreciation method for existing capitalized costs being currently depreciated on the unit of production method, and if pre-1980 drilling costs are not expensed.

Fifth, the bill amends (c)(7) by clarifying which interest expense must be capitalized and which interest expense may be currently expensed and deducted in determining production income. The present provision allows all interest to be directly expensed unless it is required to be capitalized. However, recent accounting standards require that practically all interest expenses be capitalized as part of the cost of major capital improvements, and so forth. Thus, very little interest is left to directly expense under the existing statute. This amendment would also allow the Department, as necessary, to adjust or set aside interest expense from intracompany transactions, if those transactions are spurious. There would be a relatively small increase in taxes deferred, but that situation could change as major development increases.

Sixth, the amendments to the bill amend (c)(9) would drop the ceiling on general overhead on administrative expenses. The absence of the ceiling would allow additional deductions with a tax effect of $3.5 million to be taken currently.

Seventh, the bill would add a new deduction--an amortized portion of the anticipated costs of removing production facilities. A similar allowance is presently allowed by law as a deduction in deriving pipeline income. The amount of tax so deferred in the first year would be $2 million.

Section 8 of the bill would allow accelerated depreciation (under methods referred to in rules based on the IRC) in the calculation of pipeline income. Currently, the law permits only that type of depreciation to be taken which is allowed by FERC--and FERC allows only straight-line depreciation to be used. Taxes in the amount of approximately $36 million per year could thus be deferred in the first year. The accelerated depreciation would, of course, primarily benefit new capital improvements (i.e., the Natural Gas Pipeline, when constructed).

Section 9 of the bill proposes several amendments to the calculation of apportionable "other" income taxed under AS 43.21.040. These amendments would reduce tax receipts by about $5 million a year.

First, the bill would delete OCS operations from taxation as apportionable "other" income.

Second, the change in 40(b) would modify the "pie" of worldwide income from which Alaska takes a "slice" under apportionment. The new "pie" would exclude net worldwide production and pipeline income, since similar income directly attributable to Alaskan activity is identified in sections 20 and 30 of the Act.

Third, a new subsection would be added. That amendment would modify the formula used to determine the size of Alaska's "slice" of the worldwide "pie" by eliminating all marine transportation (tankers) from the property factor used in ascertaining apportionable "other" income.

Section 10 of the bill would modify the definition of "consolidated business." The change would avoid lumping, for example, ARCO together with Exxon simply because they might run a 50-50 joint venture in Alaska.

Finally, sections 10 and 11 provide for retroactive application to the beginning of tax year 1980 and set the effective date at July 1, 1980.

STATE
of ALASKA

MEMORANDUM

TO: Thomas K. Williams
Commissioner
Department of Revenue

DATE: February 5, 1980

FILE NO:

TELEPHONE NO:

FROM: Joseph K. Donohue JKD
Deputy Commissioner
Department of Revenue

SUBJECT: Impact of the Repeal of Individual Income Tax: Audit, Enforcement, and Administrative Services Divisions

The repeal of the individual income tax will have a very significant effect on the Audit, Administrative Services, and Enforcement Divisions. The immediate effect of a repeal will depend on the approach taken by the Legislature. There are three potential options which could be exercised. First, since there is a normal three year statute of limitations for audit purposes, the audit and enforcement functions could be funded in full for the three years following the date of the repeal of the tax. This would allow continuing audit of those returns filed prior to the repeal. Second, there could be a phaseout over three years of those functions related directly to individual income tax which would permit a declining audit and enforcement function which would be completely phased out by the end of the third year. Third, there could be an immediate cutoff of all funds effective beginning the first fiscal year after the repeal, in which there would be no continuing audit effort or enforcement effort regarding individual income tax returns.

In the following analysis where the impact is reviewed on a divisional basis, the positions being shown as eliminated are those positions which are currently working on individual income tax returns and are those which would be eliminated at the point of the final phaseout of the tax. Some of the positions could be eliminated immediately regardless which of the previous options were exercised, while others would continue on for up to three years.

AUDIT DIVISION

The major effect of a repeal would involve our various return processing units. The following table shows our currently authorized positions by unit, the number that would remain after a repeal, the number potentially eliminated by a repeal, and the total costs related to the eliminated positions.

Unit	Current Authorized Positions	Positions Remaining after Repeal	Positions that could be Eliminated	Total Cost, Eliminated Positions
Juneau Field Audit	5	4	1	$ 28,900
Juneau Taxpayer Assistance	6	1	5	105,400
Audit Files	10 PFT 1 Seas.	6 PFT 1 Seas.	4	80,500
Audit Control	3	3	-0-	-0-
Error Correction	3 PFT 4 Temp.	0	3 PFT 4 Temp.	134,350
Business Returns Proc.	6	6	-0-	-0-
Withholding/Excise	8	5	3	67,450
Taxpayer Compliance	1	-0-	1	28,950
Conference	1	1	-0-	-0-
Intelligence	3	-0-	3	123,800
Anch. Field Audit	7 PFT	6	1	28,900
Anch. Taxpayer Assistance	2 PFT 2 Seas.	1 PFT	1 PFT 2 Seas.	33,700
Fairbnks. Field Audit	2 PFT	2	-0-	--
Seattle Field Audit	7 PFT	7	-0-	--
Mgm't. & Support Staff	11 PFT	9	2	56,100
Totals	74 PFT 3 Seas. 4 Temp.	51 PFT 1 Seas.	23 PFT 2 Seas. 4 Temp.	$ 688,050

The above schedule provides for the potential reduction of staff based solely on the percentage of time that the staff currently spends working on individual income tax returns. It must be remembered that there are several tax types in which we have a very limited audit effort. The Auditors and Criminal Tax Investigators could easily be assigned to work on these other tax types. We also have been trying to obtain additional staffing to establish an effective office audit program of the various business and excise tax returns that are filed with us. We could very effectively employ four Tax Examiners and a Clerk in that function.

The table shows that the Compliance function would be eliminated based on current workload. It must be remembered that this is a new function and individual income tax is the least difficult area in which to start a function, thus providing some good experience while minimizing the complexities inherent in other tax types. This staff could easily be assigned on a full time basis the function of determining which companies have nexus with Alaska but are not filing returns with us. An additional two Tax Examiners could be assigned to compliance to work in other tax types such as fish processors, mining, or motor fuel.

We presently have no compliance effort in these areas and have reason to believe that there is a significant number of nonfilers in these areas.

Should the staff be reassigned as suggested above, these would require that we retain the Manager's position and the Clerk Typist support to manage the modified office operations program.

Finally, it would be necessary to retain several staff members to handle the remaining workload that would still exist in the area of individual income tax. As previously mentioned, the amount of staff would depend partially on the effective date of a repealer; however, we would continue to have individuals filing amended returns for prior years, requesting copies of their old returns, and seeking to obtain returned refund warrants. This workload would probably diminish the third year after repeal of the tax.

In summary, with the exception of three File Clerks, the seasonal positions and the temporary positions, it is obvious that we could very profitably use the displaced staff members to substantially enhance other aspects of our existing program that have little or no audit effort at this time.

ENFORCEMENT DIVISION

The impact of a repeal of the individual income tax would be very significant in relation to the Enforcement Division. During the past year 93% of their workload was related to the individual income tax. The present budget of $1,217,000 would be reduced to $111,950 and the positions would be reduced from 36 to 3. The following positions are the ones which would remain:

	Salary & Related Costs
1 - Revenue Enforcement Officer II	$ 55,800
1 - Tax Collection Specialist II	29,600
1 - Clerk Typist III	26,500
Total	$ 111,950

If this were to take place, there would be little logic to attempt to maintain Enforcement as an independent function. Rather, it could be merged with Audit Division and maintained as a separate unit within that division.

There is one major consideration which must not be overlooked when the repeal effect is contemplated. The repeal would not cause their workload to cease immediately. Rather, it would gradually decline over a several year period, leaving a residual workload that could be handled by the above listed staff. Therefore, the staff reduction should be planned over at least a three year period.

In analyzing what other ways these staff members could effectively be utilized, the obvious reassignment would be to the Child Support Enforcement Agency. This function, which is 75% funded by the Federal Government, collects child support due custodial parents who are not receiving AFDC and collects from the obligor (non-custodial parent) the amount due the State and Federal Governments if the mother is receiving AFDC. This agency has a total workload of in excess of 17,000 cases, the majority of which they cannot work on because of lack of staff. As the tax enforcement function is phased out, these employees could be transferred to the Child Support Enforcement Agency and generate substantial income in the form of repayments of AFDC which absent parents owe the State and Federal Governments.

ADMINISTRATIVE SERVICES DIVISION

A repeal of individual income tax would reduce the total number of Administrative Services employees from 68 to 34. The PFT (permanent full-time) employees would be reduced from 53 to 33. The 5 PPT and 9 temporary positions would be eliminated.

ADMINISTRATIVE SERVICES
LIST OF POSITION REDUCTIONS

Unit	Current Authorized Positions	Positions Remaining after Repeal	Positions That Could Be Eliminated	Total Cost Eliminated Positions
Management	6	5	1	$ 27,165
Supply	1	1	0	0
Personnel	4	3	1	19,155
Fiscal	5	3	2	47,355
Cashier	5	2	3	85,260
Publication	1	0	1	34,190
Document Processing	9	3	* 6	103,070
CETA-PSE	3	2	1	15,900
Data Processing	5	2	3	102,315
Business License	3	2	1	18,030
Mail	3	3	0	0
Data Entry	8	2	6	85,818
Fish & Game	9	9	0	0
Temporary (5 mos.)			2	13,850
Temporary (4 mos.)			7	36,575
Total				$ 588,683

* 5 positions are seasonal.

ALASKA STATE LEGISLATURE - HOUSE OF REPRESENTATIVES

REPRESENTATIVE JOE McKINNON
POUCH V. JUNEAU, ALASKA 99811

February 4, 1980

Thomas K. Williams, Commissioner
Department of Revenue
Pouch S
Juneau, Alaska 99811

Dear Tom:

Re: Proposed changes to 15 AAC 12; regulations on the Oil and Gas Corporate Income Tax

We are very concerned, as you know, over the proposed changes to the regulations on the Oil and Gas Corporate Income Tax (15 AAC 12). We urge you to postpone any action on these regulation changes until we have had more time to review them. Our specific concerns are the proposed changes to sections 240, 250 and 260, which provide for the direct deduction of drilling costs as operating costs. We are also concerned about allowing methods other than unit-of-production depreciation, which is the method specifically mentioned in the statutes.

During deliberations over the Oil and Gas Corporate Income Tax legislation, the Department of Revenue relied on work by Jerome M. Zeifman and Kenneth G. Ainsworth. In their January 1977 report entitled The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax, Ziefman and Ainsworth cite two major problems. The first was what they called an "eroded tax base". This was due to Federal tax subsidies historically provided to the petroleum industry. The second problem was that Alaska was using an apportionment formula, which did not fairly reflect the true amount of business being done in the state.

Both these problems stemmed from the fact that Alaska had delegated to Congress the responsibility for determining the corporate income tax base. By adopting certain provisions of the Internal Revenue Code, the State was inadvertantly adopting Federal deductions designed as tax subsidies. The most notable of these, as Ziefman and Ainsworth pointed out, was the "expensing of intangible drilling costs." Furthermore, by adopting an apportionment formula based on the Uniform Division of Income for Tax Purposes Act, the State was not taxing the petroleum industry on a manner which truly reflected their profits made in the State. The effect, as stated by Richard Kilgore of the Walter J. Levy Consultants Corporation before a joint House-Senate Resources Committee hearing on March 21, 1977, was "an effective rate of taxation instead of something like 9.4% a rate of taxation, roughly a quarter of that, two to two and a half percent."

That the intent of SCS CSHB 322 was to solve both of these problems is clear. In a letter dated July 5, 1978 to the House Speaker and Senate President, Governor Hammond wrote:

> Oil and gas corporations have been paying an effective tax rate substantially below the nominal tax rate of 9.4 per cent and substantially below what other local corporations would pay on the same income earned on the same assets in the state. The passage of this bill culminates three years of joint effort by the executive and legislative branches to rectify substantial defects in the former taxation scheme which, by incorporating various federally available tax loopholes and by using an inappropriate apportionment formula, allowed oil and gas corporations to avoid their fair share of the state tax burden. (1978 House Journal Final Supplement, p. 13).

To now reincorporate the "federally available tax loophole" of expensing of intangible drilling costs by regulation appears to be directly in conflict with the intent of AS 43.21. (ch 110 SLA 1978).

Plus, the fact that this proposed change to the regulations is of questionable legality is evident in the request for a legal opinion from Joseph K. Donohue, Deputy Commissioner of Revenue to Wilson Condon, Deputy Attorney General, dated November 2, 1979. The Department of Revenue claims the question of law centers around an interpretation of AS 43.21.020(c)(4), which defines operating expenses allowed as direct deductions. Under AS 43.21.020(c)(4), there is no specific reference to drilling costs. The Department has apparently mistakenly concluded that if drilling cost are not indirect costs, they may be deducted.

We would like to bring to the Department's attention AS 43.21.020(c)(8) which provides the only reference in the statutes which directly relates to "drilling costs." This subsection explicitly states that "dry hole" costs are allowed as direct deductions. We emphasize here that this apples only to "dry hole" costs and not drilling costs per se.

Returning to the legislative history on taxes in general, it is clear that SCS CSHB 322 was not the first attempt to rid the state tax base of "federally available tax loopholes." On February 25, 1975, Governor Hammond wrote to the House Speaker regarding HB 208:

> I am submitting this bill for the purpose of closing certain corporate tax loopholes. The bill would eliminate the foreign tax credit, the depletion allowance, and the exemptions for domestic international sales corporations (DISC), and would place a limit on the amount of investment credit for Alaska income tax purposes. (1975 House Journal 295).

After the passage of CSHB 208 (Fin.)am S (ch 153 SLA 1975), the only other significant "tax loophole" left was expensing of intangibles.

We understand that a large measure of your concern arises from the current lawsuit over AS 43.21. We believe that many of the complaints in the lawsuit can be rendered moot by changes to the statutes which will have little impact on revenue. We remind you of the letter the Attorney General wrote to Governor Hammond on June 22, 1978, in which Avrum Gross concluded, that:

> We herefore simply reiterate our advice to the Department of Revenue and state that, in our view there are no constitutional or legal issues which would be fatal to the implementation of the new income tax.

I think you can understand our concerns. We are available at any time to discuss them with you further, and also to work with you on statutory changes to which address sub stantive legal points concerning the lawsuit over AS 43.21. Please send us a copy of the latest annual consolidated report of state revenues and taxation policies required under AS 43.21.110.

Sincerely,

Joe

Joe McKinnon

cc: Joseph K. Donohue, Deputy Commissioner of Revenue
Rob Johnson, Director, Div. of Petroleum Revenue
Representative Terry Gardiner
Representative Russ Meekins

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF REVENUE

DIVISION OF PETROLEUM REVENUE

201 E. 9th AVENUE
ANCHORAGE, ALASKA 99501
PHONE: (907) 276-1363
(907) 277-5627

January 18, 1980

Re: Income Tax Regulations
(AS 43.21)

To Recipients of Proposed Regulations:

Proposals which would amend existing oil and gas corporate income tax regulations have been distributed to you. The most recent set of proposals followed a published notice which related that set of proposals to an earlier one distributed late in October 1979. It has come to our attention that the most recent set of proposals inadvertently dropped a couple of paragraphs contained in the earlier draft. The unintended deletions, which are obvious in the context of the proposals, are contained in proposed sections 132(b)(3) and (4), 240, and 900(31) and (32). The deleted language is attached.

We apologize for any inconvenience this has caused you.

Sincerely,

Robert M. Johnson
Director

Attachment

RMJ/rdm

04071LH

Proposed Regulation 132(b)(3) and (4) should read:

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by the taxpayer of that oil, the taxpayer's actual cost for that transportation, which is the sum of:

(A) voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(C) depreciation of the vessel; if the vessel is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this paragraph,

(i) "acquisition costs" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, but not including costs of improvements made after the date the vessel is placed in service by or on behalf of the taxpayer, and

(ii) "expected life" means the period of time used to calculate depreciation under (C) of this paragraph;

(4) in the case of transportation of gas as LNG,

(A) where not all of the LNG transportation facilities are subject to tariff regulations (by FERC or other agencies of the United States, state or territory or a possession of the United States or a foreign nation) and when the taxpayer does not have or effectively have any ownership interest in the LNG transportation facility, the amount charged to the taxpayer for that LNG transportation;

(B) when the taxpayer has or effectively has an ownership interest in the LNG transportation facility, the taxpayer's actual cost for that transportation equalling the sum of:

(i) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the taxpayer's gas;

(ii) the positioning cost, amortized over 36 months, for that vessel but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(iii) depreciation of the LNG transportation facility; if the facility is actually owned by the taxpayer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the taxpayer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iv) an amount which, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, and "expected life" means the period of time used to calculate depreciation under (iii) of this subparagraph;

Proposed Regulation 240 should read:

15 AAC 12.240. DEDUCTION FOR DIRECT OPERATING COSTS. (a) The direct operating costs during a year that are incurred by or for a taxpayer for a lease or property in the state are a deduction in determining the taxpayer's taxable production income for that year.

(b) Before the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs for geological and geophysical work conducted on the lease or property after the taxpayer has acquired a working interest in the lease or property;

(2) rentals and shut-in royalties paid in order to retain the lease or property;

(3) drilling costs for wells bottomed on the lease or property; and

(4) the costs for operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property, but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, the direct operating costs for that lease or property and the costs (excluding development costs but including drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(c) After the commencement of commercial production from (or allocated to) a lease or property, the direct operating costs for that lease or property are:

(1) the costs of operating the facilities and equipment on or for the lease or property which directly result in or are necessary for the continued or enhanced production from (or allocated to) the lease or property;

(2) the costs of drilling and/or operating wells bottomed on the lease or property; and

(3) the costs of operations conducted on or near the lease or property in support of drilling and/or development operations for the lease or property but excluding the actual development costs themselves; however, if the lease or property is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then the direct operating costs for that lease or property are the costs (excluding development costs but excluding drilling costs) that are incurred by the operator in operating that lease or property and which are reimbursable to the operator by the working-interest owners, under the terms of that operating agreement.

(d) No cost for the taxpayer's general overhead or administrative expense and no cost that is to be amortized or depreciated under secs. 250-260 of this chapter may be included in this section.

Authority: AS 43.05.080
AS 43.19.010 (Art. IV, sec. 18)
AS 43.21.020
AS 43.21.090

Proposed Regulation 900(31) and (32) should read:

(31) "sales delivery point" means

(1) for a taxpayer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the contract or agreement for that sale, except in the cause of a sale to which Sec. 132(d) of this chapter applies;

(2) for a taxpayer's oil not sold in a bona fide, arm's-length sale to a third party, the gate of the refinery to which that oil is ultimately transported; and

(3) for a taxpayer's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the sales price of the taxpayer's gas under Secs. 122 and 124 of this chapter.

(32) "sales price" is defined in Sec. 122 of this chapter.