

SCOMM

96:8

HB 207

Legislative Research Agency

Alaska State Legislature



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Juneau, Alaska 99801-2196

Phone: (907) 465-3991
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February 14, 1995

MEMORANDUM

TO: Representative Joe Green

FROM: Gordon S. Harrison, Director 

RE: Oil and Gas Incentive Programs
Research Request 95.072

You asked for information on state statutory provisions designed to provide an incentive for companies to explore for, develop, and produce oil and gas resources in Alaska. Specifically, you asked for a report that includes "analysis of which incentives have been used, and why, along with analysis of why the others have not been used; and any and all memoranda, findings of fact, or written determinations related to any approval or rejection of an application by a producer to use one of the incentive programs." This memorandum describes the major statutory incentives and presents basic information on their use. We obtained the information primarily from the administrators of the incentive programs. Included is a documentary record of all denials by the Department of Natural Resources of applications for the benefits of an incentive provision. This documentary record, with an accompanying letter, was provided by Jim Eason, outgoing director of the Division of Oil and Gas. We have had neither the time nor staff resources to undertake an independent assessment of the reasons why companies have used or not used the various incentives. Presumably companies have sought the benefit of an incentive when they thought their projects met the basic statutory criteria for eligibility. Whether the state agencies administering the incentives have unreasonably impeded access to them, or the incentives themselves are inherently ineffective in stimulating oil and gas projects, are questions beyond the scope of this memorandum.

Statutory oil and gas incentives and incentive programs involving exploration and royalties are administered by the Department of Natural Resources (DNR). Incentives involving taxes are administered by the Department of Revenue (DOR).

Tax Incentives Administered by the Department of Revenue

Two major tax incentives for oil and gas projects are administered by DOR: the economic limit factor (ELF) and the enhanced oil recovery (EOR) tax credit. Until December 31, 1994, when the provision died by way of an automatic "sunset" clause, the department also administered a special industrial investment tax credit for gas processing facilities and mineral developments.

Economic Limit Factor (ELF)

In Alaska, the nominal severance (production) tax rate on oil and gas is 15 percent of the gross value at the point of production, except for properties initially coming into commercial production after June 30, 1981, which pay 12.25 percent for the first five years of production. Under AS 43.55.013, these nominal rates are multiplied by a factor that varies from 0 to 1 depending upon the productivity of wells in the field and the overall productivity of the field. This factor is the ELF, and it is derived from a complex formula that includes the average number of barrels produced daily by each well, and the number of barrels produced daily by the entire field. If, for example, the ELF calculation results in a factor of .6 on a field paying a nominal severance tax of 15 percent, the effective tax rate is 9 percent. The accompanying table shows the average daily production, the nominal tax rate, the ELF, and the effective tax rate for all producing oil fields in Alaska for calendar year 1994.

The ELF derives its name from a basic purpose of the provision: it is intended to prolong production from a declining field by reducing the tax burden as the field approaches its "economic limit," which is the point at which operating costs (including taxes) equal gross revenue. However, because the ELF comes into play well before a field is in the vicinity of its economic limit, it does more than merely prevent the premature shutdown of a field. It also imparts to the basic severance tax structure a progressive character. That is, it produces a higher tax on larger fields, which are presumably more lucrative, and a lower tax on smaller fields, which are presumably more of a marginal economic proposition. In this respect it mimics in an imperfect but general way a tax on income, which economists usually consider to be the most efficient form of taxation. Therefore, the ELF is a basic feature of the state's severance tax structure, rather than an addendum designed to provide a special incentive. Nonetheless, the ELF creates a particularly strong set of economic incentives for the oil and gas industry, and for that reason it is included in this overview.

DAILY GROSS PRODUCTION and SEVERANCE TAX RATES for ALASKA OIL FIELDS CALENDAR YEAR 1994				
FIELD	Daily Gross Production (bbls)	Nominal Severance Tax Rate (%)	Average Economic Limit Factor (ELF)	Effective Severance Tax Rate (%)
NORTH SLOPE				
Prudhoe Bay	971,000	15.00	.986	14.79
Kuparuk	305,400	15.00	.864	12.96
Pt. McIntyre	100,600	12.25	.907	11.11
Endicott	90,400	15.00	.751	11.26
Lisburne	19,200	15.00	.000	0.00
Milne Point	12,200	15.00	.006	0.08
Niakuk	9,000	15.00	.035	0.53
Schrader Bluff	2,900	15.00	.000	0.00
North Prudhoe Bay	2,300	12.25	.000	0.00
West Beach	1,500	12.25	.000	0.00
Sag Delta	900	12.25	.000	0.00
COOK INLET				
McArthur River	36,300	15.00	.000	0.00
Middle Ground School	6,700	15.00	.000	0.00
Granite Point	6,000	15.00	.000	0.00
Swanson River	4,400	15.00	.000	0.00
West McArthur River	2,400	15.00	.000	0.00
Trading Bay	2,100	15.00	.000	0.00
Beaver Creek	400	15.00	.000	0.00

Source: Department of Revenue

The table shows that only large North Slope fields pay a significance severance tax: in 1994, production from the Prudhoe Bay field was taxed at an effective rate of 14.79 percent; Kuparuk at an effective rate of 12.96 percent; Endicott at an effective rate of 11.26 percent; and Pt. McIntyre at an effective rate of 11.11 percent. Two smaller fields paid virtually no severance tax in 1994: Milne Point production paid an effective severance tax of 0.08 percent, and Schrader Bluff production paid an effective rate of 0.53 percent. The other twelve producing fields paid no severance tax. Clearly the ELF creates an incentive for oil companies to explore for and develop small pools of oil in the vicinity of existing oil production infrastructure, such as around Prudhoe Bay and Cook Inlet. More generally, the progressive nature of the severance tax created by the ELF reinforces this favoritism of small fields (i.e., those with production under 150,000 bbls/day). While large and prolific fields pay a comparatively high tax, these fields are presumed to be sufficiently robust to bear the burden of the tax¹.

Application of the ELF formula is automatic—that is, it does not depend on a discretionary decision of the commissioner. Taxpayers determine their tax liability on the basis of production statistics which are reported to the state. Returns filed by taxpayers are subject to audit by DOR.

Enhanced Oil Recovery (EOR) Credit

To encourage oil production from declining fields in the United States, Congress in 1990 authorized a 15 percent federal income tax credit for the cost of tertiary EOR projects (Title 26 U.S.C. 43). The federal code is adopted by reference in Alaska's corporate income tax law (AS 43.20.021). To qualify for the credit, a tertiary EOR project must begin after December 31, 1990, and it must significantly increase the ultimate amount of crude oil recovered from a drilling operation located in the United States. Taxpayers take the state credit when they submit their corporate income tax return to DOR. The department is prevented by confidentiality statutes from revealing information about individual tax returns, and it therefore may disclose only aggregate data (and this only to the extent that the number of taxpayers is large enough to conceal the tax payment of an individual company). According to the Alaska DOR, for tax years 1991 through 1993, at least \$21 million in credits were claimed on initial tax returns. These returns are subject to audit.

¹Future production from the West Sak field may present an exception, as costs there are expected to be inordinately high. However, the ELF formula is sensitive to two threshold values--300 bbls/day/well and 150,000 bbls/day/field--so it is difficult to predict how the formula will work for this field in the absence of actual well and field production statistics.

Special Industrial Incentive Investment Tax (Expired)

In 1984 the Alaska Legislature created a special credit against a company's state corporate income tax for investments made after December 31, 1984 in a "gas processing project" and in "exploration, drilling of wells, development, or mining of minerals or other natural resources ... other than sand or gravel." The original legislation (Chapter 60 SLA 1984) prohibited credits on investments made after December 31, 1994, although it allowed unused credits to be carried forward through 1999. Thus, this provision expired at the end of last year. The department would not provide an estimate of the value of credits taken and would say only that "several corporations" took the credit during the last decade for projects that include an oil and gas production project in Cook Inlet and several natural gas and gas liquids projects on the North Slope. According to Bob Bartholomew, Deputy Director of the Division of Income and Excise Audit, DOR, the credit was not claimed for any non-oil and gas mining projects.

Exploration and Royalty Incentives Administered by Department of Natural Resources

State law authorizes the commissioner of DNR to include certain exploration incentives in state oil and gas leases, and to approve a reduction of the royalty terms of an oil and gas lease under certain circumstances. The discretionary character of these statutory programs, which require the commissioner to make a determination of the state's best interest before offering or approving a benefit, differentiate them from the incentive programs under the purview of DOR, which are self-executing. Statutory provisions for reducing royalties have changed over the years; however, repealed provisions may still be "alive" in active leases issued when the provisions were current, and they therefore remain relevant today.

Below is a brief discussion of exploration and royalty reduction provisions. Additional discussion and pertinent records submitted by Mr. Eason follows as an attachment.

Royalty Reduction Provisions

Currently, AS 38.05.180(j) authorizes the commissioner of the department to reduce the royalty on a producing oil field if the reduction is necessary to "prolong the economic life of an oil and gas field." Thus, this provision is designed to accomplish for royalties what the ELF is designed to accomplish for severance taxes: to prevent the premature shutdown of a producing field by "reducing costs in the later stages of production decline." The statute specifies that "the commissioner may not grant a reduction of royalty until two years' initial production from the field

has occurred and each lessee requesting the reduction has made a clear showing" that continued production is *uneconomic*.

The section of the state oil and gas leasing law which authorizes the commissioner to unitize leases, AS 38.05.180(p), also authorizes the commissioner to "establish, *change* or revoke drilling, producing, and *royalty* requirements of the leases. . ." being unitized (emphasis added). Companies have applied to the department for a reduction of the royalty terms of their leases under this provision. The department has rejected such applications on the grounds that it may only entertain applications for royalty reduction under the terms of AS 38.05.180(j), because the latter is a specific statute governing royalty reduction and AS 38.05.180(p) is a general provision authorizing "change" in the context of unitization. According to the legal interpretation of the department, a specific statute takes precedence over a general one. Use of AS 38.05.180(p) to change royalty terms is an issue in the current effort of British Petroleum to unitize the area of the Badami discovery.

Alaska Statutes 38.05.140(d) authorizes the commissioner to reduce royalties on certain minerals. Until 1978, the list included oil and gas. However, oil and gas were removed from this provision in 1978 (Chapter 155 SLA 1978). According to Mr. Eason's letter, the department never received an application for royalty reduction on an oil and gas lease under the provision, but a number of active leases today contain language from the statute prior to its amendment in 1978.

Until 1969, state law granted a five-year royalty reduction from 12.5 percent to 5 percent for the holder of a lease "who shall drill and make the first discovery of oil or gas in commercial quantities in any geologic structure. . ." (AS 38.05.180[a]). This discovery royalty reduction was included in all leases, and it was nondiscretionary in the sense that it did not require a finding of the commissioner that approval was in the best interest of the state. However, it did require the commissioner to decide whether production was from a new geologic structure or the extension of a known structure, and on this basis several applications were denied. Although repealed in 1969 (Chapter 65 SLA 1969), this provision was included in all leases issued up to that time. According to Mr. Eason's letter, two producing leases on the North Slope are currently enjoying the benefits of the discovery royalty reduction. Also, some 340 active leases contain the provision, "an indeterminable number of which could potentially produce future discovery royalty applications."

Exploration Incentives

Alaska Statutes 38.05.180(i) authorizes the commissioner to establish an exploration incentive credit (EIC) system for exploratory wells and geophysical work. The law permits up to half of the cost of the exploratory work to be taken as a credit against royalties, rentals, or severance taxes

Representative Green
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Page 7

due to the state. The department includes an EIC provision in leases that may need the additional enticement for companies to explore. Leases of attractive prospects do not carry an EIC provision. According to Mr. Eason's letter, there are currently 187 active leases with EIC provisions; 20 applications for EICs have been granted, and 1 denied. Apparently no lease sale since 1991 has included EIC provisions. The value of credits taken to date is about \$58.7 million.

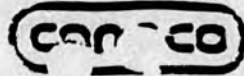
Last session, the legislature adopted SB 151 (Chapter 39 SLA 1994) that created additional exploration incentives that are "distinct from the exploration incentive credit authorized by AS 38.05.180(i). . . ." The new law, AS 41.09.010 applies to exploratory drilling and geophysical work "regardless of whether the land is state-owned land." Up to 50 percent of the cost of qualifying activity on state land may be taken as a credit against oil and gas corporate income taxes and lease bonus payments; 25 percent of the cost of qualifying activity on private land may be taken as a credit. No single project may receive a credit in excess of \$5 million, and no more than \$30 million in credits may be claimed during the ten-year life of the program. A company taking a credit must share with the state the raw data obtained from the exploratory well or geophysical survey. Regulations to implement this program have not yet been adopted.

The foregoing royalty reductions and exploration credits are addressed in more detail in the letter and documentary material from Mr. Eason, which is attached. I hope this overview of oil and gas incentives is helpful. If you have any questions or would like additional information, please call.

Attachments

ATTACHMENTS

Letter and Documents from James E. Eason to Gordon S. Harrison, February 8, 1995



David L. Bowler
Division Manager

Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503

February 27, 1990

RECEIVED

FEB 28 1990

DIV. OF OIL & GAS
DIRECTOR'S OFFICE

Ms. Lennie Gorsuch, Commissioner
State of Alaska, Department of Natural Resources
P. O. Box M
Juneau, Alaska 99811

Dear Commissioner Gorsuch:

(RE: Application for Royalty Reduction, Milne Point Unit, Conoco Working Interest in the Kuparuk River Participating Area

Attached is Conoco's application for a royalty reduction under the provisions of Section 18(h)(8) of the Milne Point Unit Agreement, and, alternatively, under the provisions of AS 38.05.180(j) and AS 38.05.180(p). This application requests an effective date of February 1, 1990, and requests a royalty reduction to 5% on all future Kuparuk River Formation production from ADL Leases No. 47433, 47434, 47437, 47438, and 28231.

Conoco also requests that all royalty payments after February 1 in excess of 5% be paid to a suspense account until final disposition of this application. Placing these royalties in a suspense account will facilitate final royalty adjustments after a decision has been reached by your Department, and may also lessen the time pressures that may be involved in reaching this decision. If DNR is willing to pursue this alternative, please have the appropriate DNR or Department of Revenue personnel contact me at their earliest convenience. The arrangements to establish this suspense account need to be finalized prior to the end of March.

Pursuant to 11 AAC 83.185(a)(5), Conoco hereby agrees to defray the cost of publishing any public notice required under 11 AAC 83.185(b).

This application contains cost and financial information that is confidential. Under the provisions of 11 AAC 82.810, Conoco requests that this entire application be held confidential. Conoco will submit a publicly available version of this application within 10 days of this filing. If this procedure is unacceptable to you, please provide us with 10 days notice before any proposed or possible release of any material so that we can take the necessary steps to protect our confidential interests.

Conoco believes that this application is complete and satisfies all of the application requirements contained in the Unit Agreement as well as all statutory and regulatory requirements. However, if you or your staff needs additional data, please contact Al Hastings at 564-7650.

Enclosure 1

000091

Ms. Lennie Gorsuch, Commissioner
February 27, 1990
Page 2

Thank you for your consideration of this application. This issue has been simmering for nearly seven years, and now is an appropriate time to reach a mutually satisfactory solution.

Very truly yours,


David L. Bowler
Division Manager

AEH(jr)
Attachment
(File

000092

CONOCO

David L. Bowler
Division Manager

Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503

Public

February 28, 1990

RECEIVED

FEB 28 1990

DIV OF OIL & GAS
DIRECTOR'S OFFICE

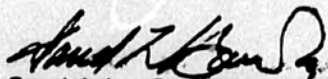
Ms. Lennie Gorsuch, Commissioner
State of Alaska, Department of Natural Resources
P. O. Box M
Juneau, AK 99811

Dear Commissioner Gorsuch:

Attached is the Public Version of the Royalty Reduction Application for the Milne Point Unit filed with your Department of February 28, 1990. Also attached is an errata page correcting a date in the previous application. The date in the Public Version has been corrected.

If I can be of further assistance, please give me a call at 564-7601.

Very truly yours,



David L. Bowler
Division Manager

AEH(jr)
Attachments
File 500.58.10

1
2 PUBLIC VERSION

3
4 BEFORE THE ALASKA DEPARTMENT OF NATURAL RESOURCES

5 In the Matter of:)
6 A Request by Conoco for)
7 Royalty Reduction on ADL)
8 47433, 47434, 47437, 47438)
9 and 28231 (Kuparuk)
10 Participating Area: Milne)
11 Point Unit).)

12
13 I. INTRODUCTION

14 Conoco owns a 72.149% interest in the Kuparuk Participating
15 Area of the Milne Point Unit. Four of Conoco's leases within the
16 participating area were acquired in 1969. The remaining lease,
17 ADL 28231, was originally issued in 1965, and acquired by Conoco
18 from Atlantic Richfield Company in 1988. All five leases were
19 executed on form ADL-1, and each provided a standard 12.5% royalty.

20 However, when Conoco and other companies participating in
21 Milne Point development petitioned the state for approval of the
22 Milne Point Unit in 1979, the Alaska Department of Natural
23 Resources ("DNR") refused to approve the unit unless the companies
24 agreed to a special royalty surcharge. As a result, the September
25 28, 1979 Milne Point Unit agreement, as drafted by DNR, requires
26 Conoco to pay a 20% royalty on the four 1969 leases. Attachment

These leases are referred to as the "1969 leases," and
include ADL 47433, 47434, 47437 and 47438.

BRUCE L. HORTON, DEPUTY ATTORNEY GENERAL
STATE OF ALASKA
JAN 24 1985
RE: STATE OF ALASKA v. CONOCO
1985-1006-1000

1 A, ¶14. Conoco continues to pay a 12.5% royalty on ADL 28231.

2 DNR informed Conoco, at the time, that the royalty surcharge
3 was being imposed in response to substantial oil price increases
4 that had occurred since 1969 -- increases that DNR believed would
5 allow a greater state share of Milne Point revenues without
6 impairing field profitability. According to DNR:

7 ...the economics of oil and gas leasing have
8 changed so drastically within the past ten
9 years that in order to effectively protect the
10 state's interests, certain changes in the
11 lease are necessary.

12 The royalty surcharge was an experimental policy that was
13 short lived. For example, when the proposed Kuparuk River Unit
14 came before the Department two years later, DNR approved it without
15 any required royalty increase.

16 The history of Milne Point's development and production is set
17 out in Exhibit A to the Affidavit of Alan Hastings. The working
18 interest owners in the Kuparuk Participating Area committed to
19 initial Kuparuk River Formation development in January, 1984. At
20 that time, ANS wellhead prices were about \$20/bbl., and were
21 expected to increase. Id. By the time production commenced in
22 November, 1985, however, ANS wellhead prices had dropped to

23
24
25
26 LeResche to High letter, September 19, 1979 at 1.
Attachment B.

1 \$14/bbl.' In comparison, the state believed at the time the
2 surcharge was imposed in 1979 that by 1985 ANS wellhead prices
3 would have reached \$34/bbl.'

4 Because of the decline in ANS prices, and Milne Point's
5 marginal production rates,' Milne Point owners could not hope to
6 recover their capital investment from projected unit production,
7 at least as long as the surcharge remained. Accordingly, on
8 November 1, 1985, Conoco and other Milne Point working interest
9 owners' requested DNR to reconsider its 1979 unit decision, and to
10 change the royalty requirements of the unit agreement under AS
11 38.05.180(p). The request, at the time, was limited to removal of
12 the 7.5% royalty surcharge. The companies' supporting papers
13 showed that, under the Department of Revenue's then-existing price
14 forecasts, and with the royalty surcharge, production from the
15 Kuparuk Participating Area would return only [] annually on the
16
17
18

19 ' Petroleum Production Revenue Forecast, Alaska Department of
20 Revenue, June 1985 at 11.

21 ' Petroleum Production Revenue Forecast, Alaska Department of
22 Revenue, December 1979 at 5.

23 ' During 1986, for example, production ranged from 10,000 to
24 15,000/bbl./day from the participating area, with peak production
forecasts ranging from 25,000 to 30,000/bbl./day.

25 ' These included Reading and Bates Petroleum Co., Champlin
26 Petroleum Co., and Cities Service Oil and Gas Corporation.

JOHN, BITTNER AND CHEROT
ATTORNEYS AT LAW
ONE MI ALASKA PLAZA, SUITE 101
JL NEAR ALASKA 99501
(907) 266-2800

MICHAEL J. BROWN, DEPUTY SECRETARY
ALASKA DEPARTMENT OF NATURAL RESOURCES
1000 EAST 10TH AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501
(907) 269-2000

1 company's capital investment.' Given Conoco's then-existing 15%
2 cost of capital,' projected Kuparuk Participating Area return would
3 be insufficient to allow the companies to ever recoup their capital
4 investment, much less earn any profit.

5 DNR never took final agency action on Conoco's 1985 request.
6 Rather, on February 5, 1986, DNR Commissioner Esther Wunnicke
7 proposed that the parties negotiate a royalty realignment, and
8 advised that:

9 I anticipate that staff would not be able to
10 continue evaluating your original [November 1,
11 1985] applications while actively negotiating
12 the remaining issues associated with our
13 proposed royalty alteration.'

14 Negotiations were unsuccessful, and DNR took no further action
15 on the 1985 application.

16 In the meantime, ANS wellhead prices plummeted. From the 1985
17 price of \$14/bbl. that provoked the company's 1985 request, Milne
18 Point's average wellhead price declined in 1986 to \$3.83/bbl."
19 These prices made continued production at Milne Point impossible;
20 and, in December, 1986, DNR granted Conoco permission to suspend

21 ' In the Matter of a Request by Conoco, et al, November 1,
22 1985 (hereinafter "1985 Request"), Affidavit of David Uldrich at
23 4.

24 ' Id.; Affidavit of Lou L. Pai at 1.

25 ' Wunnicke to Kemp letter, February 5, 1986 at 3 (Attachment
26 C hereto).

27 ' Hastings Aff. at Ex. I - J.

1 operations on the unit." Production was actually suspended in
2 January, 1987. Id.

3 Production from the Kuparuk Participating Area resumed in
4 April, 1989, with daily production reaching 20,000 barrels by the
5 end of the year. Id. During that year, Milne Point wellhead
6 prices averaged \$9/bbl. -- \$5/bbl. less than when the company
7 submitted its Request in November, 1985.¹²

8 This current Request for royalty relief is occasioned by the
9 fact that Milne Point production has crossed a threshold of sorts.
10 As of February 1, 1990, there have been two years production from
11 the field. Hastings Aff. at ¶5. During the suspension period,
12 DNR discouraged Conoco from pursuing royalty relief because both
13 §18(h)(8) of the Milne Point Unit agreement, and AS 38.05.130(j),
14 required two years' production as a precondition of royalty
15 relief.¹³ DNR has ruled that two years' production need not be
16 continuous; rather, according to DNR Commissioner Judith Brady, the
17 production history requirement "is tolled during the period
18 production is suspended."¹⁴ Excluding the tolled period of
19

20 " Id. at Ex. A.

21
22 " Hastings Aff. at Ex. I - J.

23 " The two year production requirement, however, does not
24 apply to a request to change royalty requirements under AS
30.05.130(p).

25
26 " Brady to Painter letter, April 29, 1987 at 1 (Attachment
D.)

BIRCH, HORTON, BITTNER AND CHIEROT
ATTORNEYS AT LAW
ONE SIX ALASKA PLAZA, SUITE 101
JUNEAU, ALASKA 99801
(907) 586-2800

1 suspension, production between November, 1985 and the present now
2 exceeds two years.

3 The change in royalty is sought under §18(h)(8) of the Milne
4 Point Unit agreement, which provides:

5 After two years initial production from the
6 field in which the leased area is located has
7 occurred, the State may reduce lessees
8 obligations to pay royalty on all of the
9 leased area or on any tract or portion thereof
10 segregated for royalty purposes upon (1)
11 request by a lessee and (2) a clear showing by
12 lessee that the revenue from all oil, gas and
13 associated substances produced from the field
14 is insufficient to produce a reasonable rate
15 of return with respect to lessee's total
16 investment in the field.

17 See Attachment A at 23-24.

18 As authorized by §18(h)(8), this request seeks a royalty
19 change only for that "portion" of the unit comprising the Kuparuk
20 Participating Area -- an area that will be segregated for royalty
21 purposes. Hastings Aff., ¶3. Conoco is requesting an amendment
22 to the royalty requirements of the unit agreement, and the
23 underlying leases, providing for a royalty of 5%. As the company's
24 supporting papers show, based on the Department of Revenue's
25 current mid-scenario crude oil price projections, a 20% royalty
26 will provide a rate of return of only [], far below the
company's cost of capital. At a 5% royalty rate, the crude oil
price must exceed the Department of Revenue's high scenario price
forecast by 20% for Conoco to just recover its cost of capital.
Thus, a royalty of no more than 5% is necessary to afford the
company any realistic opportunity to recover its capital costs.

1 The request also asks that the royalty change be effective as
2 of February 1, 1990 -- that date on which two years' initial
3 production was achieved. The purpose of §18(h)(8) -- to allow the
4 survival of marginal fields after two years' production experience
5 (see infra) -- would be best served by applying the relief at the
6 earliest possible date.

7 Conoco believes that §18(h)(8) is the most appropriate vehicle
8 for conforming Milne Point's royalty requirements to economic
9 reality. Section 18(h)(8) is a unique royalty reduction
10 requirement, inserted in the agreement to mitigate the impact of
11 the agreement's special royalty surcharge. It is worded
12 differently than the more general royalty reduction provision of
13 AS 38.05.180(j), and, as the Attorney General has already decided,
14 because §180(j) post-dated execution of Conoco's leases, it is the
15 unit agreement, rather than §180(j) itself, that establishes the
16 requirements for reduced royalties."

17 The special language of §18(h)(8) is absent from the unit
18 agreements governing other active units in the state. For example,
19 the Kuparuk River Unit agreement, lacking any special royalty
20 surcharge, likewise lacks any special provision for royalty
21 reduction. Thus, §18(h)(8) affords DNR the opportunity to tailor
22 royalty requirements to the economic conditions of Milne Point,
23 without affecting DNR's relationship with other lessees, or other
24 units.

25 _____
26 This to Brown Memorandum, "Conoco Milne Point Royalty
Reduction Request," April 24, 1984 at 5. Attachment E.

1 Alternatively, should the agency find that AS 38.05.130(j),
2 rather than §18(h)(8) of the unit agreement, governs this request,
3 Conoco has also met the requirements for a royalty change under
4 that subsection.

5 Finally, independent of both §18(h)(8) and §180(j), Conoco
6 remains entitled to a royalty change under AS 38.05.130(p).
7 Because DNR has never taken final agency action on its 1985
8 request, the company's entitlement to relief under that subsection,
9 and its request for reconsideration of DNR's 1979 surcharge
10 decision, remain before the Department. With respect to the 1985
11 Request, this request therefore:

12 1. modifies the 1985 Request by requesting a 5% royalty for
13 the Kuparuk Participating Area leases referenced above, rather than
14 removal of the royalty surcharge for the unit as a whole; and

15 2. updates the economic information in the 1985 Request based
16 upon new Department of Revenue oil forecasts, actual production
17 history, and other new economic information contained in this
18 request."

19
20
21
22 _____
23 " Should DNR decide that, by inaction or otherwise, it has
24 taken "final agency action" on the 1985 request, this request
25 should be considered as a new request for relief under §130(p).
26 Circumstances between 1985 and 1990 have changed. Because this
 request is based on facts different than those underlying the 1985
 request, even "final agency action" on the 1985 request would not
 limit Conoco's ability to pursue relief at this point. K. Davis,
 Administrative Law, 3rd Ed., §18.04.

BRUCE H. HORTON, BILL ENTERS AND CHIEF OF
ALASKA DEPARTMENT OF REVENUE
1000 EAST 10TH AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501
TEL: 581-2600

1 II. THE ECONOMIC JUSTIFICATION FOR A ROYALTY REDUCTION

2
3 Under §18(h)(8) of the Milne Point Unit agreement, a royalty
4 reduction is warranted upon a:

5 ...showing by lessee that the revenue from all
6 oil, gas and associated substances produced
7 from the field is insufficient to produce a
8 reasonable rate of return with respect to
9 lessee's total investment in the field.

10 Conoco has already made that showing, to DNR's satisfaction,
11 through its 1985 request; its request for suspension of production;
12 and its periodic royalty reports filed with the agency. With that
13 information before it, DNR was able to conclude on April 29, 1987
14 that:

15 Staff from the Division of Oil and Gas concur
16 with Conoco's economic assessment of the
17 losses incurred by continued production at
18 Milne Point, and agree that had those losses
19 been experienced over a two year production
20 history, a royalty reduction would be
21 advisable."

22 The supporting papers to this request both: (1) confirm those
23 losses, and Conoco's insufficient return, over two years of
24 production; and (2) show that, based upon the state's own price
25 projections, and with the royalty surcharge, the company will never
26 receive an adequate rate of return from Kuparuk Participating Area
27 production. 11 AAC 83.135 sets out the information needed for a
28 royalty reduction request, and by its terms seeks only historical

29
30 " Brady to Painter letter, supra note 14 at 1.

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1 data." The specific information required by §185(a)(2) - (4) is
2 provided, respectively, in Exhibits A and E - G of Mr. Hastings'
3 affidavit.

4 This request, however, goes further, and also provides
5 projected returns under varying royalty scenarios. See Hastings
6 Aff. at ¶11-12. Together, this data demonstrates that:

7 1. In November, 1985, the company's cost of capital was 15%.
8 Pai Aff. at p. 1. The company's current cost of capital is 12%.
9 Hastings Aff., ¶13. Thus, annual net income, net of royalties,
10 must be sufficient to allow the company to recover its capital,
11 plus allow a 12% rate of return in order for the company to break
12 even. Pai Aff. at Attachment B; Hastings Aff. at ¶¶13-14. Income
13 greater than that amount would result in profit. Income less than
14 that would represent a loss. Id.

15 Exhibit E to the Hastings Affidavit shows that Conoco's total
16 capital investment in the Kuparuk Participating Area has been
17 \$222.9 million. Exhibit F reports Conoco's operating income for
18 1986 and 1989, respectively, at \$8.76 million and \$19.37 million.
19 Operating income during those years, then, was [] and [],
20

21
22
23
24
25 " For example, the regulation asks for a description of "all
26 past and present activities"; seeks production data "during the six
months preceding...the application"; and cost and income data for
"the entire life of the lease."

1 respectively, of total capital investment." As a result, during
2 the two years of production, Conoco has been unable to meet the 12%
3 rate of return threshold, even if no operating income were assigned
4 to capital recovery. It was as though a bank, needing 12% interest
5 on a loan to cover its cost of borrowing, received only []
6 interest and no payment on the principal.

7 This historical data is a reliable indicator of future losses.
8 Granted, production to date has not exceeded 20,000/bbl./day,
9 while Conoco projects that 1990 production may approach
10 24,000/bbl./day. Hastings Aff., Ex. I - J. On the other hand,
11 additional capital expenditures will be made in 1990 in order to
12 achieve that increased production. Two additional wells have
13 already been drilled for the participating area, and two more are
14 scheduled during this calendar year. Id. at Ex. A. As a result,
15 from historical data alone, DNR may comfortably conclude that
16 revenues from the participating area will be insufficient to allow
17 Conoco to recover its capital, much less realize "a reasonable rate
18 of return with respect to lessee's total investment in the field."

19 2. The Hastings Affidavit also appends projections of future
20 costs, revenues and rates of return. Id. at Ex. I - J. These

21
22 " These percentages overstate the relationship of operating
23 income to capital costs since, for example, 1989 income is
24 expressed in 1989 dollars, while capital costs are expressed in
25 nominal dollars for the year in which they were incurred. That
26 overstatement is partially offset by the fact that 1989 operating
income reflects only 9 months of production. On balance, however,
the nominal relationship between the figures is sufficient to show
that revenues have been substantially less than those necessary to
ever recover the company's capital investment and cost of capital.

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1 attachments employ the same methodology used by Conoco in 1985 to
2 project future revenues. See 1985 Request, Uldrich Affidavit. The
3 revised projections reflect, among other intervening changes:

- 4 a. lower Department of Revenue price forecasts;
5 b. differing operating and capital costs, based on two years'
6 actual experience; and
7 c. the loss in the real value of production income because
8 production was delayed because of the suspension. Hastings Aff.,
9 at ¶10.

10 Those projections show that, with a 20% royalty, total cash
11 flow revenues will average only [] of total capital investment.
12 To break even -- that is, to yield revenues equal to the amount
13 necessary to recover Conoco's capital and yield a 12% rate of
14 return -- requires both a royalty of 5% and a crude price
15 significantly above current mid-scenario projections. That is the
16 royalty sought by this request. While DNR cannot control oil
17 prices, it can control the other variable affecting capital
18 recovery -- the royalty. Without a reduction in the royalty to 5%,
19 the company has no realistic chance at recovering its capital, even
20 with significantly higher oil prices.

21
22 III. ROYALTY RELIEF SHOULD BE GRANTED UNDER §18(h)(8)
23 OF THE MILNE POINT UNIT AGREEMENT
24

25 Conoco's ADL-1 leases allowed a royalty reduction whenever the
26 Commissioner found it "necessary for the purpose of encouraging

MR. G. BROWN: REINTER CONCHEROT
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1 the greatest ultimate recovery of oil and gas." In 1978, the
2 legislature tightened the conditions under which royalties could
3 be reduced on future oil and gas leases. Ch. 155, SLA 1978; AS
4 38.05.180(j). However, the company's leases incorporated Alaska
5 statutes only as they existed at the time of lease issuance (see
6 ADL-1, ¶42), and Ch. 155, SLA 1978 operated prospectively only.
7 State of Alaska v. Pulp America, Inc., 674 P.2d 268, 272 (Alaska
8 1983).

9 Both DNR and the Attorney General have concluded that the 1978
10 legislative changes did not, in and of themselves, amend the
11 royalty reduction provision of Conoco's leases.¹⁰ Rather, and as
12 these agencies have acknowledged, Conoco's contractual right to a
13 royalty reduction under its leases would be altered only by a
14 subsequent contract between DNR and the company -- in this case,
15 the Milne Point Unit agreement. Id.

16 The unit agreement does alter Conoco's right under its leases
17 to a reduction of the lease royalty." It did so, however, not by
18 following the language of §180(j), but rather by creating a special
19 royalty reduction provision in §18(h)(8).

20 The reason for this special royalty reduction provision is
21 apparent. The royalty surcharge in the unit agreement was imposed

23 ¹⁰ Brown to Haley letter, October 9, 1984 at 2 (Attachment F);
24 Thie to Brown letter, note 15, supra at 4 - 5.

25 ¹¹ It does not, however, purport to alter the Commissioner's
26 authority under AS 38.05.130(p) -- a separate issue that is
addressed in the company's 1985 Request.

MILNE POINT UNIT AGREEMENT
DNR ALASKA
1979

1 because of DNR's expectation of high oil prices, and substantial
2 industry profits." The surcharge was the result of a new and
3 experimental policy. To guard against the possibility that DNR's
4 price assumptions were wrong, or that the experiment would impair
5 field development, DNR also needed to preserve flexibility in
6 adjusting future royalties as an integral part of its new policy.

7 The special royalty surcharge, and special royalty reduction
8 provisions, thus went hand-in-hand -- a fact apparent from the
9 history of the unit agreement. As originally drafted, the
10 agreement contained neither a royalty surcharge nor any special
11 royalty reduction provision. See Attachment G. Rather, §18(h) (8)
12 first appeared in the September, 1979 draft that also first
13 proposed the royalty surcharge -- a draft prepared by DNR and
14 presented to the companies on a take-it-or-leave-it basis."
15 Section 18(h) (8) was thus as consciously tailored to Milne Point
16 as the royalty surcharge itself.

17 The parties' intent to treat royalties, and royalty
18 reductions, differently for Milne Point than for other units is
19 also apparent by comparing the Milne Point Unit agreement with the
20 agreements governing other active units in the state. After Milne
21 Point, the next major unit approved by DNR was the Kuparuk River

22 _____
23 " See page 2, supra.

24 " Compare LeResche to High letter, note 2, supra, and
25 LeResche to High letter, October 23, 1979 (Attachment H) (DNR
26 "intends to approve" the unit agreement precisely as presented by
DNR in the September 19, 1979 draft containing the royalty
surcharge/royalty reduction language.)

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1 Unit in December, 1981. By then, the State had abandoned its
2 policy of demanding royalty surcharges as a condition of unit
3 approval. The Kuparuk River Unit agreement thus contains no
4 royalty surcharge, and neither does it include any special
5 treatment of royalty reductions. Rather, the Kuparuk agreement
6 implicitly leaves royalty reductions to current general law,
7 including §180(j), by incorporating all applicable laws "in effect
8 on the effective date [of the unit agreement]" into the unit
9 agreement itself. Id., section 17.1.

10 The Milne Point Unit agreement also contains a general clause
11 incorporating then-applicable law. That boilerplate proviso,
12 however, does not affect the special treatment given royalty
13 reductions in §18(h)(8). First, section 1 of the Milne Point Unit
14 agreement incorporates then-existing law only to the extent that
15 it is "not inconsistent with the terms [of the unit agreement]" -
16 - a limitation conspicuously missing from section 17 the Kuparuk
17 River Unit agreement.

18 Second, there would have been no need for DNR to propose
19 special royalty reduction language in §18(h)(8) if the agency
20 intended to simply leave the royalty reduction question to §180(j)
21 pursuant to §1 of the unit agreement. It is common, of course, for
22 government contracts to broadly incorporate entire government
23 codes, but then specifically deal with a particular topic that is
24 also covered by those generally incorporated laws. In that case,
25
26

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1 the contract's specific treatment of the subject will prevail."
2 The reasons are obvious:

3 (1) where a contract specifically deals with the parties'
4 rights or obligations (as §18(h)(8) does here with respect to
5 royalty reductions), the parties are entitled to presume that the
6 language of the specific section was purposeful and complete;

7 (2) thus, imposing different or supplemental conditions on
8 exercising that right through a general incorporation clause would
9 be inconsistent with the specific section;

10 (3) in most cases, and certainly here, there is no indication
11 that the parties considered the specific subject matter (here
12 royalty reductions) when reviewing the general incorporation
13 clause; and

14 (4) the incorporation clause is a mere form provision, which
15 provides a particularly weak basis for modifying the terms of the
16 specific provision. Id.; Craig Taylor Equipment Co. v. Pettibone
17 Corporation, 659 P.2d 594 (Alaska 1983) (form contracts are
18 construed against the party providing the form).

19 Since, as the parties agree, only the unit agreement could
20 change Conoco's contractual entitlement to royalty relief in the
21 original lease, and since §18(h)(8) of the unit agreement treats
22 the issue of royalty relief in a specific and comprehensive way,
23 that section governs Conoco's entitlement to relief in the present
24 case.

25 _____
26 " McBride, Government Contracts, Matthew Bender, 1989,
section 2.150 at 2-305.

1 IV. IN THE ALTERNATIVE, CONOCO IS ENTITLED TO RELIEF
2 UNDER AS 38.05.180(j)
3

4 AS 38.05.180(j) comprises two sentences. The second sentence
5 is essentially identical to §18(h)(8) of the unit agreement, and
6 provides:

7 The Commissioner may not grant a reduction of
8 royalty until two years initial production
9 from the field has occurred and each lessee
10 requesting the reduction has made a clear
11 showing that the revenue from all hydrocarbons
produced from the field is insufficient to
produce a reasonable rate of return with
respect to that lessee's total investment in
the field.

12 As it has under §18(h)(8), Conoco has made this showing for
13 the purposes of §180(j).

14 While this second sentence limits the Commissioner's authority
15 to grant any royalty reduction, the first sentence of §180(j) deals
16 with a different issue -- the imposition of a mandatory obligation
17 on the Commissioner to write regulations authorizing royalty
18 reductions in particular cases:

19 To prolong the economic life of an oil and gas
20 field, the Commissioner shall adopt
21 regulations for all bidding methods to allow
22 reduction of royalty on leases within the
field to compensate for increasing costs in
the later stages of production decline.

23 Emphasis added.

24 Even if this first sentence also served as a limitation on
25 DNR's authority to grant any royalty reduction -- that is, if a
26 royalty reduction were allowable only "to prolong the economic life

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1 of an oil field," and then only if the reduction was needed "to
2 compensate for increasing costs in the later stages of production
3 decline" -- Conoco would meet those standards. First, there is no
4 question that granting the relief sought by this request would
5 prolong Milne Point's economic life. The nearly two year shut-in
6 period is evidence enough of Milne Point's peculiar economic
7 susceptibility; and, the conclusion is inescapable that if the
8 companies continue to suffer the substantial losses demonstrated
9 by this request's supporting papers, the economic life of Milne
10 Point would be materially reduced.

11 Milne Point is also in the "later stages of production
12 decline." Conoco is already engaged in secondary recovery.
13 According to then DNR Deputy Commissioner Jack Roderick, the
14 purpose of the first sentence of §180(j) was "to save the field,"
15 and avoid "possible premature abandonment." Minutes, House
16 Resources Committee, March 16, 1978 at 3. Under the first sentence
17 of §180(j), then, the legislature sought to encourage producers to
18 invest in secondary and tertiary recovery by ensuring that royalty
19 rates could be reduced in order to compensate for those increased
20 costs.

21 The purpose of §180(j)'s first sentence neatly fits Milne
22 Point. As the Hastings' Affidavit explains, Milne Point has been
23 engaged in costly secondary recovery, through water flooding, since
24 the onset of production. Id. at ¶4. Secondary recovery has been
25 used from the outset of production in order to avoid an immediate
26 and substantial drop in reservoir pressure that would have impaired

1 future production from the field. Because of low initial reservoir
2 pressures in the Kuparuk River formation, conventional primary
3 production could have resulted in gas saturation of the formation's
4 oil reserves, making subsequent water flooding far less effective,
5 and significantly reducing ultimate total recovery. Id. Had
6 secondary recovery not commenced from the outset, the useful life
7 of the reservoir would have been reduced, and commercial
8 development of the field would have been questionable. Id. As a
9 result, Milne Point presents precisely that kind of situation which
10 the legislature intended to address in §180(j)'s first sentence.

11 However, it is doubtful that the legislature ever intended
12 that the first sentence of §180(j) would modify the second. The
13 two sentences, after all, address different purposes -- the first
14 requiring DNR to draft regulations for royalty reductions to
15 compensate for secondary and tertiary recovery, while the second
16 defines the Commissioner's authority to grant royalty reductions
17 generally. In describing the purpose of §180(j) to the House
18 Resources Committee, the Legislative Affairs Agency described the
19 new royalty reduction provision as "retaining" the Commissioner's
20 authority "to reduce the royalty rate on tracts having marginal
21 production."³ Section 180(j) is consistent with that broad
22 characterization only if the second sentence stands on its own.

23
24 ³ Erickson to Osterback memo, March 15, 1978 at 1.
25 Characterization was made with reference to the original version
26 of HB 854, which, as to the first sentence of §180(j), was
identical to the version ultimately enacted. See HB 554, p. 3, ls.
4 - 7.

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1 Additionally, if the first sentence implicitly limits the
2 second, then the two-year production requirement of the second
3 sentence becomes superfluous." The purpose of the two year
4 production limitation in §180(j) was to prevent a person from
5 offering a high royalty or net profit share bid, and then
6 immediately seeking to reduce that royalty after the lease sale."
7 The second sentence of §180(j) assures that the lessee will have
8 at least two years of production before seeking to change his bid
9 royalty. Yet if the first sentence of §180(j) already limited any
10 royalty reduction to the "later stages of production decline," then
11 there was no need to specify a particular production period in the
12 second sentence." The only way of accommodating the two year
13 production limitation of the second sentence and the "later stages
14 of production decline" limitation of the first sentence, such that
15 each serves a different purpose," is to conclude that the two
16 sentences address different matters.

17
18 " And, of course, every portion of a statute is presumed to
19 serve an independent purpose. Isakson v. Rickey, 550 P.2d 359, 364
20 (Alaska 1976).

21 " Testimony of DNR Commissioner Jack Roderick, House
22 Resources Committee, March 2, 1979, tape 71 at 1024; Testimony of
23 Milton Lipton, House Resources Committee, tape 71 at 1687.

24 " In some cases, such as Milne Point, production decline
25 requiring artificial recovery techniques may occur from the onset.
26 However, even in those cases, production would have to commence
before the first sentence would allow for a royalty reduction.

26 " Isakson v. Rickey, 550 P.2d at 364.

1 In summary, Conoco need not meet the first sentence of §180(j)
2 in order to obtain royalty relief under that statute; yet, even if
3 it must, the secondary recovery investments that the company has
4 made in order to combat what would otherwise be a rapid decline in
5 natural reservoir pressure places Milne Point both within the
6 language and purpose of the entire section.
7

8 V. CONOCO REMAINS ENTITLED TO RELIEF UNDER AS 38.05.180(p)

9 DNR's legal authority to change Conoco's royalty requirements
10 under AS 38.05.180(p) are set out in the company's 1985 Request,
11 which are incorporated in this request by reference and need not
12 be repeated here. The economic justification for granting that
13 relief is set out in part II of this request, and the request's
14 supporting papers. Conoco requests that DNR either: (1) grant the
15 company's 1985 Request, as modified by this request to require a
16 5% royalty for the above referenced leases in the Kuparuk
17 Participating Area; or (2) treat this request as a separate
18 submittal under §180(p), or the commissioner's reconsideration
19 authority, and grant the requested relief.
20

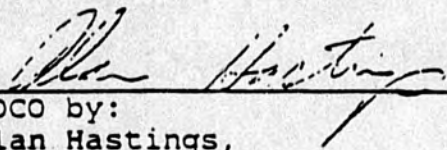
21 VI. CONCLUSION

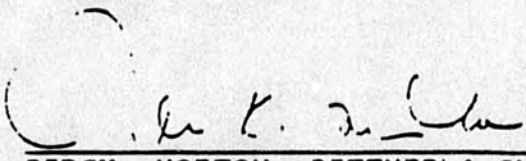
22 For the foregoing reasons, Conoco respectfully requests that:

- 23 1. the royalty on the above-referenced leases for the Kuparuk
24 Participating Area be reduced to 5%; and
25 2. the royalty change be made effective as of February 1,
26 1990.

ALASKA DEPARTMENT OF REVENUE
DIVISION OF OIL AND GAS
1000 EAST 10TH AVENUE, SUITE 100
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(907) 269-1200

1 DATED this 28th day of February, 1990.

2
3
4 
5 CONOCO by:
6 Alan Hastings,
7 Director of External Affairs

8 
9 BIRCH, HORTON, BITTNER & CHEROT by:
10 Jonathan K. Tillinghast,
11 Attorney for Conoco
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ATTACHMENT A TO CONOCO BRIEF

MILNE POINT UNIT AGREEMENT

DATED 9/28/79

ENCLOSURE 2

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June 1, 1990

DEPARTMENT OF
NATURAL RESOURCES

JUN 4 1990

COMMISSIONER'S OFFICE
JUNEAU

Commissioner Lennie Gorsuch
Department of Natural Resources
400 Willoughby Avenue
Juneau, Alaska 99811

Re: Application for Royalty Reduction, Milne Point Unit,
OXY USA Inc. Working Interest in the Kuparuk
Participating Area
Our File No.: 401553.1

Dear Commissioner Gorsuch:

Attached is OXY USA Inc.'s ("OXY") application for a royalty reduction under §18(h)(8) of the Milne Point Unit Agreement and, alternatively, AS 38.05.180(j) and AS 38.05.180(p). This application requests an effective date of February 1, 1990 for the royalty reduction, and requests a reduction to 5% on all Kuparuk River Formation production from ADL leases number 47433, 47434, 47437 and 47438. The application is supported by its own attachments, and also by the materials submitted by Conoco in November, 1985 and February 27, 1990. The Conoco materials are incorporated into this application by reference.

This application contains cost and financial information that is confidential. Both a confidential and publicly available version of the application are enclosed. Under the provisions of 11 AAC 82.810, OXY requests that the entire confidential application be held confidential under that regulation. If this procedure is unacceptable to you, please provide us with 10 days' notice before any proposed or possible release of any material so that we can take the necessary steps to protect our confidential interests.

OXY also requests that all royalty payments after February 1 in excess of 5% be paid into escrow until final disposition of this

Enclosure 2

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ANCHORAGE, ALASKA
JUN 11 1990

Commissioner Lennie Gorsuch
June 1, 1990
Page 2

application. Placing these royalties in a mutually agreeable escrow account will facilitate final royalty adjustments after a decision has been reached by your department, and may lessen the time pressures that may be involved in reaching this decision. If DNR is willing to pursue this alternative, please have the appropriate DNR or Department of Revenue personnel contact me at their earliest convenience.

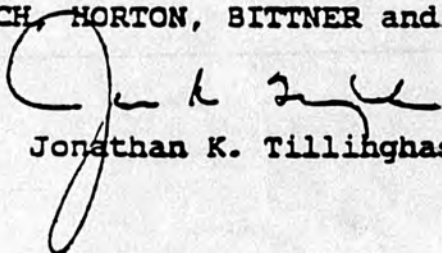
Pursuant to 11 AAC 83.180(a)(5), OXY hereby agrees to defray the cost of publishing any public notice required under 11 AAC 83.185(b). OXY also agrees to reimburse the reasonable transportation costs, and subsistence costs at normal state per diem rates, of a state auditor to conduct an audit at OXY's Tulsa, Oklahoma offices, of any information contained in this application.

OXY believes that this application is complete and satisfies all of the applicable requirements contained in the unit agreement, and pertinent statutes and regulations. However, if you or your staff need additional data please contact me.

Thank you for your consideration of this application.

Sincerely,

BIRCH, HORTON, BITTNER and CHEROT



Jonathan K. Tillinghast

JKT/amw

001281

ENCLOSURE 3

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

CERTIFIED MAIL -- Return Receipt Requested

April 17, 1991

Mr. David L. Bowler
Division Manager
Conoco, Inc.
3201 C Street, Suite 200
Anchorage, AK 99503

Dear Mr. Bowler:

The review process of the Conoco and Oxy USA applications for royalty reduction from 20 percent to 5 percent on the Milne Point Unit Kuparuk production has concluded. Based on the failure to show any net public benefit, I am denying these applications for royalty reduction.

The extensive records on these applications indicate that the profitability of the Milne Point Unit has not achieved the companies' desired level. However, the State as a royalty owner has no authority or responsibility to guarantee the success or profitability of a leasee's investment decisions.

The State of Alaska has given this marginal oilfield significant help by severance tax relief; a further grant of up to \$100 million through royalty relief is not warranted. The State as a royalty owner will not share in the risk of the companies' decisions.

However, there are a couple circumstances in which it may be in the public interest for the royalty owner to reduce its share of the current production to gain a long-term payback benefit.

At some point in an oilfield's later life the production revenue (excluding the royalty barrels) will not be sufficient to cover all the cash costs and operations may cease absent royalty reduction. This is not the current situation in the Milne Point Unit where production revenues from the Kuparuk formation are at the \$4-to-5-million per month level compared to operating costs of \$1-to-1.5 million per month. This circumstance of reaching the "economic limit" of production operations is projected by the companies to occur in a couple decades and can be considered at that time.

A second circumstance in which a royalty owner may choose to help the producer is to encourage further investment that has a direct net benefit to the state. In this situation, the data does not

Enclosure 3

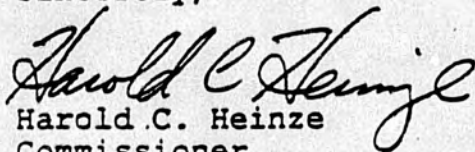
Mr. David L. Bowler

- 2 -

April 17, 1991

indicate that increasing profitability through a royalty reduction would result in an incremental prospective investment that could have an incremental direct benefit to the State large enough to offset the royalty loss. While this circumstance may occur in the future, the current submittal asks the State to give up over 5 million barrels of royalty oil for a potential reward replacing only a few percent of that loss.

Sincerely,


Harold C. Heinze
Commissioner

cc: John Tillinghast, Attorney
Birch, Horton, Bittner & Cherot
James Eason, Director
Division of Oil and Gas

DECISION OF THE COMMISSIONER
ON CONOCO'S APPLICATION FOR ROYALTY REDUCTION

Conoco, Inc. submitted an application to the State of Alaska Department of Natural Resources (DNR). That application requested that the State's royalty share of oil and gas produced from the Kuparuk River formation underlying five Milne Point leases be reduced from twenty percent to five percent.

Conoco's application was analyzed by the staff of the Division of Oil and Gas. Mark Myers, Petroleum Geologist, conducted a public hearing on the application, then prepared a Recommended Decision on Conoco's application. The Recommended Decision was accompanied by, and incorporated by reference, an economic analysis of the application prepared by Edward Phillips, Petroleum Economist (retired).

Normally, the Commissioner of the DNR would act on a recommended decision without further input from Conoco. However, Conoco requested and was granted thirty days in which to comment on the Recommended Decision. Conoco's comments consisted of fifty-one pages of text and twenty pages of affidavits, all of which have now been reviewed by this Commissioner.

As Commissioner, I hereby adopt the Recommended Decision as the final decision of DNR, subject to the additional findings and conclusions set forth in the remainder of this Final Decision.

In this Final Decision I do not undertake to address every alleged fact and argument raised by Conoco in its final comments. The bulk of Conoco's final comments simply state alleged facts and arguments which the hearing officer found inaccurate, unsupported,

or unpersuasive in his Recommended Decision, and which I, too, find inaccurate, unsupported, and unpersuasive. However, portions of Conoco's final comments suggest basic misunderstandings which may be cleared up by a few short words here.

First, the Milne Point Unit Agreement is not an agreement between the State of Alaska and Conoco. It is an agreement between all parties owning a working interest or overriding royalty interest in any lease within the Milne Point Unit. The State of Alaska is not a party to the Unit Agreement; rather, it simply approved the Agreement, subject to certain non-negotiable conditions. Conoco's allegation that paragraphs 1 (Enabling Act and Regulations), 14 (Royalty Settlement), and 18(h)(8) (Reduction of Royalty) of the Unit Agreement were the result of intricate negotiations between the State of Alaska and Conoco is not supported by the record. Nor is Conoco's allegation of linkage between paragraph 14 (increasing the royalty rate from 12.5 percent to 20 percent) and paragraph 18(h)(8) (limiting the availability of royalty reduction).

Second, pursuant to paragraph 14 of the Milne Point Unit Agreement, only five of the leases within the Milne Point Unit are burdened with a twenty percent royalty rate.¹ The remaining leases within the Unit have a 12.5% royalty rate. But paragraph 18(h)(8) of the Milne Point Unit Agreement, by its terms, applies equally to all applications for royalty reduction, whether the royalty rate of the subject leases is 12.5 percent or 20 percent. If there was the

¹ These five leases would have expired for failure to drill but for the State's approval of the Milne Point Unit Agreement.

linkage between paragraphs 14 and 18(h)(8) which Conoco suggests, then I would expect paragraph 18(h)(8) to set forth two sets of criteria for royalty reduction, one applicable to leases with a 12.5 percent royalty rate, and another for leases with a 20% royalty rate.

Third, while the Milne Point Unit Agreement may be the only unit agreement which provides for a royalty rate of twenty percent, numerous oil and gas leases issued during the time period in which the Milne Point Unit Agreement was approved also provide for a twenty percent royalty rate. No special provision was made by statute, regulation, agreement, or lease to treat differently applications for royalty reduction on leases bearing a twenty percent royalty rate from applications for royalty reduction on leases bearing a 12.5 percent royalty rate.

Fourth, even if paragraph 18(h)(8) of the Milne Point Unit Agreement governed Conoco's application (AS 38.05.180(j) and (p) having no force or effect), paragraph 18(h)(8): (a) makes relief discretionary, and (b) requires a clear showing by Conoco that the revenue from all oil and gas produced from the field is insufficient to produce a reasonable rate of return on Conoco's total investment in the field. Following the reasoning set forth in the Recommended Decision, I find that: (a) it would be an abuse of my discretion to grant the royalty reduction requested because it is not in the public interest, and (b) Conoco has failed to make

a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field.

Fifth, AS 38.05.180(j) is not being applied retroactively. It was incorporated by reference in the Milne Point Unit Agreement. It is being applied to an application submitted after the statute's effective date. And it did not materially and adversely impact Conoco such as to constitute an impairment of contract.

Sixth, footnote 15 of Conoco's comments indicates that the Recommended Decision used as a reasonable rate of return "current T-Bill rates, which are ... 2.4% in real terms." In fact, the Recommended Decision used as a reasonable rate of return the average of the Treasury Bill rates for the life of the Milne Point Unit (1980-1989), which average rate approximates six percent per annum in real terms.

Seventh, when Conoco submitted an application for royalty reduction in 1985, it requested relief under AS 38.05.180(p). AS 38.05.180(p) does not require two years production before relief can be granted. However, Conoco's application was also burdened by the requirements of paragraph 18(h)(8) of the Milne Point Unit Agreement. That paragraph requires two years of production before royalty reduction can be granted. Conoco had not produced for two years from the Milne Point Unit until February 1990. Therefore, if for no other reason, Conoco's 1985 application had to be denied because Conoco had not then produced for two years.

Eighth, public utility law and oil and gas law can be distinguished on grounds other than the costs of capital for utilities and oil and gas producers. A public utility often has a single profit center; if its economic return is insufficient, its entire operation may cease. For that reason, public utility law seeks to guarantee a return adequate to assure continuing services from what is often the sole source for those services. Conversely, the major oil producers, including Conoco, have multiple profit centers. Should Conoco fail to obtain what it considers to be an adequate return on a single profit center--such as the Milne Point Unit--Conoco's other more-profitable ventures virtually assure Conoco's continued existence. But even if Conoco failed to survive, the public's supply of oil and gas is not dependent on a single producer. Therefore, neither this State's oil and gas leases nor the royalty reduction statutes need guarantee an oil producer a specific rate of return, or any return at all. I find that no guarantee of a rate of return was intended by the legislative or executive branches of this State's government.

In addition to clarifying the foregoing matters, I hereby supplement the Recommended Decision's public interest finding. Contrary to the assertions of Conoco, the public interest finding did not simply weigh cash gains and losses to the state government. The Recommended Decision determined that lost revenues to the state government would be approximately four times greater than the sum of additional royalties to the state government plus the total

value of the increase in production assured by royalty reduction.² The Recommended Decision also gave weight to additional, though speculative, production which may result from the royalty reduction. However, the Recommended Decision did not specifically or fully address certain feasible benefits of royalty reduction, probably due to their speculative and minute nature. These benefits include the following:

First, if future seismic acquisition and interpretation supports Conoco's current geologic mapping, and the State reduces its royalty to five percent, Conoco will drill two additional production wells which, based on Conoco's expectations, would produce approximately 3 million additional barrels of oil (chance factor times estimated reserves in the two largest fault blocks). This places the maximum possible additional benefit produced by the royalty reduction at 4.2 million barrels (3 million barrels of new

² The Recommended Decision, at page 13, states:

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is \$12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$64,000,000 in royalties on oil produced during the next twenty-two years, and gain \$720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at \$14,400,000.

Assuming that the average wellhead value is \$22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$109,000,000 in royalties on oil produced during the next twenty-two years, and gain \$1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at \$26,400,000.

reserves plus 1.2 million barrels due to three extra years of production). The royalty value to the State of the speculative additional 3 million barrels of oil at a \$22 per barrel well head value is approximately \$3.3 million. Consequently, if royalty reduction was granted, the State would forego \$109 million in royalties to gain up to \$4.5 million in royalties from additional production.

Second, royalty reduction is virtually certain to increase production by 1.2 million barrels, and may increase it by an additional 3 million barrels. The Trans-Alaska Pipeline transports 2 million barrel per day. One million, two-hundred thousand barrels would fill the line for 14.4 hours. Three million barrels would fill the line for 36 hours. The sum of the two volumes would fill the line for just 50.4 hours.

Third, additional production from the Milne Point Unit could mean additional jobs. Based on Conoco's statement that it may be able to increase production in the event of a royalty reduction by drilling two additional wells, I estimate that no more than thirty additional workers would be employed for a period no greater than one month.

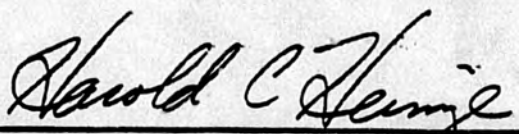
In weighing the costs and benefits of royalty reduction, foregone royalties, additional royalties, and additional production can be quantified, at least in a relative sense. Assigning dollar values to pipeline fill and additional jobs is more difficult. Yet clearly these benefits are insufficient to overcome the phenomenal costs of granting the royalty reduction requested by Conoco.

Therefore, even after considering benefits not quantified or expressly addressed in the Recommended Decision, I conclude that it is not in the public interest to grant the royalty reduction requested by Conoco.

Subject to the foregoing, the Recommended Decision on Conoco's application for royalty reduction for the Milne Point Unit is hereby adopted as the Final Decision of the Department of Natural Resources.

STATE OF ALASKA, DEPARTMENT OF
NATURAL RESOURCES

Dated: 4/21/91


Harold C. Heinze, Commissioner

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

To: Harold C. Heinze
Commissioner

Date: December 28, 1990

Phone: 907/762-2588

From: Mark Myers
Geologist

Subject: **Recommended Decision**
and Finding for Conoco's
Royalty Reduction
Application, Milne Point
Field

Under my delegation as the department hearing officer, I am enclosing the recommendation and finding concerning Conoco's application for a royalty reduction from 20% to 5% for the Milne Point Field. As requested, in your conversation with Jim Eason, I have not enclosed Appendix 1 which contains confidential financial data furnished by Conoco. Appendix 1 is available at the Division of Oil and Gas should you wish to review this data and technical analysis of Conoco's request.

I will be on personal leave from December 31 through January 4. Please feel free to contact me at your convenience, should you have any questions.

Enclosure

1

**RECOMMENDED DECISION OF THE COMMISSIONER OF
NATURAL RESOURCES REGARDING THE CONOCO
APPLICATION FOR ROYALTY REDUCTION ON ADL 47433,
47434, 47437, 47438, AND 28231 (KUPARUK
PARTICIPATING AREA: MILNE POINT UNIT).**

12/28/90

Finding and Recommendation

Conoco has applied for a reduction of its royalty from 20 percent to five percent on Kuparuk Formation oil produced from the Milne Point Unit. Given the short history of the field, the information provided in Conoco's application and its public comments on the application fail to: (1) provide a clear showing that its revenue over time will not allow for a reasonable rate of return; (2) demonstrate with any certainty that the requested reduction will significantly prolong the life of the field; or (3) demonstrate that the requested reduction would secure the proper protection of the public interest.

A clear showing of a failure to achieve a pre-determined rate of return over time requires accurate forecasting of oil prices over nearly two decades, as well as a clearer understanding of the potential total production from Milne Point, both with and without royalty reduction, than is currently available. The difficulty of reliably quantifying the latter is demonstrated by Conoco's reported decision to proceed shortly with Schrader Bluff production with the goal of ultimately tripling average daily production from the unit. On its face, it is difficult to argue the need for royalty relief at this time for a field which pays no severance tax, and for which the economics will be dramatically altered in the very near future by the operator's decision to pursue development of these shallow oil sands.

You have the discretion to approve a royalty reduction when it is determined to be in the state's best interest. However, our analysis of the potential benefits which may be gained years hence from the forbearance of substantial state royalties for the next twenty years or so, does not

appear to support such a finding in Conoco's case. For the reasons discussed more fully both below in the accompanying confidential Appendix 1, I recommend that you deny Conoco's application on these bases.

The department's analysis of Conoco's application clearly illustrates the need for a policy that limits royalty relief to those instances where sufficient objective factual data, including production revenues and development expenses, are available to establish that the reduction of the state's royalty share will both prolong production and result in benefits which are demonstrably in the state's interest. In addition to maintaining a continuous, though reduced, royalty stream, those benefits could include continued employment, additional capital investments in wells and production facilities (to increase the total recovery of oil from the field) and other factors.

Although Conoco's application fails to make a clear showing of its inability to achieve a reasonable rate of return over time or of being in the state's best interest, our review of its application did point out several concerns common to any application for royalty reduction under the existing statutes. These include defining "reasonable rate of return" consistently and objectively for royalty reduction purposes, and structuring any reduction so as to be effective in achieving the desired results without unduly diminishing the state's royalty interest.

Based upon our analysis and using Conoco's application as an example, I recommend an alternative approach from that advocated by Conoco for setting a reasonable rate of return, and provide documentation to support the use of such a standard for evaluating future applications. If you agree with the use of the rate of return test which is suggested, I recommend that the division prepare appropriate draft regulations and notice them for public comment and hearing so that future applicants who may be affected have the opportunity to comment on the draft regulations.

I. Background and Introduction

Conoco Inc. has applied for a reduction of the State of Alaska's royalty interest in oil and gas production from the Kuparuk River Participating Area of the Milne Point Unit. In its application, Conoco requests that the State's royalty interest in its production from the Kuparuk Formation only, underlying ADLs 47433, 47434, 47437, 47438, and 28231, be reduced from 20% to 5%. Conoco has not requested a royalty reduction for production from the Schrader Bluff Formation, which lies above the Kuparuk Formation throughout much of the Milne Point Unit.

Conoco submitted its formal application for royalty reduction in February 1990. However, the application was not determined to be substantially complete until July 1990. As provided for under 11 AAC 83.185, a public hearing on the application was conducted by the department on August 28, 1990. Conoco continued to submit documents in support of its application through October 9, 1990. Conoco's application has been evaluated under, alternatively, AS 38.05.180(p), AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, and AS 38.05.180(j), as amended in 1990 by HB 128, effective September 12, 1990.

Two key terms used in these statutes need to be clearly defined in order to make a royalty reduction determination. These terms are discussed in Parts II, III, and IV. Part III defines "field," as used in the royalty reduction context. Part IV analyzes what constitutes a "reasonable rate of return." Part V specifies why a decision to grant royalty relief is discretionary, not mandatory. Parts VI, VII, and VIII address each of the three statutory provisions listed above, as they apply to Conoco's application. Part IX refutes Conoco's assertion that Paragraph 18(h)(8) of the Milne Point Unit Agreement controls disposition of its application for a royalty reduction. Finally, this document concludes with a brief summary of this finding and recommendation.

This document is accompanied by Appendix 1, an economic analysis of rates of return, the cost of capital, Conoco's confidential financial data, and the costs to the state of a royalty reduction as proposed by Conoco in this instance. Appendix 1 was prepared by Ed Phillips, Petroleum Economist (retired) for the Division of

Oil and Gas. Although Appendix 1 supports the conclusions reached herein, it cannot be part of the public record of this recommended decision. It must remain confidential due to its extensive references to Conoco's proprietary information and data which are entitled to confidentiality under state statutes.

II. Definitions

Two key terms used in the statutes need to be clearly defined in order to make a royalty reduction determination. These terms are reasonable rate of return, and field. Since these terms lack statutory definitions for the purposes of royalty reduction, and since no previous requests for royalty reduction have been granted, these terms are examined with respect to this application. In its August 27, 1990 supplemental brief Conoco attempted to define the terms reasonable rate of return and field and presented arguments why the department should be bound by the definitions in its review of Conoco's application. The following two sections will explain why, in my opinion, Conoco's proposed definitions are inappropriate and must be rejected. Additionally, these sections will provide alternative definitions of these terms and demonstrate why these definitions are appropriate for royalty reduction analyses.

III. Definition of a Field

AS 38.05.180(j), before and after amendment by H.B. 128, and paragraph 18(h)(8) of the Milne Point Unit Agreement restrict royalty relief to instances in which the "field" would not otherwise produce a reasonable rate of return. AS 38.05.180(j) before amendment also requires that the relief prolong "field" life. AS 38.05.180(j) after amendment by H.B. 128 requires that either the relief be necessary to prolong "field" life or restore shut-in production. Neither the royalty reduction statutes or the Unit Agreement define "field."

Conoco, in its supplemental brief submitted on August 27, 1990, stated its belief that, for the purpose of royalty reduction, the Milne Point leases contain two separate oil fields, the Kuparuk River and Schrader Bluff "Fields." It based its argument on the fact that the two oil pools are vertically separated, have different reservoir properties, and will require

different production techniques. Additionally, Conoco's brief states that the definition it offers is identical to the definition of "field" used in Texas oil and gas law. Conoco's argument for considering the Schrader Bluff and Kuparuk River oil pools as separate fields is summarized by the following statement: "Geologically distinct fields will also be economically distinct, and therefore of little utility in assessing the economics of each other." (Supplemental Brief of Conoco and Oxy USA Inc. p.25).

To support its interpretation of the definition of "field" Conoco referenced *Wotton v. Bush*, 261 P.2d 256 (Cal. 1953), in which for the purpose of well spacing requirements, an administrative officer of the California Division of Oil and Gas testified that "a field has come to be considered as that expanded area from the region of initial production to the limits of productivity in all lateral directions; and that within a given field there was no structural connection or drainage to or from other fields." It should also be noted that unlike Milne Point, the fields in the *Wotton* case were geographically (laterally) separated and not at different depths on the same leases. The *Wotton* case dealt with the issue of well spacing requirements. Appropriate well spacing is ideally determined by internal reservoir properties including porosity, permeability, heterogeneity, viscosity of oil, reservoir thickness, reservoir pressure, fluid contacts, and other factors. These properties are certainly unique to each pool and/or reservoir and often vary within the same pool or reservoir. A definition of "field" that is applicable for determining production rates, well spacing, participating areas, internal company development plans, tax credit for enhanced oil recovery, etc. may not be applicable or even appropriate to royalty reduction. This is the case with the definition proposed by Conoco.

Conoco argues that its definition is consistent with that used by industry. However, this argument is not persuasive since there is no consistent use of the term "field" within industry. For example, the Kuparuk River Formation within the Kuparuk River Oil Field consists of two separate reservoir intervals, the A and C sands of different geologic age (Valanginian vs. Hauterivian). Additionally, the sands are vertically separated by a major regional unconformity, were deposited in different

6/

depositional settings, and have very different reservoir properties. In spite of these different properties neither industry nor the State differentiates these producing intervals when they refer to the Kuparuk River Oil Field.

For the purpose of royalty reduction, the department must define "field" in a matter that: (1) is consistent with the intent of the royalty reduction statutes, regulations, and, to the extent feasible, the Milne Point Unit Agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

A royalty reduction application under AS 38.05.180(j) must comply with 11 AAC 83.185, which requires the application to:

... (2) state location and status of all past and present activities on the lease; (3) include a detailed report of all production during the six months preceding the filing of the application; (4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease.

(Emphasis added). This regulation evidences the department's interpretation of "field" as clearly referring to all reservoirs underlying the lease.

This interpretation is consistent with earlier comments in a October 9, 1984 letter to Conoco from Division of Oil and Gas Director Kay Brown in which she stated, "the division has no statutory definition of 'field'..." and listed three possible geologic definitions of "field." "Field may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs...."

Further support for the department's interpretation of "field" comes from the definition of "field" used by another state regulatory agency, the Alaska Oil and Gas Conservation Commission (AOGCC). While AOGCC's

definition of "field" does not govern an application for royalty reduction, it is indicative of a definition accepted by industry in some settings. For the AOGCC, "field" is defined by AS 31.05.170(5), which states:

"field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground reservoir containing oil and gas; and the words "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" unlike "pool" may relate to two or more pools...

For the purpose of royalty reduction requests, the department defines "field" as encompassing the lateral limits of productivity of all reservoirs or pools within the Milne Point Unit regardless of vertical stratification of reservoirs or pools underlying a lease or leases. This definition meets the standards set out earlier: (1) is consistent with the intent of the royalty reduction statutes, regulations, and to the extent feasible, the Milne Point Unit agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

This definition allows the department to consider all the relevant information with regard to royalty reduction. Commonality of production and transportation facilities and well bores, as well as shared information and economy of scale provided by having multiple stacked reservoirs under a single lease are important factors in the development of an oil field. Not only do multiple stacked reservoirs have lower development costs, but their development also entails lower risk wells. For example, wells can be plugged back and produced from the shallower horizon, if the deeper horizon is not produced due to faulting, lack of net pay, well bore damage, depletion or other factors. The department's definition of "field" is similar to that used by AOGCC in that it considers multiple vertically separated pools or reservoirs underlying the same lease or leases a single "field."

Utilizing a definition that encompasses all reservoirs or pools within the Milne Point Unit also helps minimize the incentive for the operator and lessees to manipulate production and/or costs from individual reservoirs within the Unit for the purposes of affecting royalty reduction applications.

Note that the department's definition does not prohibit the commissioner from granting selective relief to individual pools or reservoirs, or even individual leases. In this case, the ability to do so is clearly stated by the Milne Point Unit Agreement and not prohibited by statute.

IV. Definition of Reasonable Rate of Return

Similarly, regardless of whether one is guided by State law or the Milne Point Unit Agreement, there is the potential for serious disagreement between the applicant and the department regarding what constitutes "a reasonable rate of return" for the purpose of evaluating a royalty reduction request. Without providing objective standards, both AS 38.05.180(j) and the Milne Point Unit Agreement leave it up to the commissioner to define a reasonable rate of return for royalty reduction purposes. Against this backdrop, the department has an obligation to adopt a standard that is objective and which may be applied consistently without regard to the vagaries of the financial planning standards of individual companies. Furthermore, the standard should provide a positive real rate of return (more than inflation), yet not allow for excessive profit at the expense of the state's royalty share.

Conoco has argued in its August 27, 1990 supplemental brief and in testimony at the public hearing, that, at a minimum, a reasonable rate of return, for royalty reduction, should be defined as the cost of capital to the company plus a marginal profit. There are obvious problems with this standard. First of all, such a standard would vary widely from company to company. Of the eight major North Slope producers examined, Conoco had the highest cost of capital at a nominal rate of 12.75%. Based upon information available to the department, other North Slope producers' cost of capital ranged from a low of 9.26% (Oxy) to a high of 10.26% (ARCO). Additionally, proprietary financial data of this sort are generally

not directly available to the public, rates are difficult to monitor over time, and many projects are internally financed by the companies.

Thus, defining a reasonable rate of return standard as the individual firm's cost of capital is not acceptable since it treats every firm differently. Such a standard would provide a different level of relief based upon the company, regardless of the field. To protect the state's interest, royalty relief should be based on the economics of the field and not on a company's real or perceived internal financial characteristics. Further, the standard should be impartially applicable to all lessees. A reasonable rate of return that is independent of the particular company financing involved should be adopted to avoid possible manipulation of in-house economics simply for royalty reduction purposes.

In its August 27, 1990 supplemental brief, Conoco cites a number of public utilities law cases in support of its proposed definition of rate of return. These cases are intended to demonstrate examples where the most strict standard for a reasonable rate of return is the cost of capital. However, for royalty reduction purposes, these are invalid analogs. A public utility is granted a rather generous (but capped) rate of return since it is regulated and at the same time must compete with unregulated firms in the capital market. Also, a public utility does not have an opportunity to make large profits in other settings, as does a large, privately owned integrated oil company such as Conoco. Neither Conoco's prices nor its costs are regulated by a public agency therefore, Conoco has no regulated limits on its potential profitability.

It is the potential for large profits that allows Conoco, or any other oil and gas lessee for that matter, to take the risks inherent in wildcat exploration and oil field development. This provides a freedom of operation not granted to a public utility. It is therefore only proper that a more conservative standard for rate of return be applied to Conoco, and other lessees, in determining whether, and to what extent, a reduction in the state's royalty share of production is appropriate. When all the arguments are stripped away, the stated purposes of the royalty reduction statutes are to prolong the economic life of the field and protect the public interest, not

to guarantee the state's lessees a minimum rate of return on every field which they choose to develop.

Standards other than those suggested by Conoco are available to define a reasonable rate of return. For example, the economic yardstick used by the United States Geologic Survey and the U.S. Department of Energy in recent studies has been an after-tax rate of return of 8%. Referring to the development of North Slope reserves in *Economics and the National Oil and Gas Assessment, The Case of Onshore Northern Alaska* (In press Attanasi, Bird, and Mast) the authors state "Fields were considered commercially developable if a discounted cash flow analysis showed that an after-tax return of 8 percent could be achieved. At the time of the assessment, the 8 percent hurdle rate was being used by the U.S. Department of Energy's Energy Information Administration in the national energy base case forecasts (Jon Rasmussen, Energy Information Administration, oral communication)."

Another potential yardstick for defining a reasonable rate of return is the standard used by the State of Alaska Department of Revenue (DOR) in determining reasonable shipping rates for North Slope crude for the purpose of calculating severance tax obligations. Shippers are allowed the Gross National Product deflator (GNPd) plus two percentage points return to capital as allowable expenses (profits). For the 1980-1989 period, the GNPd fell short of the 90 day Treasury bill rate by 4.4 percentage points. Otherwise stated, DOR has allowed, as a reasonable rate of return, a rate which is, on average, 2.4 percentage points less than the 90 day Treasury bill rate.

The standard which I recommend the department choose to define a "reasonable rate of return" for the purposes of this application is the rate of return for a 90 day Treasury Bill. The basis for this recommendation is more fully set out in the text of Appendix 1. For the period of 1980-1989 the real rate of return for the 90 day bill was approximately six percent. This standard compares favorably with other potential standards examined by the department.

V. Discretionary Nature of Royalty Reduction

A well established rule of interpretation specifies that "may" refers to discretionary action, while "shall" dictates mandatory action. Similarly, "may not" constitutes a mandatory prohibition.

AS 38.05.180(p) states the commissioner "may ... change ... royalty requirements" Paragraph 18(h)(8) of the Milne Point Unit Agreement provides that the State "may reduce Lessee's obligation to pay royalty" Thus, both AS 38.05.180(p) and paragraph 18(h)(8) of the Milne Point Unit Agreement permit royalty reductions, but they do not mandate royalty reductions, except where a denial of a royalty reduction would be arbitrary or unreasonable.

AS 38.05.180(j), both before and after amendment by HB 128, mandates promulgation of regulations governing applications for royalty reduction: "the commissioner shall adopt regulations" However, the regulations are "to allow reduction of royalty" The word "allow," like "may," is permissive, not mandatory. AS 38.05.180(j), both before and after amendment by HB 128, then uses mandatory language to specify one instance in which royalty reduction is not allowed: "The commissioner may not grant a reduction of royalty" unless the applicant has made a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field. In short, while AS 38.05.180(j) contains some compulsory directives, it also permits denial of an application where not unreasonable or arbitrary to do so.

VI. Evaluation of Application Under AS 38.05.180(p)

AS 38.05.180(p) states:

To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation

of the pool, field or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest.

(Emphasis added).

Conoco's application, as initially submitted, represented that the Milne Point Unit Kuparuk Formation had an expected field life of twenty-five years, three years of which have almost elapsed. The original application did not indicate that the field life would be lengthened, or more oil produced, should Conoco be granted the royalty relief requested. Subsequently, Conoco amended its application, to clarify that if the State reduced its royalty to 5%, Conoco would produce 1.2 million barrels more than it would otherwise produce in the three years following the first twenty-five years of production.

In evaluating Conoco's application, the department must determine whether the public interest would best be served by the State's receipt of a 20% royalty over a remaining field life of twenty-two years, or by the State's receipt of a 5% royalty over a remaining field life of twenty-five years and the production of an additional 1.2 million barrels of oil twenty-two to twenty-five years from now. This determination cannot be made without reference to the wellhead value of Milne Point oil.

It is impossible to accurately calculate the wellhead value of production occurring over the next twenty-two to twenty-five years. The impossibility of the task is exemplified by the wide range of values for oil produced from the Kuparuk Formation in the Milne Point Unit in 1990 alone, when the reported wellhead value tripled between July and September. However, the department is able to model the effects in a gross sense by selecting a low estimated average value and a high estimated average value, then calculating the costs and benefits of granting the requested royalty reduction should values approaching either of these extremes prove accurate.

In this analysis, the department selected a low average wellhead value of \$12 per barrel and a high average wellhead value of \$22. These wellhead values were chosen to represent possible average wellhead values for the entire life of the field. These wellhead values roughly correspond with United States West Coast average prices of \$20 and \$30 per barrel, respectively.

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is \$12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$64,000,000 in royalties on oil produced during the next twenty-two years, and gain \$720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at \$14,400,000.

Assuming that the average wellhead value is \$22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose \$109,000,000 in royalties on oil produced during the next twenty-two years, and gain \$1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at \$26,400,000.

Under both scenarios the cost of the royalty reduction to the State is roughly four times the combined value of the benefits, including the state's royalty share. These analyses were conducted in constant 1989 dollars. Obviously, had they been done in present value terms, the disparity between costs and benefits would have been even greater.

But there are other benefits which may be obtained by reducing the royalty rate to 5%. By letters dated May 16 and October 9, 1990, Conoco committed to expand its 3-D seismic program, and, dependent on the outcome of the seismic program, possibly drill two additional wells to evaluate three regions of the Kuparuk Formation within the Milne Point Field. These wells would be targeted to delineate the resource potential of several small fault blocks and/or the down-dip limit of the field. Conoco first termed the magnitude of reserve additions attributable to these operations as "totally speculative." Subsequently, Conoco

provided reserve estimates for one of the three regions and risk factors for all three regions. Based on the relatively low reserve estimate, coupled with the risk factor, the conditional nature of the commitment to drill, and ownership interests of other parties in the reserves, the department concludes that the potential incremental benefits of royalty reduction are insufficient to tip the scales in favor of granting the reduction requested.

Based on the extraordinary value of lost royalties, the modest benefit of a 1.2 million barrel increase in production, and the highly speculative benefits of Conoco's commitment to additional exploration and development activities, it is extremely difficult to make a finding that granting the royalty reduction which Conoco requests is either necessary or proper to secure the proper protection of the public interest.

VII. Evaluation of Application Under AS 38.05.180(j). Prior to Amendment By HB 128 in 1990

AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, stated:

AS 38.05.180(j) "To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field."

(Emphasis added).

As with AS 38.05.180(p), relief under AS 38.05.180(j) is discretionary. However, the department should not exercise its discretion in favor of royalty reduction unless the reduction is in the public interest. For the reasons discussed in Part VI, above, granting the royalty reduction as requested by Conoco is not in the public interest.

To qualify for relief under AS 38.05.180(j), an applicant must establish that the relief requested: (1) follows two years initial production from the field; (2) will prolong the economic life of the field; (3) will compensate for increasing costs in the later stages of production decline; and (4) is necessary to produce a reasonable rate of return on the applicant's total investment in the field.

Conoco submitted its application for royalty reduction immediately following two years of cumulative production from the Kuparuk Formation of the Milne Point field; therefore, the requirement of two years initial production from the field has been met. However, Conoco has not established that the requested royalty reduction will significantly prolong the economic life of the field. While the field life might be extended by three years, more than twenty years in the future, the number of years added is not relevant—the number of additional barrels recovered is. Conoco's unconditional commitment to increased production is limited to 1.2 million barrels. This volume represents less than 2% of the estimated production for the Kuparuk Formation, and an even lesser percentage of estimated production for the Milne Point field. Given the cost to the State of the royalty reduction requested, the amount of potential new production 20+ years hence is almost inconsequential in both absolute and relative terms.

Having failed the second part of a four part test for royalty reduction under AS 38.05.180(j), it is unnecessary to examine elements three and four. However, brief mention of the two remaining elements is appropriate. AS 38.05.180(j) restricts royalty reduction to instances in which it will compensate for increasing costs in the later stages of production decline. First, the department has received no information that would indicate the Milne Point field is in the later stages of production decline. To the contrary, Conoco has announced plans to develop the Schrader Bluff Formation within the Milne Point with the ultimate goal of at least doubling production. Second, the department interprets this requirement as limiting the amount of relief which may be granted to that amount necessary to offset the increase in costs. It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the later stages of production decline. Given the volatility of future oil prices and the remoteness of late-stage costs, the

department should not conclude that this standard would be met by granting the requested royalty reduction at this time.

Finally, AS 38.05.180(j) requires the applicant to make a clear showing that the revenue generated by the field is insufficient to produce a reasonable rate of return on the total investment in the field. A clear showing requires evidence which is precise, explicit, and which directly establishes the point. It is very difficult, if not impossible, to provide such evidence here, since the Milne Point field is in the very early stages of production. Use of estimated value, production, and cost data for the remaining twenty-two to twenty-five year life of the field adds a high level of uncertainty to determining the long-term validity of any purported "need" for Conoco's royalty reduction. Particularly disturbing is the unreliability inherent in estimating the value of oil to be produced over the next twenty-two to twenty-five years. As mentioned earlier, this unreliability is dramatically underscored by the tripling of reported wellhead values from the Milne Point Unit between July and September 1990.

Estimating revenue from future production is further complicated by a lack of knowledge regarding the potential volume and value of future production from other pools in the Milne Point field, such as the Schrader Bluff Formation, as well as by price and technology sensitive enhanced oil recovery techniques which may significantly increase total production from all reservoirs or pools within the Milne Point field.

On the other hand, since much of the major field facility development has already occurred, the cost estimates for the remaining field life are easier to approximate. According to the data submitted by Conoco on June 13, 1990, about 87% of the capital investment in field facilities has been completed, leaving only relatively minor capital investment expenses to be estimated. This, however, does not include the costs associated with Schrader Bluff development and production.

In short, the department may reasonably conclude it impossible to make a clear showing that the revenue generated by the Milne Point field over its entire life will be insufficient to produce a reasonable rate of return on the total investment in the field when but a small fraction of the minimum estimated field life has transpired.

In conclusion, Conoco's application should not be granted as requested under AS 38.05.180(j) (as it existed before amended by HB 128). Conoco has not established that reducing the royalty rate on the Kuparuk Formation from 20% to 5% would significantly prolong the life of the Milne Point field. A minimal extension of the field at a very high cost to the State is not in the public interest. Furthermore, the uncertainties inherent in estimating revenue and costs for the next twenty-two to twenty-five years allow the commissioner to conclude that Conoco cannot adequately show either the magnitude of increasing costs in the later stages of production decline or total field life rate of return.

**VIII. Evaluation of Application Under AS 38.05.180(j). As Amended
By HB 128 in 1990**

AS 38.05.180(j) was amended by HB 128, effective September 12, 1990. It now reads:

To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible, the commissioner shall adopt regulations to allow reduction of royalty on leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way to protect the state's interest, including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that the state has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee, and send copies of the finding to all members of the legislature.

(Emphasis added).

As with AS 38.05.180(p), and AS 38.05.180(j) prior to its amendment by HB 128, relief under the amended standard is discretionary. The department, however, should not exercise its discretion in favor of royalty reduction unless the reduction is demonstrated to be in the public interest. For the reasons discussed in Part VI, above, granting royalty reduction as requested by Conoco, in this instance is not in the public interest.

Under AS 38.05.180(j) as amended by HB 128, royalty relief cannot be granted unless it will either prolong the economic life of an oil and gas field or reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible. The royalty reduction requested by Conoco will not substantially prolong the economic life of the Kuparuk Formation or Milne Point field for the reasons discussed in Part VII, above. Nor is the Kuparuk Formation shut-in as it was for several months before Conoco submitted its application. Therefore, Conoco's application fails these alternative requirements of AS 38.05.180(j), as amended by HB 128.

As 38.05.180(j), as amended, also retains the requirement of a clear showing that revenue from the field is insufficient to produce a reasonable rate of return on total field investment. The department's analysis of this requirement is the same under both the former AS 38.05.180(j) and its current amended version. (See Part VII, above).

The 1990 amendment to AS 38.05.180(j) specifies that an application for royalty reduction cannot be approved unless the commissioner makes a written finding that the State has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the applicant. Due to volatile oil prices, risks inherent in oil and gas production, and uncertain future costs, the department cannot find that the State will obtain its maximum possible economic return without providing for the recapture of foregone royalties in the event a lessee ultimately achieves more than a predetermined reasonable rate of return. However, in this instance the department need not craft a limited or conditional royalty relief, since the royalty relief requested is inappropriate for other reasons, as discussed above.

IX. Milne Point Unit Agreement. Paragraph 18(h)(8)

Conoco argues in its August 27, 1990 supplemental brief that paragraph 18(h)(8) of the Milne Point Unit Agreement governs its application for royalty reduction; and that AS 38.05.180 (p) and (j) apply only to the extent that they are not inconsistent with the unit agreement. Paragraph 18(h)(8) states:

Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

Conoco's argument that paragraph 18(h)(8) prevails where inconsistent with AS 38.05.180(p) or (j) appears to be based on an incomplete reading of paragraph 1 of the Unit Agreement, which states:

The Alaska Land Act ... and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska are hereby accepted and made a part of this agreement.

(Emphasis added). Conoco chooses to ignore that all statutes not inconsistent with the laws of the State of Alaska are incorporated by reference in the Unit Agreement. Since the statutes are the laws of the State of Alaska, they cannot be inconsistent with the laws of the State of Alaska (except to the extent that one or more statutes are contrary to the United States or Alaska constitution). Therefore, AS 38.05180(j) and (p) are incorporated by reference in the Unit Agreement, and are thus every bit as much a part of the Unit Agreement as is paragraph 18(h)(8).

In any case, a state agency is without authority to enter into an agreement in conflict with applicable statutes. Thus, even without an explicit incorporation of

Alaska's statutes by reference in Paragraph 1 of the Milne Point Unit Agreement, the statutes control when in conflict with the Unit Agreement.

X. Summary

In this instance, I have recommended that the requested royalty reduction should be denied under AS 38.05.180(p), (j), and (j), as amended by H.B. 128 since the department concludes that Conoco has failed to demonstrate:

- (1) that granting the requested royalty relief will be in the public interest;
- (2) that reducing the royalty from 20% to 5% will significantly prolong the economic life of the field; and
- (3) a clear showing that its revenue from oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Conoco's total investment in the field.

The statutes and regulations do not discuss the quantity or quality of data needed to demonstrate a clear showing (though, obviously, "clear showing" is a high standard) that Conoco's revenue from the field is insufficient to produce a reasonable rate of return with respect to its total investment in the field. Similarly, the statutes and regulations do not list precisely the quantity or quality of data needed to demonstrate that the economic life of the field will be significantly prolonged by a royalty reduction. These determinations must be made by the commissioner based on the discretionary power granted by the statutes, department regulations, and the Milne Point Unit Agreement. However, it becomes apparent that, especially in the case of a field such as Milne Point, with only a few years of production history, determining the long term profitability of the field with any certainty is virtually impossible.

In order to thoroughly evaluate Conoco's application, an extensive financial, economic, and technical analysis was completed by the department. While I recommend that the department deny the application, this analysis provides a groundwork for evaluating future royalty reduction requests since this was the first request completely processed by the department.

Even though it is recommended that Conoco's application for a royalty reduction to 5% be denied, the division felt obligated to carefully analyze the data submitted to determine if an alternative approach for royalty reduction could be developed which would meet the statutory requirements. Among the possibilities examined were a sliding scale royalty based on wellhead value, short term relief, relief down to a floor of 12.5% and combinations of these three methodologies. These limited and/or conditional alternatives to a complete denial were determined to be unacceptable since in all cases examined, even ignoring Conoco's failure to make a clear showing, the estimated return to the state and public was substantially less than the estimated revenue lost by the state in forgone royalty. Therefore, even a limited or conditional royalty does not appear to be in the public interest at this time.

ENCLOSURE 4

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

CERTIFIED MAIL — Return Receipt Requested

April 17, 1991

Mr. Richard E. Foppiano
Oxy USA, Inc.
Box 50250
Midland, TX 79710

Dear Mr. Foppiano:

The review process of the Conoco and Oxy USA applications for royalty reduction from 20 percent to 5 percent on the Milne Point Unit Kuparuk production has concluded. Based on the failure to show any net public benefit, I am denying these applications for royalty reduction.

The extensive records on these applications indicate that the profitability of the Milne Point Unit has not achieved the companies' desired level. However, the State as a royalty owner has no authority or responsibility to guarantee the success or profitability of a leasee's investment decisions.

The State of Alaska has given this marginal oilfield significant help by severance tax relief; a further grant of up to \$100 million through royalty relief is not warranted. The State as a royalty owner will not share in the risk of the companies' decisions.

However, there are a couple circumstances in which it may be in the public interest for the royalty owner to reduce its share of the current production to gain a long-term payback benefit.

At some point in an oilfield's later life the production revenue (excluding the royalty barrels) will not be sufficient to cover all the cash costs and operations may cease absent royalty reduction. This is not the current situation in the Milne Point Unit where production revenues from the Kuparuk formation are at the \$4-to-5-million per month level compared to operating costs of \$1-to-1.5 million per month. This circumstance of reaching the "economic limit" of production operations is projected by the companies to occur in a couple decades and can be considered at that time.

A second circumstance in which a royalty owner may choose to help the producer is to encourage further investment that has a direct net benefit to the state. In this situation, the data does not indicate that increasing profitability through a royalty

Mr. Richard Foppiano

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April 17, 1991

reduction would result in an incremental prospective investment that could have an incremental direct benefit to the State large enough to offset the royalty loss. While this circumstance may occur in the future, the current submittal asks the State to give up over 5 million barrels of royalty oil for a potential reward replacing only a few percent of that loss.

Sincerely,

Harold C. Heinze
Harold C. Heinze
Commissioner

cc: John Tillinghast, Attorney
Birch, Horton, Bittner & Cherot
James Eason, Director
Division of Oil and Gas

DECISION OF THE COMMISSIONER
ON OXY'S APPLICATION FOR ROYALTY REDUCTION

OXY USA, Inc. submitted an application to the State of Alaska Department of Natural Resources (DNR). That application requested that the State's royalty share of oil and gas produced from the Kuparuk River formation underlying four Milne Point leases be reduced from twenty percent to five percent.

OXY's application was analyzed by the staff of the Division of Oil and Gas. Edward Phillips, Petroleum Economist (retired), prepared a confidential economic analysis of the application. Mark Myers, Petroleum Geologist, conducted a public hearing on the application, then prepared a Recommended Decision on OXY's application.

Normally, the Commissioner of the DNR would act on a recommended decision without further input from OXY. However, OXY requested and was granted thirty days in which to comment on the Recommended Decision. OXY's comments consisted of fourteen pages of text, an affidavit, and two confidential exhibits, all of which have now been reviewed by this Commissioner.

As Commissioner, I hereby adopt the Recommended Decision as the final decision of DNR, subject to the additional findings and conclusions set forth in the remainder of this Final Decision.

In this Final Decision I do not undertake to address every alleged fact and argument raised by OXY in its final comments. Much of OXY's final comments consisted of arguments raised by Conoco in its final comments on the hearing officer's recommendation on Conoco's parallel application for royalty reduction. For

that reason, I hereby incorporate by reference my Decision on Conoco's application for royalty reduction; that Decision is also being issued on this date.

One argument unique to OXY's final comments is that I should not consider production from the Schrader Bluff formation of the Milne Point field because OXY has not made a decision to participate in Schrader Bluff development. This argument is wholly unfounded. The Schrader Bluff Participating Area was approved by this department's Division of Oil & Gas on March 29, 1991. Production has commenced from the Schrader Bluff Participating Area. OXY currently has a 2.9% interest in any production from the Schrader Bluff Participating Area. Consequently, income to OXY from Milne Point field formations other than the Kuparuk River formation is anything but speculative.

OXY's final comments also criticize this department for its failure to provide OXY with a copy of the confidential economic analysis of OXY's application. Because OXY did not provide the department with complete economic data, the department was not able to fully analyze OXY's application without resort to confidential economic data provided by the Milne Point Unit operator and OXY's co-lessee—Conoco. Until such time as Conoco authorizes release of the data necessarily relied upon by the department, I have no choice but to keep the economic analysis accompanying the Recommended Decision confidential.

Finally, OXY's comments suggest that two third-party measures of a reasonable rate of return cited by the hearing officer in his Recommended Decision both support an 8% real rate of return. In

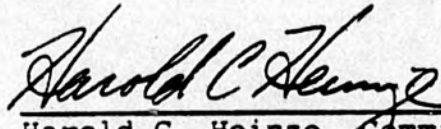
fact, only one measure supported an 8% real rate of return; the second measure supported a 3.6% real rate of return. The measure selected by the hearing officer yielded a 6% real rate of return.

Subject to the foregoing, the Recommended Decision on OXY's application for royalty reduction for the Milne Point Unit is hereby adopted as the Final Decision of the Department of Natural Resources.

STATE OF ALASKA, DEPARTMENT OF
NATURAL RESOURCES

Dated: _____

4/22/91



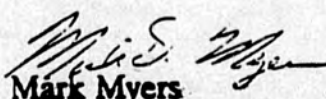
Harold C. Heinze, Commissioner

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

To: Harold C. Heinze
Commissioner

Date: March 5, 1991

From: 
Mark Myers
Petroleum Geologist

Phone: 762-2182

Subject: Recommended Decision and
Finding for Oxy USA Inc.'s
Royalty Reduction
Application, Milne Point
Field

Under my delegation as the department hearing officer, I am enclosing the recommendation and finding concerning Oxy USA Inc.'s application for a royalty reduction from 20% to 5% for the Milne Point Field.

Similar to Conoco, Oxy has requested thirty days to reply to the Recommended Decision. Please feel free to contact me at your convenience, should you have any questions.

Enclosure

038912b.mmr

Point Unit. In its application, Oxy requests that the State's royalty interest in its production from the Kuparuk Formation, underlying ADLs 47433, 47434, 47437, and 47438 be reduced from 20% to 5%. Oxy has not requested a royalty reduction for production from the Schrader Bluff Formation, which lies above the Kuparuk Formation throughout much of the Milne Point Unit. Nor, to the department's knowledge, has Oxy proposed that the overriding royalty owners reduce their royalty share of Kuparuk Formation production.

Oxy submitted its formal application for royalty reduction in June 1990. However, the application was not determined to be substantially complete until July 1990. A public hearing on the application was conducted by the department on August 28, 1990. Oxy's application has been evaluated under, alternatively, AS 38.05.180(p), AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Oxy's application was submitted, and AS 38.05.180(j), as amended in 1990 by HB 128, effective September 12, 1990.

Two key terms used in these statutes need to be clearly defined in order to make a royalty reduction determination. These terms are discussed in Parts II, III, and IV. Part III defines "field," as used in the royalty reduction context. Part IV analyzes what constitutes a "reasonable rate of return." Part V specifies why a decision to grant royalty relief is discretionary, not mandatory. Parts VI, VII, and VIII address each of the three statutory provisions listed above, as they apply to Oxy's application. Part IX refutes Oxy's assertion that Paragraph 18(h)(8) of the Milne Point Unit Agreement controls disposition of its application for a royalty reduction. Finally, this document concludes with a brief summary of this finding and recommendation.

II. Definitions

Two key terms used in the statutes need to be clearly defined in order to make a royalty reduction determination. These terms are reasonable rate of return, and field. Since these terms lack statutory definitions for the purposes of royalty reduction, and since no previous requests for royalty reduction have been granted, although a parallel request by Conoco for royalty reduction at Milne Point is pending, these terms are examined with respect to this application. In its

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August 27, 1990 supplemental brief, Oxy attempted to define the terms **reasonable rate of return** and **field** and presented arguments why the department should be bound by these definitions in its review of Oxy's application. The following two sections will explain why, in my opinion, Oxy's proposed definitions are inappropriate and must be rejected. Additionally, these sections will provide alternative definitions of these terms and demonstrate why these definitions are appropriate for royalty reduction analyses.

III. Definition of a Field

AS 38.05.180(j), before and after amendment by H.B. 128, and paragraph 18(h)(8) of the Milne Point Unit Agreement restrict royalty relief to instances in which the **"field"** would not otherwise produce a reasonable rate of return. AS 38.05.180(j) before amendment also requires that royalty relief prolong **"field"** life. AS 38.05.180(j) after amendment by H.B. 128 requires that either the relief be necessary to prolong **"field"** life or restore shut-in production. Neither the royalty reduction statutes or the Unit Agreement define **"field."**

Oxy, in its supplemental brief submitted on August 27, 1990, stated its belief that, for the purpose of royalty reduction, the Milne Point leases contain two separate oil fields, the Kuparuk River and Schrader Bluff **"Fields."** It based its argument on the fact that the two oil pools are vertically separated, have different reservoir properties, and will require different production techniques. Additionally, Oxy's brief states that the definition it offers is identical to the definition of **"field"** used in Texas oil and gas law. Oxy's argument for considering the Schrader Bluff and Kuparuk River oil pools as separate fields is summarized by the following statement: **"Geologically distinct fields will also be economically distinct, and therefore of little utility in assessing the economics of each other."** (Supplemental Brief of Conoco and Oxy USA Inc. p.25).

To support its interpretation of the definition of **"field"** Oxy referenced *Wotton v. Bush*, 261 P.2d 256 (Cal. 1953), in which for the purpose of well spacing requirements, an administrative officer of the California Division of Oil and Gas testified that **"a field has come to be considered as**

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to support such a finding in Oxy's case. For the reasons discussed more fully both below, I recommend that you deny Oxy's application on these bases.

The department's analysis of Oxy's application clearly illustrates the need for a policy that limits royalty relief to those instances where sufficient objective factual data, including production revenues and development expenses, are available to establish that the reduction of the state's royalty share will both prolong production and result in benefits which are demonstrably in the state's interest. In addition to maintaining a continuous, though reduced, royalty stream, those benefits could include continued employment or new jobs, additional capital investments in wells and production facilities (to increase the total recovery of oil from the field) and other benefits.

Although Oxy's application fails to make a clear showing of its inability to achieve a reasonable rate of return over time or of being in the state's best interest, my review of its application reconfirmed several concerns common to any application for royalty reduction under the existing statutes, as was pointed out in my recent recommendation concerning Conoco's application for royalty relief. These include defining "reasonable rate of return" consistently and objectively for royalty reduction purposes, and structuring any reduction so as to be effective in achieving the desired results without unduly diminishing the state's royalty interest.

Based upon my analysis and using Oxy's application as an example, I recommend an alternative approach from that advocated by Oxy for setting a reasonable rate of return, and provide documentation to support the use of such a standard.

I. Background and Introduction

Oxy Inc. has applied for a reduction of the State of Alaska's royalty interest in oil and gas production from the Kuparuk River Participating Area of the Milne

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**RECOMMENDED DECISION OF THE COMMISSIONER OF
NATURAL RESOURCES REGARDING THE OXY USA INC.
APPLICATION FOR ROYALTY REDUCTION ON ADL 47433,
47434, 47437, AND 47438 (KUPARUK PARTICIPATING
AREA: MILNE POINT UNIT).**

3/5/91

Finding and Recommendation

Oxy USA Inc. (Oxy) has applied for a reduction of its royalty from 20 percent to five percent on Kuparuk Formation oil produced from the Milne Point Unit. Given the short production history of the field, the information provided in Oxy's application and its public comments on the application fail to: (1) provide a clear showing that its revenue over time will not allow for a reasonable rate of return; (2) demonstrate with any certainty that the requested reduction will significantly prolong the life of the field; or (3) demonstrate that the requested reduction would secure the proper protection of the public interest.

A clear showing of a failure to achieve a ~~pre-determined rate of return~~ over time requires accurate forecasting of oil prices over nearly two decades, as well as a clearer understanding of the potential total production from Milne Point, both with and without royalty reduction, than is currently available. The difficulty of reliably quantifying the latter is demonstrated by the reported decision to proceed shortly with Schrader Bluff Formation oil production with the goal of ultimately tripling average daily oil production from the unit. On its face, it is difficult to argue the need for royalty relief at this time for a field which pays no severance tax, and for which the economics will be dramatically altered in the very near future by the operator's decision to pursue commercial development of these shallow oil sands.

You have the discretion to approve a royalty reduction when it is determined to be in the state's best interest. However, our analysis of the potential benefits which may be gained years hence from the forbearance of substantial state royalties for the next twenty years or so does not appear

that expanded area from the region of initial production to the limits of productivity in all lateral directions; and that within a given field there was no structural connection or drainage to or from other fields." It should also be noted that unlike Milne Point, the fields in the *Wotton* case were geographically (laterally) separated and not at different depths on the same leases. The *Wotton* case dealt with the issue of well spacing requirements. Appropriate well spacing is ideally determined by internal reservoir properties including porosity, permeability, heterogeneity, viscosity of oil, reservoir thickness, reservoir pressure, fluid contacts, and other factors. These properties are certainly unique to each pool and/or reservoir and often vary within the same pool or reservoir. A definition of "field" that is applicable for determining production rates, well spacing, participating areas, internal company development plans, tax credit for enhanced oil recovery, etc. may not be applicable or even appropriate to royalty reduction. This is the case with the definition proposed by Oxy.

Oxy argues that its definition is consistent with that used by industry. However, this argument is not persuasive since there is no consistent use of the term "field" within industry. For example, the Kuparuk River Formation within the Kuparuk River Oil Field consists of two separate reservoir intervals, the A and C sands of different geologic age (Valanginian vs. Hauterivian). Additionally, the sands are vertically separated by a major regional unconformity, were deposited in different depositional settings, and have very different reservoir properties. In spite of these different properties neither industry nor the State differentiates these producing intervals when they refer to the Kuparuk River Oil Field. Furthermore, another state regulatory agency, the Alaska Oil and Gas Conservation Commission (AOGCC), considers the A and C sands of the Kuparuk pool plus the vertically separated West Sak pool (Schrader Bluff Formation) as elements of the Kuparuk River Oil Field.

For the purpose of royalty reduction, the department must define "field" in a manner that: (1) is consistent with the intent of the royalty reduction statutes, regulations, and, to the extent feasible, the Milne Point Unit Agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied

impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

A royalty reduction application under AS 38.05.180(j) must comply with 11 AAC 83.185, which requires the application to:

... (2) state location and status of all past and present activities on the lease; (3) include a detailed report of all production during the six months preceding the filing of the application; (4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease;

(Emphasis added). This regulation evidences the department's interpretation of "field" as clearly referring to all reservoirs underlying the lease.

This interpretation is consistent with earlier comments in a October 9, 1984 letter to Conoco from Division of Oil and Gas Director Kay Brown in which she stated, "the division has no statutory definition of 'field'..." and listed three possible geologic definitions of "field." "Field may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs...."

Further support for the department's interpretation of "field" comes from the definition of "field" used by AOGCC. While AOGCC's definition of "field" does not govern an application for royalty reduction, it is indicative of a definition accepted by industry in some settings. For the AOGCC, "field" is defined by AS 31.05.170(5), which states:

"field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground reservoir containing oil and gas; and the words "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" unlike "pool" may relate to two or more pools...

For the purpose of royalty reduction requests, the department defines "field" as encompassing the lateral limits of productivity of all reservoirs or pools within the Milne Point Unit regardless of vertical stratification of reservoirs or pools underlying a lease or leases. This definition meets the standards set out earlier; (1) It is consistent with the intent of the royalty reduction statutes, regulations, and to the extent feasible, the Milne Point Unit agreement; (2) it is founded on accepted geologic and engineering principles; (3) it can be applied impartially to all applicants for royalty reduction; and (4) it will generally result in reproducible results when applied by different qualified petroleum geologists.

This definition allows the department to consider all the relevant information with regard to royalty reduction. Commonality of production and transportation facilities and well bores, as well as shared information and economies of scale provided by having multiple stacked reservoirs under a single lease are important factors in the development of an oil field. Not only do multiple stacked reservoirs have lower development costs, but their development also entails lower risk wells. For example, wells can be plugged back and produced from the shallower horizon if the deeper horizon is not produced due to faulting, lack of sufficient net pay, well bore damage, depletion or other factors. The department's definition of "field" is similar to that used by AOGCC in that it considers multiple vertically separated pools or reservoirs underlying the same lease or leases a single "field."

Utilizing a definition that encompasses all reservoirs or pools within the Milne Point Unit also helps minimize the incentive for the operator and lessees to manipulate production and/or costs from individual reservoirs within the Unit for the purposes of affecting royalty reduction applications.

Note that the department's definition does not prohibit the commissioner from granting selective relief to individual pools or reservoirs, or even individual leases. In this case, the ability to do so is clearly stated by the Milne Point Unit Agreement and not prohibited by statute.

IV. Definition of Reasonable Rate of Return

Similarly, regardless of whether one is guided by State law or the Milne Point Unit Agreement, the applicant and the department disagree on what constitutes "a reasonable rate of return" for the purpose of evaluating a royalty reduction request. Without providing objective standards, both AS 38.05.180(j) and the Milne Point Unit Agreement leave it up to the commissioner to define a reasonable rate of return for royalty reduction purposes. Against this backdrop, the department has an obligation to adopt a standard that is objective and which may be applied consistently without regard to the vagaries of the financial planning standards of individual companies. Furthermore, the standard should provide a positive real rate of return (more than inflation), yet not allow for excessive profit at the expense of the state's royalty share.

Oxy has argued in its August 27, 1990 supplemental brief and in testimony at the public hearing, that, at a minimum, a reasonable rate of return, for royalty reduction, should be defined as the cost of capital to the company plus a marginal profit. There are obvious problems with this standard. First of all, such a standard would vary widely from company to company. Based upon information available to the department, Oxy had a cost of capital at a nominal rate of 9.26%. The eight major North Slope producers' cost of capital ranged from a low of 9.26% (Oxy) to a high of 12.75% (Conoco). Additionally, financial data of this sort are generally not directly available to the public, rates are difficult to monitor over time, and many projects are internally financed by the companies.

Thus, defining a reasonable rate of return standard as the individual firm's cost of capital is not acceptable since it treats every firm differently and as such a rate is difficult if not impossible to verify. Such a standard would provide a different level of relief based upon the company, regardless of the field. To protect the state's interest, royalty relief should be based on the economics of the field and not on a company's real or perceived internal financial characteristics. Further, the standard should be impartially applicable to all lessees. A reasonable rate of return that is

independent of the particular company financing involved should be adopted to avoid possible manipulation of in-house economics simply for royalty reduction purposes.

In its August 27, 1990 supplemental brief, Oxy, like Conoco, cites a number of public utilities law cases in support of its proposed definition of rate of return. These cases are intended to demonstrate examples where the most strict standard for a reasonable rate of return is the cost of capital. However, for royalty reduction purposes, these are invalid analogs. A public utility is granted a rather generous (but capped) rate of return since it is regulated and at the same time must compete with unregulated firms in the capital market. Also, a public utility does not have an opportunity to make large profits in other settings, as does a large, privately owned integrated oil company such as Oxy. Neither Oxy's prices nor its costs are regulated by a public agency; therefore, Oxy has no regulated limits on its potential profitability.

It is the potential for large profits that allows Oxy, or any other oil and gas lessee for that matter, to take the risks inherent in wildcat exploration and oil field development. This provides a freedom of operation not granted to a public utility. It is therefore only proper that a more conservative standard for rate of return be applied to Oxy, and other lessees, in determining whether, and to what extent, a reduction in the state's royalty share of production is appropriate. When all the arguments are stripped away, the stated purposes of the royalty reduction statutes are to prolong the economic life of the field and protect the public interest, not to guarantee the state's lessees a minimum rate of return on every field which they choose to develop.

Standards other than those suggested by Oxy are available to define a reasonable rate of return. For example, the economic yardstick used by the United States Geologic Survey and the U.S. Department of Energy in recent studies has been an after-tax rate of return of 8%. Referring to the development of North Slope reserves in *Economics and the National Oil and Gas Assessment, The Case of Onshore Northern Alaska* (In press Attanasi, Bird, and Mast) the authors state "Fields were considered

commercially developable if a discounted cash flow analysis showed that an after-tax return of 8 percent could be achieved. At the time of the assessment, the 8 percent hurdle rate was being used by the U.S. Department of Energy's Energy Information Administration in the national energy base case forecasts (Jon Rasmussen, Energy Information Administration, oral communication)."

Another potential yardstick for defining a reasonable rate of return is the standard used by the State of Alaska Department of Revenue (DOR) in determining reasonable shipping rates for North Slope crude for the purpose of calculating severance tax obligations. Shippers are allowed the Gross National Product deflator (GNPd) plus two percentage points return to capital as allowable expenses (profits). For the 1980-1989 period, the GNPd fell short of the 90 day Treasury bill rate by 4.4 percentage points. Otherwise stated, DOR has allowed, as a reasonable rate of return, a rate which is, on average, 2.4 percentage points less than the 90 day Treasury bill rate.

The standard which I recommend the department choose to define a "reasonable rate of return" for the purposes of this application is the rate of return for a 90 day Treasury Bill. For the period of 1980-1989 the real rate of return for the 90 day bill was approximately six percent. This standard compares favorably with other potential standards examined by the department.

V. Discretionary Nature of Royalty Reduction

A well established rule of interpretation specifies that "may" refers to discretionary action, while "shall" dictates mandatory action. Similarly, "may not" constitutes a mandatory prohibition.

AS 38.05.180(p) states the commissioner "may ... change ... royalty requirements" Paragraph 18(h)(8) of the Milne Point Unit Agreement provides that the State "may reduce Lessee's obligation to pay royalty" Thus, both AS 38.05.180(p) and paragraph 18(h)(8) of the Milne Point Unit Agreement permit royalty reductions, but they do not mandate royalty reductions, except where a denial of a royalty reduction would be arbitrary or unreasonable.

AS 38.05.180(j), both before and after amendment by HB 128, mandates promulgation of regulations governing applications for royalty reduction: "the commissioner shall adopt regulations" However, the regulations are "to allow reduction of royalty" The word "allow," like "may," is permissive, not mandatory. AS 38.05.180(j), both before and after amendment by HB 128, then uses mandatory language to specify one instance in which royalty reduction is not allowed: "The commissioner may not grant a reduction of royalty" unless the applicant has made a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field. In short, while AS 38.05.180(j) contains some compulsory directives, it also permits denial of an application where not unreasonable or arbitrary to do so.

VI. Evaluation of Application Under AS 38.05.180(p)

AS 38.05.180(p) states:

To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest.

(Emphasis added).

Oxy's application, as initially submitted, represented that the Milne Point Unit Kuparuk Formation had an expected field life of twenty-five years, three years of which have now elapsed. Oxy's application states that if the State reduced its royalty to 5%, the Kuparuk formation would produce 1.8 million barrels more

than it would otherwise produce in the three years following the first twenty-five years of production. Given a working interest of 10.477%, Oxy's gross share of this additional production equals approximately 194,000 barrels.

In evaluating Oxy's application, the department must determine whether the public interest would best be served by the State's receipt of a 20% royalty over a remaining field life of twenty-two years, or by the State's receipt of a 5% royalty over a remaining field life of twenty-five years and the production of an additional 194,000 barrels of oil twenty-two to twenty-five years from now. This determination cannot be made without reference to the wellhead value of Milne Point oil.

It is impossible to accurately calculate the wellhead value of production occurring over the next twenty-two to twenty-five years.. The impossibility of the task is exemplified by the wide range of values for oil produced from the Kuparuk Formation in the Milne Point Unit in 1990 alone, when the reported wellhead value over doubled between June and September. However, the department is able to model the effects in a gross sense by selecting a low estimated average value and a high estimated average value, then calculating the costs and benefits of granting the requested royalty reduction should values approaching either of these extremes prove accurate.

In this analysis, the department selected a low average Milne Point wellhead value of \$12 per barrel and a high average Milne Point wellhead value of \$22. These wellhead values were chosen to represent possible average wellhead values for the entire life of the field. These wellhead values roughly correspond with United States West Coast average prices of \$20 and \$30 per barrel, respectively.

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is \$12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose approximately \$10,000,000 in royalties on oil produced during the next twenty-two years, and gain approximately \$116,000 in royalties on oil produced twenty-two to twenty-five years from now. Total direct benefit from Oxy's additional production under a reduced royalty rate is estimated to be 194,000 barrels of oil valued at \$2,328,000.

Assuming that the average wellhead value is \$22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose approximately \$17,000,000 in royalties on oil produced during the next twenty-two years, and gain approximately \$213,000 in royalties on oil produced twenty-two to twenty-five years from now. The incremental volume of oil that would be produced due to a royalty reduction in this case would be valued at approximately \$4,268,000.

Under both scenarios the cost of the royalty reduction to the State is roughly four times the combined value of the direct benefits to the state and public. These analyses were conducted in constant 1989 dollars. Obviously, had they been done in present value terms, the disparity between costs and benefits would have been even greater.

But there are other benefits which may be obtained by reducing the royalty rate to 5%. By letters dated May 16 and October 9, 1990, the field operator, Conoco, committed to expand its 3-D seismic program, and, dependent on the outcome of the seismic program, possibly drill two additional wells to evaluate three regions of the Kuparuk Formation within the Milne Point Field. These wells would be targeted to delineate the resource potential of several small fault blocks and/or the down-dip limit of the field. Conoco first termed the magnitude of reserve additions attributable to these operations as "totally speculative." Subsequently, Conoco provided reserve estimates for one of the three regions and risk factors for all three regions. Based on the relatively low reserve estimate, coupled with the risk factor, the conditional nature of the commitment to drill, and ownership interests of other parties in the reserves, the department concludes that the potential incremental benefits of royalty reduction are insufficient to tip the scales in favor of granting the reduction requested.

If future seismic acquisition and interpretation supports Conoco's current geologic mapping, and the State reduces its royalty to five percent, Conoco will drill two additional production wells which, based on Conoco's expectations, could produce approximately an additional 3 million barrels of oil. Assuming all this additional production underlines leases in which Oxy has a working interest, its share of this additional production would be 314,310 barrels of oil. The state's royalty share of this production at the five percent royalty would be 15,715 barrels. Other benefits from this additional drilling would include the

short term employment of a rig crew and support personnel (approximately two weeks to drill and complete each well). Unequivocally, the value of speculative additional production that may be derived from this additional drilling is inadequate to offset the forgone royalty.

Based on the extraordinary value of lost royalties, the modest benefit of a potential 194,000 barrel increase in production, and the highly speculative, conditional, and relatively minor benefits of Conoco's and Oxy's commitment to additional exploration and development activities, it is extremely difficult to make a finding that granting the royalty reduction which Oxy requests is either necessary or proper to secure the proper protection of the public interest.

VII. Evaluation of Application Under AS 38.05.180(j), Prior to Amendment By HB 128 in 1990

AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Oxy's application was submitted, stated:

AS 38.05.180(j) "To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field."

(Emphasis added).

As with AS 38.05.180(p), relief under AS 38.05.180(j) is discretionary. However, the department should not exercise its discretion in favor of royalty reduction unless the reduction is in the public interest. For the reasons discussed in Part VI, above, granting the royalty reduction as requested by Oxy is not in the public interest.

To qualify for relief under AS 38.05.180(j), an applicant must establish that the relief requested: (1) follows two years initial production from the field; (2) will prolong the economic life of the field; (3) will compensate for increasing costs in the later stages of production decline; **and** (4) is necessary to produce a reasonable rate of return on the applicant's total investment in the field.

Oxy submitted its application for royalty reduction immediately following two years of cumulative production from the Kuparuk Formation of the Milne Point field; therefore, the requirement of two years initial production from the field has been met. However, Oxy has not established that the requested royalty reduction will significantly prolong the economic life of the field. While the field life **might** be extended by three years, more than twenty years in the future, the number of years added or not added is not relevant--the number of additional barrels recovered is the primary factor to consider. Oxy's unconditional commitment to increased production is limited to 194,000 barrels. This volume represents only a tiny portion of the estimated production for the Kuparuk Formation, and an even lesser percentage of estimated production for the Milne Point field. Given the cost to the State of the royalty reduction requested, the amount of potential new production 20+ years hence is almost inconsequential in both absolute and relative terms.

Having failed the second part of a four part test for royalty reduction under AS 38.05.180(j), it is unnecessary to examine elements three and four. However, brief mention of the two remaining elements is appropriate. AS 38.05.180(j) restricts royalty reduction to instances in which it will compensate for increasing costs in the later stages of production decline. First, the department has received no information that would indicate the Milne Point field is in the later stages of production decline. To the contrary, Conoco, the field operator, has announced plans to develop the Schrader Bluff Formation within the Milne Point field with the ultimate goal of at least doubling overall production from the field. Oxy has the option to participate in this field development project. Second, the department interprets this requirement as limiting the amount of relief which may be granted to that amount necessary to offset the increase in costs. It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the

later stages of production decline. Given the volatility of future oil prices and the remoteness of late-stage costs, the department should not conclude that this standard would be met by granting the requested royalty reduction at this time.

Finally, AS 38.05.180(j) requires the applicant to make a clear showing that the revenue generated by the field is insufficient to produce a reasonable rate of return on the total investment in the field. A clear showing requires evidence which is precise, explicit, and which directly establishes the point. It is very difficult, if not impossible, to provide such evidence here, since the Milne Point field is in the very early stages of production. Use of estimated value, production, and cost data for the remaining twenty-two to twenty-five year life of the field adds a high level of uncertainty to determining the long-term validity of any purported "need" for Oxy's royalty reduction. Particularly disturbing is the unreliability inherent in estimating the value of oil to be produced over the next twenty-two to twenty-five years. As mentioned earlier, this unreliability is dramatically underscored by the over doubling of reported wellhead values from the Milne Point Unit between June and September 1990.

Estimating revenue from future production is further complicated by a lack of knowledge regarding the potential volume and value of future production from other pools in the Milne Point field, such as the Schrader Bluff Formation, as well as by price and technology sensitive enhanced oil recovery techniques which may significantly increase total production from all reservoirs or pools within the Milne Point field.

On the other hand, since much of the major field facility development has already occurred, the cost estimates for the remaining field life are easier to approximate. According to the data submitted by Conoco on June 13, 1990, about 87% of the capital investment in field facilities has been completed, leaving only relatively minor capital investment expenses to be estimated. This, however, does not include the costs associated with Schrader Bluff development and production.

In short, the department may reasonably conclude it impossible to make a clear showing that the revenue generated by the Milne Point field over its entire life will be insufficient to produce a reasonable rate of return on the total investment

in the field when but a small fraction of the minimum estimated field life has transpired.

In conclusion, Oxy's application should not be granted as requested under AS 38.05.180(j) (as it existed before it was amended by HB 128). Oxy has not established that reducing the royalty rate on the Kuparuk Formation from 20% to 5% would significantly prolong the life of the Milne Point field. A minimal extension of the field at a very high cost to the State is not in the public interest. Furthermore, the uncertainties inherent in estimating revenue and costs for the next twenty-two to twenty-five years allow the commissioner to conclude that Oxy cannot adequately show either the magnitude of increasing costs in the later stages of production decline or total field life rate of return.

**VIII. Evaluation of Application Under AS 38.05.180(j). As Amended
By HB 128 in 1990.**

AS 38.05.180(j) was amended by HB 128, effective September 12, 1990. It now reads:

To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible, the commissioner shall adopt regulations to allow reduction of royalty on leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way to protect the state's interest, including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that the state has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee, and send copies of the finding to all members of the legislature.

(Emphasis added).

As with AS 38.05.180(p), and AS 38.05.180(j) prior to its amendment by HB 128, relief under the amended standard is discretionary. The department, however, should not exercise its discretion in favor of royalty reduction unless the reduction is demonstrated to be in the public interest. For the reasons discussed in Part VI, above, granting royalty reduction as requested by Oxy, is not in the public interest.

Under AS 38.05.180(j) as amended by HB 128, royalty relief cannot be granted unless it will either prolong the economic life of an oil and gas field or reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible. The royalty reduction requested by Oxy will not substantially prolong the economic life of the Kuparuk Formation or Milne Point field for the reasons discussed in Part VII, above. Nor is the Kuparuk Formation shut-in, as it was previously. Therefore, Oxy's application fails these alternative requirements of AS 38.05.180(j), as amended by HB 128.

As 38.05.180(j), as amended, also retains the requirement of a clear showing that revenue from the field is insufficient to produce a reasonable rate of return on total field investment. The department's analysis of this requirement is the same under both the former AS 38.05.180(j) and its current amended version. (See Part VII, above).

The 1990 amendment to AS 38.05.180(j) specifies that an application for royalty reduction cannot be approved unless the commissioner makes a written finding that the State has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the applicant. Due to volatile oil prices, risks inherent in oil and gas production, and uncertain future costs, the department cannot find that the State will obtain its maximum possible economic return without providing for the recapture of foregone royalties in the event a lessee ultimately achieves more than a predetermined reasonable rate of return. However, in this instance the department need not craft a limited or conditional royalty relief, since the royalty relief requested is inappropriate for other reasons, as discussed above.

IX. Milne Point Unit Agreement. Paragraph 18(h)(8)

Oxy argues in its August 27, 1990 supplemental brief that paragraph 18(h)(8) of the Milne Point Unit Agreement governs its application for royalty reduction; and that AS 38.05.180 (p) and (j) apply only to the extent that they are not inconsistent with the unit agreement. Paragraph 18(h)(8) states:

Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

Oxy's argument that paragraph 18(h)(8) prevails where inconsistent with AS 38.05.180(p) or (j) appears to be based on an incomplete reading of paragraph 1 of the Unit Agreement, which states:

The Alaska Land Act ... and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska are hereby accepted and made a part of this agreement.

(Emphasis added). Oxy chooses to ignore that all statutes not inconsistent with the laws of the State of Alaska are incorporated by reference in the Unit Agreement. Since the statutes are the laws of the State of Alaska, they cannot be inconsistent with the laws of the State of Alaska (except to the extent that one or more statutes are contrary to the United States or Alaska constitutions). Therefore, AS 38.05180(j) and (p) are incorporated by reference in the Unit Agreement, and are thus every bit as much a part of the Unit Agreement as is paragraph 18(h)(8).

In any case, a state agency is without authority to enter into an agreement in conflict with applicable statutes. Thus, even without an explicit incorporation of

Alaska's statutes by reference in Paragraph 1 of the Milne Point Unit Agreement, the statutes control when in conflict with the Unit Agreement.

X. Summary

In this instance, I have recommended that the requested royalty reduction should be denied under AS 38.05.180(p), (j), and (j), as amended by H.B. 128 since the department concludes that Oxy has failed to demonstrate:

- (1) that granting the requested royalty relief will be in the public interest;
- (2) that reducing the royalty from 20% to 5% will significantly prolong the economic life of the field; and
- (3) a clear showing that its revenue from oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Oxy's total investment in the field.

The statutes and regulations do not discuss the quantity or quality of data needed to demonstrate a clear showing (though, obviously, "clear showing" is a high standard) that Oxy's revenue from the field is insufficient to produce a reasonable rate of return with respect to its total investment in the field. Similarly, the statutes and regulations do not list precisely the quantity or quality of data needed to demonstrate that the economic life of the field will be significantly prolonged by a royalty reduction. These determinations must be made by the commissioner based on the discretionary power granted by the statutes, department regulations, and the Milne Point Unit Agreement. However, it becomes apparent that, especially in the case of a field such as Milne Point, with only a few years of production history, determining the long term profitability of the field with any certainty is virtually impossible, especially when the lessees

continue to produce oil and develop new reserves under the existing 20% royalty rate.

Even though it is recommended that Oxy's application for a royalty reduction to 5% be denied, the division felt obligated to carefully analyze the data submitted to determine if an alternative approach for royalty reduction could be developed which would meet the statutory requirements. Among the possibilities examined were a sliding scale royalty based on wellhead value, short term relief, relief down to a floor of 12.5%, and combinations of these three methodologies. These limited and/or conditional alternatives to a complete denial were determined to be unacceptable since in all cases examined, even ignoring Oxy's failure to make a clear showing, the estimated benefit to the state and public was substantially less than the estimated revenue lost by the state in forgone royalty. Therefore, even a limited or conditional royalty does not appear to be in the public interest at this time.

ENCLOSURE 5

Mark Myers

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
FIRST JUDICIAL DISTRICT AT JUNEAU

CONOCO, INC., a Delaware
Corporation, and OXY USA, INC.,

Plaintiffs,

STATE OF ALASKA, DEPARTMENT OF
NATURAL RESOURCES,

Defendant.

No. 1JU-91-796 CI

ORDER

On August 28, 1991, oral argument was held on the state's motion to dismiss. After hearing the arguments, the court granted the state's motion but delayed a final ruling pending review of the proprietary/governmental distinction argued by Conoco. The court has reviewed this issue and holds that although some jurisdictions would apply this distinction, the direction of the Supreme Court to date appears to require dismissal of this action.

In University of Alaska v National Aircraft Leasing, Ltd., 536 P.2d 121, 128 (Alaska 1975), the Alaska Supreme Court noted that it had previously abandoned the proprietary/governmental distinction with respect to municipal tort liability analysis in City of Fairbanks v Schaible, 375 P.2d 201, 208 (Alaska 1962). The Court then extended the Schaible

1 ruling to suits involving the state or its agencies in tort
2 liability cases. University of Alaska, 536 P.2d at 128. The
3 Court noted that other jurisdictions still acknowledged the
4 proprietary/governmental distinction, but refused to follow those
5 jurisdictions. Id.

6 More recently, the Court refused to apply the distinction
7 to a dispute involving real property. Mount v Curran, 657 P.2d
8 392; 395 (Alaska 1982). The Court recognized that other
9 jurisdictions allow land to be adversely possessed against
10 municipalities if the municipal land is not being held for public
11 purposes. Id. The Court pointed out that this exception to the
12 general rule prohibiting adverse possession against the
13 government is a reflection of the proprietary/governmental
14 distinction. Id. Again, as in the previous cases, the Alaska
15 Supreme Court refused to follow the jurisdictions recognizing the
16 distinction.

17 In a 1986 case, the Supreme Court made reference to the
18 distinction in the context of a local hire issue. Robinson v
19 Francis, 713 P.2d 259, 264 (Alaska 1986). The Court discussed
20 the distinction and its impact on the analysis employed under the
21 privileges and immunities clause, but did not hold that Alaska
22 had or would adopt the use of the distinctions in this or other
23 areas of legal analysis. Id.

24 Conoco has called the court's attention to several out-
25

1 of-state cases that specifically apply the distinction in
2 situations similar to the situation occurring here. Again,
3 however, the Alaska Supreme Court has recognized that other
4 jurisdictions have relied on the distinction in various
5 situations. Nonetheless, in two situations, tort liability and
6 municipal real estate problems, the Court held that the
7 distinction would not be applied. This court believes that the
8 Alaska Supreme Court will not follow the out-of-state precedent
9 in this instance.

10 Furthermore, in at least two of the cases relied on by
11 Conoco, distinct statutory differences exist.

12 In, General Land Office of State of Texas v Rutherford
13 Oil Corporation, 802 S.W.2d 65, 69 (Texas App. 1990), the Texas
14 court held that the GLO only had the statutory authority to audit
15 the books, but it did not have the authority to require payment
16 of the royalties. Likewise, in Anson Company v Commissioner of
17 the Land Office of the State of Oklahoma, Order 74766 Oklahoma
18 Supreme Court (March 26, 1988), that court held that the oil and
19 gas lease did not give the commissioners adjudicative authority
20 over the rights of the parties. Here, paragraph 18(h)(8) and
21 A.S. 38.05.180(j) and (p) give the Department of Natural
22 Resources Commissioner the authority to determine royalty
23 reduction.

24 Conoco also questioned why the state was able to seek
25

1 original jurisdiction in the Amerada Hess litigation (now called
2 the North Slope Royalty Litigation) and yet in this case, the
3 same option is being denied. In Amerada Hess, the parties
4 contractually agreed to litigation if they could not resolve the
5 issues themselves. See, ANR Royalty Litigation, LJU-77-047 CX,
6 Plaintiff's Complaint for Declaratory Judgment, Para. 31. Here,
7 Conoco contracted to have the determination of royalty reduction
8 decided by DNR.

9 Finally, Conoco argues that there was an inadequate
10 administrative process provided in this matter. However, even if
11 this is true, Conoco has a remedy through the appellate process.
12 The matter may be remanded back to the administrative agency for
13 appropriate proceedings.

14 For the above reasons, the state's Motion to Dismiss is
15 granted.

16 DATED at Sitka, Alaska, this 10th day of September, 1991.

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Larry V. Gervus
Superior Court Judge

Alaska Court System

TOTAL P.03

TOTAL P.04

TOTAL P.05

ENCLOSURE 6

Jim K BTEE KSTO

RECEIVED
Department of Law

THE SUPREME COURT OF THE STATE OF ALASKA JUN 09 1993

CONOCO, INC., a Delaware
corporation, and OXY USA,
INC., a Delaware corporation,
Appellants,
v.
STATE OF ALASKA, DEPARTMENT
OF NATURAL RESOURCES,
Appellee.

Office of the Attorney General
Anchorage Branch
Supreme Court File No. *8-1803*
Superior Court File No.
1JU-91-796 Civil

MEMORANDUM OPINION
AND JUDGMENT

[No. 0668 - June 9, 1993]

Corono Melne Pt
Royalty Reduction
file

Appeal from the Superior Court of the State of
Alaska, First Judicial District, Juneau, Larry
C. Zervos, Judge.

Appearances: Jeffrey W. Bush and Jonathan K.
Tillinghast, Birch, Horton, Bittner & Chert
Juneau, for Appellants. ~~Barbara J. Broughton~~
Assistant Attorney General, Anchorage, and
Charles E. Cole, Attorney General, Juneau, for
Appellee.

Before: Moore, Chief Justice, Rabinowitz,
Burke, Matthews, and Compton, Justices.

I. INTRODUCTION

This case arises from a dispute between the Department
of Natural Resources (DNR) and two oil companies--Conoco, Inc.
(Conoco) and OXY USA, Inc. (OXY)--over the interpretation of a
royalty reduction clause in an oil and gas lease unit agreement.
After DNR denied them a royalty reduction, Conoco and OXY filed
two suits: an administrative appeal challenging DNR's decision,
and an original action raising several claims in contract. On the
state's motion, the superior court dismissed the original action,
concluding that Conoco and OXY must pursue all their claims in the

* Entered pursuant to Alaska Appellate Rule 214.

administrative appeal. The court also awarded attorney's fees to the state. We affirm.

II. FACTS AND PROCEEDINGS

This case involves four oil and gas leases on the North Slope. The predecessor in interest to Conoco and OXY obtained these leases in 1969, and paid a 12.5 percent royalty to the state. In 1979, Conoco and OXY's predecessor in interest proposed to consolidate the leases, which were about to expire, and form a unit agreement. DNR, however, refused to approve the unit agreement without an increase in the royalty rate to 20 percent. The parties agreed to the rate increase. A provision of the unit agreement permits the state to grant a royalty reduction if production from the oil field is low. The state and the two companies dispute whether this clause requires DNR to grant Conoco and OXY a royalty reduction.

In 1990, Conoco and OXY applied for a reduction in the royalty rate to five percent. The process by which DNR reviewed the application involved public but nonadversarial hearings, which were not adjudicatory in nature. Conoco and OXY allege numerous flaws in the review process, including the absence of any adjudicatory hearing, the lack of an opportunity to cross-examine DNR staff, and the existence of ex parte communications between DNR staff and the officer presiding over the hearings. The hearing officer recommended that the Commissioner of Natural Resources deny

the applications for royalty reduction. The Commissioner substantially adopted this recommendation, and denied the applications.

In response, Conoco and OXY filed two actions in the lower courts. One was an administrative appeal to the Superior Court, brought under Part Six of the Appellate Rules,¹ and challenging the Commissioner's decision. Conoco, Inc. v. State, Dep't of Natural Resources, No. 1JU-91-797, 798 CI (Consolidated) (Alaska Super., Mar. 17, 1992). The other was an original, independent action before the superior court, raising claims in contract, and demanding a jury trial. The companies sought judgment in their favor for, among other things, specific performance, a reduction in the royalty rate, reformation of the unit agreement, and damages.

In the original action, the state brought a motion to dismiss under Alaska Civil Rule 12(b)(1) for lack of subject matter jurisdiction.² Judge Larry Zervos granted the state's motion and

1 Where the law allows for appeals of an administrative agency's actions, the superior court exercises jurisdiction over such appeals. AS 22.10.020(d). Part Six of the Appellate Rules (Rules 601-612) governs administrative appeals to the superior court. Alaska R. App. P. 601(a).

2 Civil Rule 12(b) states in part:

Every defense, in law or fact, to a claim for relief in any pleading . . . shall be asserted in the responsive pleading thereto if one is required, except that the following defenses may at the option of the pleader be made by motion: (1) lack of jurisdiction over the subject matter

dismissed Conoco's and OXY's contract claims, holding that the companies must raise them in the administrative appeal. Judge Zervos subsequently awarded attorney's fees to the state. Conoco and OXY appeal Judge Zervos's decision.³

III. DISCUSSION

No matter how it is denominated, a claim is functionally an administrative appeal, and a party must raise it as such, if it requires the court to determine the propriety of an agency determination. E.g., Fairbanks N. Star Borough v. State, 826 P.2d 760, 762 (Alaska 1992); see also Fedpac Int'l. Inc. v. State, Dep't of Revenue, 646 P.2d 240, 241 (Alaska 1982); Alaska R. App. P. 602. If a plaintiff tries to style a suit as an independent action by raising issues different from those that the agency considered, but the relief sought is basically identical to that sought from the agency, then the suit must be dismissed. Fairbanks N. Star Borough, 826 P.2d at 763; Fedpac Int'l. Inc., 646 P.2d at 240-41.

Even when a dispute involves contractual issues, plaintiffs must nonetheless pursue their claims by an administrative appeal, rather than an original action. See, e.g., Fairbanks N. Star Borough, 826 P.2d at 761, 764-65 (questions of rescission and mutual mistake regarding easement agreement);

³ Conoco and OXY also discuss the outcome of the administrative appeal before Judge Weeks. Because this appeal challenges Judge Zervos's action, we will not discuss the propriety of Judge Weeks's decision. If Conoco and OXY disagree with Judge Weeks's decision, they may appeal it separately.

Diedrich v. City of Ketchikan, 805 P.2d 362, 365-66 (Alaska 1991) (alleged breach of an employment contract); State v. Lundgren Pac. Constr. Co., 603 P.2d 889, 890, 892-93 (Alaska 1979) (dispute over contract to build ferry terminals). To do otherwise would let almost any litigant avoid the administrative appeal rules, just by alleging contract or other common law claims in his or her complaint. See Fedpac Int'l. Inc., 646 P.2d at 242.

Conoco and OXY's contract claims do not entitle the two companies to an original, independent action. The companies argue that their claims are not in fact related to DNR's decision, because they seek a reformation of the unit agreement to delete the 1979 royalty increase altogether, not simply a reversal of DNR's decision. The claim for reformation, the companies argue, could have been brought at any time, and is raised along with the appeal only because until now they were not aware of how DNR would read the disputed provisions. Nevertheless, the objective of Conoco and OXY clearly is to escape the unit agreement's current royalty rates, through either a reversal of DNR's decision or a reformation of the agreement to eliminate the increase in rates from the start. Therefore, no matter how they characterize their claims, Conoco and OXY in effect have challenged DNR's denial of a rate reduction, and must pursue their remedies through an administrative appeal.⁴

⁴ Conoco and OXY also argue that under this court's holding in Owsichuk v. State, Guide Licensing & Control Bd., 627 P.2d 616 (Alaska 1981), they are entitled to file an original action because their suit includes claims for declaratory judgment. If a request (continued...)

Conoco and OXY argue that because DNR's leasing arrangements put the agency in the position of a private market participant, the companies may sue the agency in an original action, just as they could with any other private party. However, we have not recognized a distinction between an agency's proprietary and governmental activities. E.g., Mount v. Curran, 657 P.2d 392, 395 (Alaska 1982) (disallowing adverse possession of public property, even if state acquired property for nonpublic purpose); University of Alaska v. National Aircraft Leasing, Ltd., 536 P.2d 121, 128-29 (Alaska 1975) (refusing to apply distinction to university activities). In particular, we have rejected the argument that DNR's involvement in oil and gas leasing was a proprietary function. State, Dep't of Natural Resources v. Arctic Slope Regional Corp., 834 P.2d 134, 143 (Alaska 1991) ("We find the line the companies draw between 'regulatory' and 'proprietary' functions more clear in theory than in practice."). Holding that the mandatory disclosure to DNR of data on exploratory wells is not a taking of property, we found that DNR's activities promoted the general welfare of the citizenry and were thus a valid exercise of

4 (...continued)
for a declaratory judgment requires review of only a statute or a regulation, and not an agency decision, then the provisions for administrative appeals do not apply, and a plaintiff may pursue an original action. Owsichuk, 627 P.2d at 619 (interpreting predecessor to Appellate Rule 602). Here, the companies' declaratory judgment claims ask the court to interpret the provisions of the unit agreement, not a statute or regulation. Therefore, Conoco and OXY seek a direct review of DNR's decision, and Owsichuk's rule on declaratory judgments is inapplicable.

the police power.⁵ See id. at 143-44, 145.

Assuming that Conoco and OXY's complaints about DNR's review process are valid,⁶ they nonetheless do not require an original action. If the court on appeal finds that agency procedures did not conform with due process requirements, then the remedy is not an original action, but rather a trial de novo on appeal. Lundgren Pac. Constr. Co., 603 P.2d at 896. If agency procedures themselves are proper, but they were not followed in a particular case, then the remedy is a remand to the agency. Id. If less formal agency hearing procedures lead to defects in the record, such flaws may be corrected in the administrative appeal. Fedpac Int'l. Inc., 646 P.2d at 243. Thus the proper vehicle for challenging DNR's review process remains an administrative appeal. We need not examine the process to conclude that an original action would be inappropriate.

Because an administrative appeal is the proper vehicle for the claims of Conoco and OXY, the parties have no right to a jury trial. In civil cases, the right to a jury trial "is preserved to the same extent as it existed at common law." Alaska

5 To reach our conclusion, we looked to the legislative intent behind Alaska's statutes on oil and gas leases. See AS 38.05.180(a), quoted in part in Arctic Slope Regional Corp., 834 P.2d at 143.

6 In reviewing a motion to dismiss under Civil Rule 12(b), a court must presume all the factual allegations in the complaint to be true, and must view the evidence in the light most favorable to the nonmoving party. Kollodge v. State, 757 P.2d 1024, 1026 (Alaska 1988).

Const. art. I, § 16. On the other hand, in cases where questions of fact arise under statutory actions rather than common law, a court may decide such issues without a jury. Diedrich v. City of Ketchikan, 805 P.2d 362, 366-67 (Alaska 1991) (deeming an administrative appeal the proper vehicle for employee's wrongful discharge suit); see also Benson v. City of Nenana, 725 P.2d 490, 491 (Alaska 1986) (in case under Workers' Compensation Act, allowing bench trial without jury where exclusive remedy defense raised). DNR has the power to administer oil and gas leases and determine royalty reductions in the interest of the general welfare. See AS 38.05.180(a), (f), (j). The legislature also provided for administrative appeals of agency determinations. AS 22.10.020(d); see Alaska R. App. P. 601-612. Therefore, no jury trial is required, because no action at common law exists here.⁷

Additionally, Conoco and OXY contend that Judge Zervos should not have awarded attorney's fees under Alaska Civil Rule 82, because this case had no prevailing party. We will overturn the trial court's determination of a prevailing party only for an abuse of discretion. Howard S. Lease Constr. Co. v. Holly, 725

⁷ Conoco and OXY extensively analyze the jurisprudence of the U.S. Supreme Court, arguing that this body of law supports their arguments for a jury trial. However, the Seventh Amendment of the U.S. Constitution does not apply to state court proceedings. E.g., Minneapolis & St. Louis R.R. v. Bombolis, 241 U.S. 211, 217 (1916). The U.S. Supreme Court case on which Conoco and OXY rely most heavily finds a right to a civil jury trial when the government acts in a private proprietary capacity. Granfinanciera, S.A. v. Nordberg, 492 U.S. 33, 51-52 (1989). In Alaska, no distinction between proprietary and governmental capacities as yet exists.

P.2d 712, 720 (Alaska 1986). A prevailing party is one who wins on the main issue in dispute, provided that the issue has been joined. Foss Alaska Line, Inc. v. Northland Servs., Inc., 724 P.2d 523, 526 (Alaska 1986).

A dismissal for lack of subject matter jurisdiction is without prejudice, so in a technical sense no issues have been joined and no prevailing party yet exists. On the other hand, we do not approach the definition of a prevailing party in such a rigid fashion. See Miller v. Wilkes, 496 P.2d 176, 178 (Alaska 1972) (upholding award of attorney's fees to defendant, even though plaintiff had voluntarily dismissed case without prejudice under Alaska Civil Rule 41, where issue practically had been joined because defendant filed documents resembling an answer); Hart v. Wolff, 489 P.2d 114, 119 (Alaska 1971) (upholding award of attorney's fees to defendant after dismissing plaintiff's complaint without prejudice for failure to comply with a discovery order). Conoco and OXY's independent action required the state to expend time and money on considerable motion-related paperwork and oral arguments, even if the state simply challenged the trial court's jurisdiction. Therefore, the issues here were joined in a practical sense, and Judge Zervos did not abuse his discretion by awarding the state attorney's fees.

AFFIRMED.

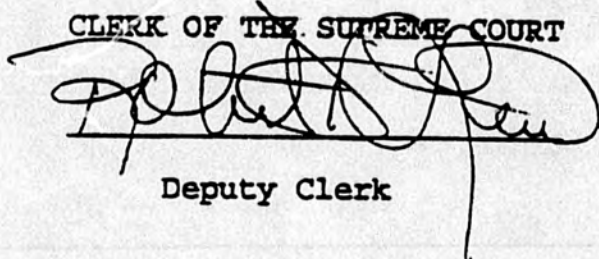
ORDER AWARDING FEES AND COSTS

File No. S-4803

Under Appellate Rules 508(e) and (f) (1), attorney's fees of \$1000 are awarded to appellee, and appellee shall serve and file with this court by June 21, 1993 an itemized and verified bill of costs in compliance with Appellate Rule 508(d).

Entered at the direction of on June 9, 1993.

CLERK OF THE SUPREME COURT

A handwritten signature in black ink, appearing to be "D. A. [unclear]", is written over a horizontal line. The signature is stylized and cursive.

Deputy Clerk

ENCLOSURE 7

Conoco - OXY Settlement

SETTLEMENT AGREEMENT AND MUTUAL RELEASE

This SETTLEMENT AGREEMENT and MUTUAL RELEASE (collectively "Agreement") is effective as of December 30, 1993, by and among Conoco, Inc., ("Conoco"), OXY USA Inc. ("OXY"), and the State of Alaska ("State").

RECITALS

This Agreement is made with reference to the following facts:

Royalty Reduction Facts

1. On February 28, 1990 and June 11, 1990, Conoco and OXY, respectively, applied to the State to reduce the royalty rate on certain State leases within the Milne Point Unit ("MPU"). The Commissioner ("Commissioner") of the Department of Natural Resources ("DNR") denied those royalty reduction applications on April 17, 1991.

2. On May 22, 1991, Conoco and OXY appealed the Commissioner's denial of the royalty reduction applications to the superior court in Conoco Inc. v. State of Alaska, 1-JU-797 Civ., and OXY USA Inc. v. State of Alaska, 1-JU-798 Civ. (collectively "Royalty Reduction Administrative Appeal"). Conoco and OXY claim in the Royalty Reduction Administrative Appeal that they are contractually entitled to pay a five percent royalty on all Kuparuk River formation oil production from certain MPU leases. The State claims that Conoco and OXY are contractually required to pay a twenty percent royalty on Kuparuk River formation production from the MPU leases bearing a twenty percent royalty rate and twelve and one-half percent royalty on production from the remaining leases within the MPU, and that Conoco and OXY are not entitled to a royalty reduction either under applicable statutes and regulations, or the MPU Agreement. The Royalty Reduction Administrative Appeal remains pending before the superior court.

3. On May 22, 1991, Conoco and OXY sued the State in Conoco Inc. and OXY USA, Inc. v. State of Alaska, 1-JU-796 Civ. ("the Contract Action"). In the Contract Action, Conoco and OXY claim damages of not less than \$16 million for alleged breach of the royalty reduction terms of the MPU

1 Agreement, seek a prospective reduction of royalties, and seek to reform the MPU Agreement to remove
2 the contract provision requiring that they pay a twenty percent royalty, rather than a twelve and one-half
3 percent royalty, on certain leases. The State denies any breach of contract or basis for reformation, and
4 asserts that Conoco and OXY may not pursue their royalty reduction dispute with the State through a
5 common law action independent of the Royalty Reduction Administrative Appeal. The superior court
6 dismissed the Contract Action and awarded attorneys' fees and costs of \$2,250 and \$1,087.27, respectively,
7 to the State. Conoco and OXY appealed the dismissal to the Alaska Supreme Court in Conoco Inc. and
8 OXY USA Inc. v. State of Alaska, No. S-4083 (the "Supreme Court Appeal"). On June 9, 1993, the
9 supreme court affirmed the superior court's dismissal of the Contract Action in Conoco, Inc. v. State, Op.
10 No. 0668 (Alaska, June 9, 1993), affirmed the superior court's award of fees and costs, and awarded
11 attorney's fees of \$1,000 to the State for the appeal.

12 Discovery Royalty Facts

13 4. On September 7, 1989, Conoco applied to the State for certification of its Milne Point G-1 well
14 as the first well to discover oil in commercial quantities in the Schrader Bluff formation, and requested an
15 award of a five percent discovery royalty for that well. On January 16, 1992, the Commissioner denied the
16 discovery royalty application.

17 5. On February 14, 1992, Conoco appealed the Commissioner's denial of the discovery royalty
18 application to the superior court in Conoco Inc. v. State of Alaska, 1-IU-92-469 Civ. (the "Discovery
19 Royalty Appeal"). Conoco claims in the Discovery Royalty Appeal that it is entitled to a five percent
20 royalty on Schrader Bluff production from ADL 25906 located in the MPU for a period of 10 years by
21 virtue of the discovery. The State claims that the G-1 well did not first discover oil in commercial quantities
22 in the Schrader Bluff formation, and therefore Conoco is not entitled to a discovery royalty. The Discovery
23 Royalty Appeal remains pending before the superior court.

24 6. On January 14, 1994, OXY requested DNR to partially substitute OXY as the real party in
25 interest for an 8.81% working interest in ADL 25906 as Conoco's successor in interest. OXY represented

1 that it intended to file a motion to substitute or intervene in the Discovery Royalty Appeal. OXY's request
2 remains pending before DNR.

3 Royalty Valuation Facts

4 7. On July 26, 1991, the State informed Conoco and OXY that it believed that they had been and
5 were continuing to improperly value their production from the MPU for royalty purposes. The State
6 asserted that Conoco and OXY had been and were continuing to pay royalties on the basis of the value
7 received by them respectively, while the leases and MPU Agreement required them to pay on the basis of
8 the higher of the value received by them or the volume weighted average received by other MPU lessees.
9 By letters dated August 30, 1991, Conoco and OXY contended that paying royalties on the basis of the value
10 received was correct because: (1) the State had acquiesced in this method; (2) the State had failed to comply
11 with paragraph 18(h)(7) of the MPU Agreement; and (3) paragraph 18(h)(6)(c) of the MPU Agreement may
12 be inoperative because the field prices reported by other lessees in the MPU may not have been "actually
13 received" by those lessees. Until recently, this dispute ("Royalty Valuation Dispute"), which involves all
14 oil production from the beginning of production to March 31, 1994 and thereafter, had been tolled during
15 the parties' settlement negotiations.

16 8. On January 13, 1994, OXY notified the State that it was terminating the parties' tolling
17 agreement relating to the Royalty Valuation Dispute effective March 13, 1994. On January 28, 1994, the
18 State notified OXY that the State intended to determine which method in paragraph 18(h)(6) of the MPU
19 Agreement shall be used to establish royalty value and requested OXY to present any evidence and argument
20 regarding the matter. By letter dated February 28, 1994, OXY submitted written evidence and argument
21 regarding the matter. The Commissioner has yet to make his determination on the matter.

22 Miscellaneous Facts

23 9. In December of 1993, Conoco agreed to assign all of its rights, title, and interest in the MPU
24 leases and the MPU, to BP Exploration & Oil Inc. ("BP" will refer to BP Exploration & Oil Inc. and any

1 of its related persons or entities including, but not limited to, BP Exploration (Alaska) Inc.). The assignment
2 was effective 11:59 p.m. on December 31, 1993.

3 10. Conoco, OXY, and the State desire to resolve and settle: (1) all claims involved in the Royalty
4 Reduction Administrative Appeal, the Supreme Court Appeal, including the awards of cost and fees in the
5 Contract Action and the Supreme Court Appeal, and the Discovery Royalty Appeal (collectively "Appeals"),
6 and the Royalty Valuation Dispute, and (2) to provide a future valuation methodology and a future royalty
7 reduction.

8 NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby
9 acknowledged and in consideration of their mutual covenants and agreements expressed in this Agreement,
10 the parties agree as follows:

11 1.0 SETTLEMENT

12 Conoco, OXY, and the State resolve and settle all claims which have been or could have been
13 asserted in the Appeals and the Royalty Valuation Dispute for all leases in the MPU. The parties do not
14 intend to settle and resolve other claims relating to royalty obligations including, but not limited to, pipeline
15 tariff or quality bank adjustments.

16 2.0 RESOLUTION OF PAST DISPUTES

17 2.1 Offset

18 The parties agree that any amount which Conoco and OXY may owe the State as a result
19 of the Royalty Valuation Dispute from the beginning of time to the production month ending midnight
20 (A.S.T.) March 31, 1994 shall be offset against any amount which the State may owe Conoco and OXY as
21 a result of the Appeals for the same period.

22 No party shall be liable to pay any other party any sum for any act, omission, over-payment
23 or underpayment for any matter within the scope of the Mutual Release in Section 3.0 of this Agreement
24 from the beginning of time to the production month ending midnight (A.S.T.) March 31, 1994.

25 2.2 Dismissal

Upon execution of this Agreement, Conoco, OXY, and the State shall file dismissals with prejudice of the Royalty Reduction Administrative Appeal and the Discovery Royalty Appeal. The stipulation shall be in the form provided in Exhibit I to this Agreement. Each party shall bear its own costs and attorney's fees in the Appeals. The debts created by the award of attorney's fees and costs to the State in the Contract Action and the award of attorney's fees in the Supreme Court Appeal are waived and discharged.

3.0 MUTUAL RELEASE

Except as otherwise provided in this Agreement, Conoco, OXY and the State hereby mutually release, acquit and forever discharge each other, from any and all claims, liabilities, responsibilities, disputes, obligations, demands and claims for relief, known or unknown that any party now owns or holds or has at any time heretofore owned or held, against another party arising out of or in any way connected with or related to the Appeals and Royalty Valuation Dispute. In this section, Conoco, OXY and the State include their respective assignees (including BP), predecessors, successors, parents, subsidiaries, affiliates, officials, officers, directors, agents, servants, employees, and attorneys.

4.0 FUTURE ROYALTY VALUATION

4.1 Methodology

For production after March 31, 1994, the methods for calculating royalty value in paragraph 18(h)(6) of the MPU Agreement and paragraphs 15 and 16 of the MPU leases are amended as set forth in this Agreement for OXY. The amended future methodology set forth in Sections 4.1-4.5 of this Agreement shall not apply to Conoco or its assignees, including BP.

For production after March 31, 1994, the "Future ANS Valuation Methodology for January 1992 Production Forward" set forth in Article III of the ANS Royalty Litigation Settlement Agreement between Exxon Corporation and the State ("Exxon ANS Royalty Settlement Agreement"), as amended from time-to-time, shall be the exclusive method for determining the per barrel "Royalty Value" of liquid hydrocarbons allocated to OXY from the MPU leases. For purposes of this Agreement, the term "liquid

hydrocarbons includes all hydrocarbons delivered to a LACT meter in liquid form, including what has been or may be described variously as oil, condensate, scrubber liquids, gas liquids, natural gas liquids, or NGLs. OXY's monthly per barrel Royalty Value for all liquid hydrocarbons from the MPU leases shall be the Royalty Value by Field from the Kuparuk River Unit computed under the Exxon ANS Royalty Settlement Agreement for West Coast placements, adjusted for the MPU quality differential, and the Milne Point and Kuparuk pipeline tariffs. Exhibit 2 is a hypothetical calculation of OXY's Royalty Value for the production month of January of 1994 as if the methodology had been in effect for that month. Attachment 1 of Exhibit 2 is the actual royalty report for January of 1994 showing the calculation by Exxon of its Kuparuk River Unit royalty value. Exxon's royalty value for the Kuparuk River Unit is found on Attachment 1 at the intersection of the horizontal line labelled "crude" and column "h". Exxon's royalty value for the Kuparuk River Unit from Attachment 1 of Exhibit 2 is \$6.560 per barrel for the production month of January of 1994. Adjusted for the MPU, OXY's illustrative Royalty Value for the MPU is \$5.417 per barrel for the production month of January of 1994 as shown on Exhibit 2.

OXY and the State agree that it is both appropriate and reasonable to use the formula set forth in the Exxon ANS Royalty Settlement Agreement as adjusted for the Milne Point quality differential, and the Milne Point and Kuparuk pipeline tariffs, to determine OXY's royalty-in-value obligation. Therefore, OXY agrees to make, and the State agrees to accept in full satisfaction of OXY's royalty-in-value obligation, payments based exclusively upon the formula set forth in the Exxon ANS Royalty Settlement Agreement as adjusted for applicable quality differentials and pipeline tariffs.

4.2 Estimated Reports

The parties recognize that agreeing to use the Royalty Value from the Exxon ANS Royalty Settlement Agreement will make it impossible for OXY to calculate precisely its royalty obligation in the time required by the applicable lease terms. Because of that event, OXY must file estimated reports or take other action consistent with the applicable lease and unit agreement terms to ensure that its royalties are as accurately and timely paid as possible. Nothing in this Agreement relieves OXY of its obligation to correct

any royalty report which is filed incorrectly even if the error is due to an error by Exxon; provided, however, that OXY shall in no event be subject to any forfeiture (other than payment of interest) for failure to make timely or adequate payment where such failure results from OXY's lack of timely, complete or accurate information from the State whether attributable to error by Exxon or otherwise.

4.2.1 Exxon West Coast Deliveries

Within 10 days of receipt of Exxon's royalty reports, the State will provide OXY copies of royalty reports and amended royalty reports filed by Exxon for the Kuparuk River Unit. OXY must then revise its estimated report, pay any additional royalties due plus interest or take a credit plus interest, and submit the revision when its next royalty report is due.

4.2.2 Exxon Non-West Coast Deliveries

If Exxon reports a Royalty Value for oil delivered to destination markets other than the West Coast and disclosure to OXY of Exxon's West Coast Royalty Value is prohibited by law or by the confidentiality provisions of the Exxon ANS Royalty Settlement Agreement, then the following procedure shall apply:

a) OXY must file its estimated royalty report as provided above in this subparagraph 4.2.

b) Within 10 days of receipt of Exxon's royalty reports, the State will provide OXY a "blended" Royalty Value (which shall be defined as the volume weighted average Royalty Value for all of Exxon's deliveries to the various destination markets from the Kuparuk River Unit based on Exxon's royalty reports). The State will not provide OXY copies of Exxon's royalty reports.

c) If Exxon's blended Royalty Value, adjusted for the MPU quality differential and the Milne Point and Kuparuk pipeline tariffs, is greater than OXY's estimated Royalty Value, then OXY must revise its estimated report, pay any additional royalties due plus interest, and submit a revised report when its next royalty report is due. OXY's revised Royalty Value must equal or exceed Exxon's blended Royalty Value, adjusted for the MPU differential and the Milne Point and Kuparuk pipeline tariff.

d) Other than to correct mistakes made by OXY itself, to adjust the Royalty Value because of tariffs or quality bank adjustments, or to recalculate the Royalty Value as set forth in subparagraph 4.3, no additional revisions need be made to OXY's royalty reports until after the beginning of the fourth calendar year following the production month in question.

e) After the beginning of the fourth calendar year following the production month in question, the State shall provide OXY with Exxon's Royalty Value from the Kuparuk River Unit for West Coast placements for each month's production in the production year in question, and a recalculation of OXY's royalty obligation, plus interest, for each month of the production year in question based upon Exxon's royalty payments, including any adjustments. For example, in January of 1998, the State shall provide OXY with the Exxon Royalty Value from the Kuparuk River Unit for West Coast placements for each production month in 1994, and a recalculation of OXY's royalty obligation, plus interest, for each production month in 1994.

f) OXY must then revise its last filed royalty reports for the production months in question when its next royalty report is due. If OXY owes the State additional royalties as a result of the recalculation, OXY must pay the recalculation plus interest when its next royalty report is due. If the State owes OXY a refund of royalties as a result of the recalculation, the State must pay OXY, plus interest, by credit to OXY's next and, if necessary, succeeding royalty returns).

g) OXY shall have the right, upon reasonable notice and with reasonable frequency, to audit all information in the possession of the State used to determine OXY's royalty obligations except information which cannot be disclosed by law or under the confidentiality provisions of Exxon's ANS Royalty Settlement Agreement. In addition, at any time after the beginning of the fourth calendar year and until the end of the sixth calendar year following the month in question (e.g., beginning January 1, 1998 and ending December 31, 2000, information for January 1994 and all other months of 1994 will be available to OXY), OXY shall have the right to audit per barrel transportation costs for Exxon (but not any underlying, detailed confidential data) of any applicable transportation costs between the Valdez terminus of TAPS and

1 the locations at which destination values were determined. In the event that the information necessary for
2 the State to comply with Exxon's ANS Royalty Settlement Agreement or for OXY to audit transportation
3 costs cannot be made available to OXY by law or under the confidentiality provisions of the Exxon ANS
4 Royalty Settlement Agreement, the State and OXY will cooperate to arrange an exchange of the information
5 (e.g., through a third party) which satisfies the State's obligations and OXY's rights to audit without
6 violating the law or confidentiality provisions of the Exxon ANS Royalty Settlement Agreement.

7 It is the intent of the parties to make available for audit by OXY: (1) all data needed to audit
8 the determination of applicable destination values, and (2) except for any detailed underlying confidential
9 transportation data, all other data needed to audit the determination (as applicable) of (a) per barrel values
10 at Valdez, (b) Trans Alaska Pipeline System (TAPS) and other pipeline tariffs, (c) gravity and other quality
11 adjustments, (d) loss allowances upstream of Valdez, (e) per barrel values at TAPS Pump Station No. 1, and
12 (f) field costs.

13 Nothing in this Agreement limits the State's rights under the Leases and applicable statutes and
14 regulations to audit OXY's royalty returns and to adjust prior billings to OXY.

15 4.3 Intervention

16 OXY recognizes that the amended future methodology may from time to time change as a
17 result of reopeners under the Exxon ANS Royalty Settlement Agreement.

18 This Agreement does not give OXY any independent right to intervene in any proceeding
19 involving Exxon or any other ANS Royalty Litigation defendant. OXY does not have an independent right
20 to invoke any of the provisions contained in Article IV of the Exxon ANS Royalty Settlement Agreement
21 or other similar provisions in any settlement agreement which has been or may be entered into between the
22 State and any other ANS Royalty Litigation defendant. If the royalty formula methodology set forth in the
23 Exxon ANS Royalty Settlement Agreement is modified, a corresponding modification will be made in the
24 values used to calculate OXY's royalty-in-value obligation retroactive to the production month or months
25 affected by the modification to the Exxon formula methodology.

1 The following illustration demonstrates (without limiting) how the parties intend the
2 modification procedure to work. If in March 1995, the Exxon ANS Royalty Settlement Agreement is
3 modified to increase Exxon's monthly royalty-in-value obligation commencing January 1995, the Exxon
4 modification would require recalculation of OXY's royalty-in-value obligations for the production months
5 of January 1995, February 1995 and March 1995 by substituting Exxon's modified Kuparuk River Unit
6 Royalty Value in the OXY royalty-in-value formula for these three months. The OXY royalty-in-value
7 recalculation would be made in the production month immediately following OXY's receipt of Exxon's
8 amended report based on the triggering modification (i.e., as applied to the illustration, the recalculation of
9 OXY's royalty-in-value obligation and the filing of amended royalty reports would be made in April 1995,
10 assuming OXY receives Exxon's amended report in March of 1995). In the event modification to the Exxon
11 royalty-in-value formula is made by an arbitration panel, the appropriate recalculation shall be made in the
12 production month following OXY's receipt of Exxon's amended report based on the final decision rendered
13 by the arbitration panel. The State shall be responsible for timely notifying OXY of any and all
14 modifications to or redeterminations under the State's settlement with Exxon.

15 4.4 Interest

16 The same interest rate shall apply for overpayments, underpayments and other obligations
17 arising under this Agreement. Notwithstanding AS 38.05.135(d)-(e), the applicable interest rate shall be the
18 prime rate of interest publicly announced by Bank of America, NT and SA, of San Francisco, California,
19 from time to time, and that interest shall be compounded daily.

20 4.5 RIK and RIV Election

21 For production after March 31, 1994, the State may elect to take, either in-kind or in-value,
22 all or a specified percentage or volume of its royalty interest in OXY's liquid hydrocarbon share from the
23 MPU leases by giving 90 days advance written notice of its intent to OXY. Additionally, if necessary to
24 implement this section, OXY will vote to amend the MPU Agreement and shall ask other MPU lessees to

1 agree to amend the MPU Agreement to provide for 90 days' notice. Nothing in this Section obligates OXY
2 to obtain the agreement of other MPU lessees to amend the MPU Agreement.

3 5.0 FUTURE ROYALTY REDUCTION

4 5.1 Methodology

5 For production after March 31, 1994, the royalty rate specified in the MPU Agreement and
6 ADLs 47432, 47433, 47434, 47437, 47438, 47439, 315846, and 319717 (collectively 20% Leases) is
7 expressly amended for OXY only. The royalty rate for OXY's interest in the 20% Leases is reduced from
8 twenty percent to twelve and a half percent. The royalty rate for all other OXY leases and other lessees in
9 the MPU shall remain unchanged by this Agreement, but may be changed in the future as provided for in
10 applicable statutes, regulations, and agreements. The amended future royalty rate and limitations set forth
11 in Sections 5.1-5.3 of this Agreement shall not apply to Conoco or its assignees including BP and to OXY's
12 assignees.

13 5.2 Assignment

14 The right to pay royalty based upon the methodology set out in Section 5.1 of this
15 Agreement cannot be sold, assigned, cross-assigned, exchanged, or in any way transferred (collectively
16 "Transfers"). If OXY Transfers in any manner any portion of its respective interests in the 20% Leases,
17 the Transferee will have the obligation to pay royalty on the interest Transferred at the rate of twenty percent
18 of the Royalty Value of gross production, as value is defined in Section 4.1.

19 5.3 Limits on Future Royalty Reduction

20 Notwithstanding paragraph 18(h)(8) of the MPU Agreement and any otherwise applicable
21 law, OXY cannot apply for any reduced royalty: (1) for any of the leases identified in Section 5.1 of this
22 Agreement, during the remaining life of the MPU; or (2) for any other liquid hydrocarbon production from
23 the MPU, for five years from the effective date of this Agreement.

24 6.0 FUTURE DISCOVERY ROYALTY

1 As provided in Section 3.0 of this Agreement, Conoco and OXY release, acquit, and forever
2 discharge the State from any past (retroactive) and future (prospective) discovery royalty relief respecting
3 the formation variously known as the Shallow Oil Sands, West Sak Sands, and Schrader Bluff Formation
4 at the MPU. As provided in Section 7.0 of this Agreement, Conoco and OXY warrant, each as to their
5 respective and separate interests in the MPU as of the effective date of this Agreement, to the State that they
6 have not assigned or transferred any portion of their discovery royalty claim to BP and that a release from
7 BP need not be obtained for a complete (past and future) settlement of the Discovery Royalty Appeal.

8 **7.0 INDEMNIFICATION AND WARRANTIES**

9 Conoco, OXY (as to their own respective and separate interests in the MPU as of the effective date
10 of this Agreement) and the State hereby warrant that they know of no other persons or entities from whom
11 releases should be obtained for any of the claims, demands or causes of action settled by this Agreement and
12 that they (as to their own respective and separate interests in the MPU as of the effective date of this
13 Agreement) have not previously assigned or transferred, or purported to assign or transfer to any person or
14 entity, any of these claims, demands or causes of action. Conoco and OXY (as to their own respective and
15 separate interests in the MPU as of the effective date of this Agreement) specifically agree that they have
16 not previously assigned or transferred to BP any past or future portion of the Discovery Royalty Appeal.
17 Each party agrees to hold each other harmless from any and all liability, damages and costs incurred,
18 including reasonable actual attorney fees if any other person or entity hereafter claims ownership or the right
19 to prosecute the indemnifying party's separate and respective interest as of the effective date of this
20 Agreement in any of the claims, demands or causes of action settled by this Agreement.

21 **8.0 NO ADMISSION OF LIABILITY**

22 Each of the parties acknowledges that this Agreement is solely for the purpose of settling disputed
23 claims and that none of the parties hereby released admits any liability for, responsibility for, or the merits
24 of any claims asserted by any other party.

25 **9.0 FURTHER DOCUMENTS AND ACTS**

1 Each party agrees, in good faith, to do all things necessary and convenient, to execute and deliver
2 such additional documents and instruments, and to perform such additional acts as may be necessary or
3 appropriate to effectuate, consummate or perform the terms and intent of this Agreement.

4 10.0 DISPUTES

5 This Agreement is made and entered into in the State of Alaska and shall be enforced under the
6 internal laws of the State of Alaska. Any dispute regarding this Agreement shall be decided by the Director
7 of the Division of Oil and Gas. Conoco and OXY shall have the right to present written evidence and
8 argument to the Director. They shall not have the right to civil litigation-type discovery or a civil-litigation
9 type trial with the right to call or cross-examine witnesses unless granted by the Director in his discretion.
10 The Director shall issue written findings together with his determination regarding the relief that should be
11 granted. Conoco and OXY shall have the right to appeal the Director's decision to the Commissioner. The
12 record on appeal shall be limited to the record presented to the Director, but Conoco and OXY shall have
13 the right to present additional written argument. The Commissioner's decision shall be subject to judicial
14 review solely through the Alaska Rules of Appellate Procedure. The sole fact that the Commissioner is a
15 signator to the Agreement or the State has a financial interest in the Agreement shall not be grounds for
16 attacking any decision made by the Commissioner under this Section.

17 11.0 GENERAL PROVISIONS

18 11.1 Binding Effect

19 Except as provided elsewhere in this Agreement, this Agreement shall be binding upon each
20 party and its representatives, successors and assigns, and shall inure to the benefit of each party and its
21 representatives, successors or assigns.

22 11.2 Acknowledgement of Non-Reliance

23 Each of the parties acknowledges and agrees that no representation or promise not expressly
24 contained in this Agreement has been made by any party or by its agents, employees, representatives or
25 attorneys. Each of the parties further acknowledges that it is not entering into this Agreement on the basis

1 of any such promise or representation expressed or implied. All of the terms and conditions of this
2 Agreement have been reflected upon without haste and no one is under a disadvantage. Each party has been
3 represented throughout all the negotiations leading up to this Agreement by counsel of its choice.

4 11.3 Attorney Fees

5 If any legal action is brought for the enforcement of this Agreement, or because of an
6 alleged dispute, breach, default or misrepresentation in connection with any of the provisions of this
7 Agreement, the successful or prevailing party or parties shall be entitled to recover reasonable actual attorney
8 fees and other costs incurred in connection with such action in addition to any other relief to which it or they
9 may be entitled.

10 11.4 Captions

11 Any captions or headings of the sections of this Agreement are solely for the convenience
12 of the parties, and are not part of this Agreement, or any provision of it.

13 11.5 Counterparts

14 This Agreement may be executed in one or more counterparts, each of which shall be
15 deemed an original, and the counterparts shall constitute but one and the same instrument which may be
16 sufficiently evidenced by one counterpart.

17 11.6 Declaration

18 Each of the parties hereby declares that the terms of this Agreement have been carefully read
19 and are fully understood and are voluntarily accepted for the purpose of making full and final compromise,
20 adjustment and settlement of any and all claims, disputed or otherwise described in Section 3.0 of this
21 Agreement.

22 11.7 Entire Agreement

23 This Agreement constitutes the entire understanding between the parties with respect to the
24 subject matter of this Agreement and supersedes all negotiations, prior discussions, and preliminary
25 agreements.

1 12.0 NOTICES

2 Any notices under this Agreement shall be given by express mail, courier, or facsimile transmission
3 to the designated representatives of the parties at the following addresses and facsimile numbers, or to such
4 new representatives, addresses, and facsimile numbers as are designated in writing by the party making a
5 change:

6 If to the State:

7 Commissioner of Natural Resources
8 400 Willoughby Avenue, Fifth Floor
9 Juneau, Alaska 99801-1724
10 Fax: (907) 586-2754

11 and

12 Director, Division of Oil and Gas
13 Box 107034
14 Anchorage, Alaska 99510-0734
15 Fax: (907) 562-5269 and 562-3852

16 If to Conoco:

17 Conoco Inc.
18 Legal Department
19 Attn: Managing Counsel
20 Exploration, Production & Natural Gas / North America Group
21 P.O. Box 4783
22 Houston, Texas 77210
23 Fax: (713) 293-3826

24 If to OXY:

25 Manager - Land, Western Region
26 OXY USA Inc.
27 P. O. Box 50250
28 Midland, Texas 79710
29 Fax: (915) 685-5931

2 EFFECTIVE as of December 30, 1993.

4 STATE OF ALASKA

6 By: _____
Commissioner of Natural Resources

8 Date Signed: _____

10 By: _____
Attorney General

12 Date Signed: _____

14
16 SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

18 _____
Notary Public, State of Alaska
20 My commission expires: _____

22
24 CONOCO INC.

26 By: _____

28 Title: _____

30 Date Signed: _____

32
34 SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

36 _____
Notary Public, State of _____
38 My commission expires: _____

40 OXY USA INC.

42 By: _____

44 Title: _____

46 Date Signed: _____
48

SUBSCRIBED AND SWORN TO before me this _____ day of _____, 1994.

2

4

6

8

10

Notary Public, State of _____
My commission expires: _____

... WORDS USE REVERSE SIDE

EFFECTIVE

as of December 30, 1993.

STATE OF ALASKA

By:

Commissioner of Natural Resources

Date Signed:

7/12/94

By:

Attorney General

Date Signed:

12 July 1994

SUBSCRIBED AND SWORN TO before me this 12th day of July, 1994.

Arthur R. Shaw

Notary Public, State of Alaska

My commission expires: 6-14-97

CONOCO INC.

By:

Title:

Date Signed:

SUBSCRIBED AND SWORN TO before me this ____ day of ____, 1994.

Notary Public, State of

My commission expires:

OXY USA INC.

By:

Title:

Date Signed:

EFFECTIVE 15 of December 30, 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: _____

By: _____
Attorney General

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

Notary Public, State of Alaska
My commission expires: _____

CONOCO INC.

By: _____

Title: _____

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this ____ day of _____, 1994.

Notary Public, State of _____
My commission expires: _____

OXY USA INC.

By: *CM Lu*

Title: *Attorney-in-fact*

Date Signed: *7/8/94*

SUBSCRIBED AND SWORN TO before me this 8th day of July, 1994.

Dennis H. H. H.
Notary Public, State of Texas
My commission expires: 12/9/96



WOODS LAM VLS COND 12

EFFECTIVE as of December 30, 1993.

STATE OF ALASKA

By: _____
Commissioner of Natural Resources

Date Signed: _____

By: _____
Attorney General

Date Signed: _____

SUBSCRIBED AND SWORN TO before me this _____ day of _____, 1994.

Notary Public, State of Alaska
My commission expires: _____

CONOCO INC.

MAG By: W T Runkle

Title: ATTORNEY IN FACT

Date Signed: 7/10/94

SUBSCRIBED AND SWORN TO before me this 19 day of JULY, 1994.

Kimberly Elizabeth Miller
Notary Public
Lafayette Parish, Louisiana
My Commission Is For Life

Kimberly Elizabeth Miller

Notary Public, State of LOUISIANA
My commission expires: for life

OXY USA INC.

By: _____

Title: _____

Date Signed: _____

ENCLOSURE 8

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
THIRD JUDICIAL DISTRICT AT ANCHORAGE

CONOCO, Inc., a Delaware
corporation and OXY USA
INC., A Delaware corporation

Appellant,

vs.

STATE OF ALASKA, DEPT.
OF NATURAL RESOURCES,

Appellee.

Nos. 1JU-91-797 Civ. and
1 JU-91-798 Civ.
(consolidated)

STIPULATION FOR DISMISSAL WITH PREJUDICE AND ORDER THEREON

Pursuant to a Settlement Agreement dated, December 30,
1993, the parties, by and through their respective counsel,
stipulate that this matter shall be dismissed with prejudice.
Each side shall bear its own costs and attorney's fees.

BRUCE M. HOTELHO
ATTORNEY GENERAL

DATED: 7.13.94

By: Patrick J. Coughlin
Patrick J. Coughlin
Assistant Attorney General

BIRCH, HORTON, BITTNER & CHEROT

DATED: 7/25/94

By: Jonathon K. Tillinghast
JUL 28 1994
CLERK OF COURT
STATE OF ALASKA, FIRST DISTRICT
AT JUNEAU

ORDER

IT IS SO ORDERED.

DATED: July 25, 1994.

By: Deputy

Hon. Larry R. Weeks
Superior Court Judge

I certify that on 7/26/94
copies of the foregoing
were sent to Jonathon K. Tillinghast
and Patrick J. Coughlin
BY: Anne Worth
Secretary to Judge Carpeneti

DEPARTMENT OF LAW
OFFICE OF THE ATTORNEY GENERAL
ANCHORAGE BRANCH
1031 W. FOURTH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501
PHONE: (907) 269-5100

ENCLOSURE 9

September 19, 1979

Mr. Felix Nigh
Conoco, Inc.
Unit Operator
Proposed Gwydyr Bay and Milna Point Units
5 Greenway Plaza East, Suite 2928
Houston, Texas 77046

Dear Mr. Nigh:

I have considered your requests for establishment of the Gwydyr Bay and Milna Point Units, and Director Tom Cook's recommendation regarding those units. As you are undoubtedly aware, these unit proposals have also produced other recommendations to me from the public and most notably from the House Interim Committee on Oil and Gas Leasing Policy, which I must also consider in making a determination that protects the best interests of the State of Alaska.

Review of all the facts and recommendations before me has convinced me that the facts as they exist today make it contrary to the public interest to approve the units as proposed. By the same token, principles of equity and fair expectations clearly indicate that simple rejection of the units, which would result in expiration of most existing leases, is similarly not in the public interest, even though it has been recommended by the legislative committee.

The arguments against approval of these units as proposed center around three points. First, the fact that both statutory and regulatory standards for oil and gas leases have changed in the past 10 years, is clear to all. Second, it is equally clear that a committee of the Alaska Legislature desires to deal much more specifically than is presently the case with unitization principles and procedures, and would prefer that no open-ended units are approved pending such consideration. While the interim committee cannot speak for the entire legislature, it is obvious that the committee reflects the sentiment of a definite segment of the State's population. Third, the economics of oil and gas leasing have changed so drastically within the past ten years that in order to effectively protect the State's interest, certain changes in the leases are necessary.

645.14

Mr. Felix Nigh

-2-

September 19, 1979

Accordingly, I suggest it would be both in the State's interest and in your interest if we agreed upon a two-year unit approval, with some modifications to leases that would otherwise expire.

-In order to approve the Gaydyr Bay and Milne Point Units for this time period, I am exercising my authority under AS 38.05.180 and Section 32 of the lease in requesting your consent for the following changes, which I find necessary and proper to secure protection of the public interest:

1. Increase annual rental and minimum royalty payments to the present standard of \$3.00 per acre, as enacted in AS 38.05.180(n); all leases proposed for inclusion in the units will conform to this standard except those presently held by their own terms.
2. Increase royalty share to one-fifth (20%), which is our present minimum standard, as used in the recent Copper River Basin lease sale. This higher royalty will apply to all leases proposed for inclusion in the units except those presently held by their own terms.
3. Apply the present standard of lease stipulations, which are attached. These generally reflect the stipulations which we will use in the upcoming Beaufort Sea lease sale. All leases in the units will be subject to these stipulations.
4. Modify the existing leases to eliminate the problem presently under litigation in State v. Amerada Hess, et al. This modification will apply to all leases in the units.

The drilling requirements set out in Sections 9 and 10 of the proposed Gaydyr Bay and Milne Point Unit Agreements will be accepted in their currently proposed form.

Specific language to incorporate these changes into the proposed unit agreement is attached.

I am sure you will agree that upgrading your present leases to today's standards is a reasonable request in exchange for a two-year extension of the lease term, in light of major changes in circumstances since 1969. I sincerely hope we can reach agreement on this matter before expiration of the affected leases.

Sincerely,

Robert E. LaResche
Commissioner

REL:blg

ENCLOSURE 10

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

POUCH 7034
ANCHORAGE, ALASKA 99510

October 9, 1984

H. D. Haley
Conoco, Inc.
2525 C Street, Suite 100
Anchorage, Alaska 99503

**Re: Royalty reduction request
for Milne Point.**

Dear Mr. Haley:

This letter responds to your October 4, 1983 letter in which Conoco Inc. requested a royalty reduction for the following State of Alaska leases: ADL 47432, ADL 47433, ADL 47434, ADL 47437, ADL 47438, ADL 47439, ADL 315846, and ADL 319717 ("the Conoco leases"). Due to the legal, economic and geologic considerations stated below, the Division of Oil and Gas has determined that Conoco's request must be denied.

Although we can appreciate the difficulties Conoco anticipates in profitably developing Milne Point production, the division is statutorily prohibited from granting the requested royalty reduction. AS 38.05.180(j) precludes the division from granting a royalty reduction until there has been two years' initial production from the field. In Conoco's request, you relied on certain contractual provisions as support for the requested royalty reduction. However, the Department of Law has advised us that those contractual provisions were mooted by the 1979 unit agreement covering the Conoco leases, and that the statutory restriction is applicable. Under the pertinent geologic and economic considerations, Milne Point must be regarded as a separate field for royalty reduction purposes. Since there has not been two years' initial production from the Milne Point Field, the division is statutorily prohibited from granting Conoco a royalty reduction. A more detailed discussion of these conclusions follows.

Inclosure 10

EXHIBIT 1

A. Legal Considerations

The division has considered the contractual and regulatory provisions stated in Conoco's royalty reduction request, and has determined that those contractual provisions were superseded by the September 28, 1979 "Unit Agreement for the Development and Operation of the Milne Point Unit." That unit agreement expressly provides that its terms modify Conoco's prior leases, and expressly precludes the state from granting royalty reductions for covered leases until two years' production occurs from the field in which the lease is located. In 1978 the Alaska legislature had amended the royalty reduction statute, AS 38.05.180(j), to require two years' initial production from the field before the commissioner of natural resources could even consider granting a royalty reduction request. The unit agreement requirement brought the Conoco leases into conformity with that amended statute. Neither the statute nor the unit agreement provisions need be belabored here since they are treated at length in the April 24, 1984 memorandum of advice from Assistant Attorney General Bonnie Thie to the division. (Attached as Exhibit A)

The threshold questions are whether the Milne Point Leases are located in a discrete field, and if so, whether there has been two years' initial production from the field in which the Milne Point leases are located. Although the division has no statutory definition of "field" for royalty reduction purposes, the memorandum of advice states three possible geologic definitions of field: (1) a common source of supply, pool or reservoir; (2) multiple reservoirs vertically separated; or (3) multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The memorandum of advice further delineates the legislative policies to be considered in applying those geologic definitions: (1) the policy of reducing royalties when necessary to ensure that economic pressures would not cause an oil and gas field to be prematurely abandoned as production begins to decline, and (2) the countervailing policy of preventing speculative royalty bidding, in which a firm would make an unrealistically high bid to secure a lease while counting on a subsequent royalty reduction to make development of the lease profitable. The memorandum of advice concludes that the division must apply its expertise to those geologic, economic, and policy issues to determine both the scope of the Milne Point Field and whether two years' production has occurred from the Milne Point Field.

B. Geologic Considerations

Conoco's counsel has suggested that for purposes of Conoco's royalty reduction request, the Milne Point leases be considered as part of the Kuparuk Field. However, under each of the three geologic definitions of field identified in the memorandum of advice as being most pertinent to royalty reductions, Conoco's Milne Point Unit constitutes a field separate from the Kuparuk Field. A technical review of the subsurface geology, regional stratigraphic data, and the reservoir characteristics of the productive formation in the Kuparuk and Milne Point Units confirms that the Milne Point leases will produce from an accumulation separate and distinct from that which is productive in the Kuparuk River Unit.

Petroleum occurs in several stratigraphic intervals in both the Milne Point Unit and the Kuparuk River Unit. However, petroleum production from the Kuparuk River Unit to date in commercial quantities has been limited to production from the Kuparuk Formation, as that formation was formalized by George J. Carman and Peter Hardwick, Geology and Regional Setting of Kuparuk Oil Field, Alaska, 1983 AAPG Bulletin, V. 67, p. 1014-31. With the exception of a pilot project in the stratigraphically higher West Sak Sands, none of the other stratigraphic intervals known to contain petroleum regionally, the Sadlerochit Formation, the Lisburne Formation and the Kekikruk Formation, have yet produced hydrocarbons in commercial quantities in either the Kuparuk or the Milne Point areas. Since Conoco proposes to develop and produce only Kuparuk Formation reserves in the Milne Point Unit, only the stratigraphic setting and structural configuration of the Kuparuk Formation itself need be considered.

Carman and Hardwick informally subdivided the Kuparuk Formation's stratigraphic sequence into an upper and a lower member. They further divided the lower member into the "A" and "B" units, and the upper member into the "C" and "D" units (see attached Figure 1). The Kuparuk Formation is thought to have been deposited in a shallow marine environment, and its various stratigraphic units are generally laterally continuous. However, reservoir quality unit "C" is absent at Milne Point. Under Conoco's current proposal, the Milne Point Unit will produce only from the "A" and "B" units, while the Kuparuk River unit produces predominantly from the "A" and "C" units.

Three possible geologic definitions of "field" are most pertinent for royalty reduction purposes. "Field" may refer (1) to a common source or supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs like those created in a

depositional environment such as a river delta. In reviewing whether Conoco's leases lie within the same field as the Kuparuk River Unit leases, the division considered each of these possible definitions. The second and third definitions may be briefly dismissed since they do not apply to the geographic and geologic parameters of the Kuparuk Formation in the Milne Point and Kuparuk River Unit areas. The Kuparuk River Unit and the Milne Point Unit could not be regarded as one field under the second definition, that of vertically separated reservoirs, because the two units do not share a common surface area. Although the units are both located over the Kuparuk Formation, they are geographically separated, with the Milne Point Unit located to the northeast of the Kuparuk River Unit. Nor could the two areas be described as comprising the same field under the third definition, that of multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The Kuparuk Formation consists of generally laterally-continuous units deposited in a shallow marine environment.

The "A" unit of the Kuparuk Formation is potentially productive in both the Kuparuk River and Milne Point Unit areas, making the first definition of field, a common source of supply, pool or reservoir, possibly applicable. However, to satisfy that definition, structural and stratigraphic continuity must exist between the Kuparuk River and Milne Point Unit accumulations. If either a structural barrier, due to folding or faulting, or a stratigraphic barrier, due to the absence of a continuous permeable bed, exists between the two accumulations, they can not be described as the same field.

Published data confirm the existence of a discrete Milne Point Field, structurally distinct from the Kuparuk River Field. The Carman and Hardwick study describes a structural dip closure along the northern and eastern flanks of the Kuparuk Field. The lower half of attached Figure 2, taken from that study, demonstrates how a combination of folding and faulting have resulted in a separate Kuparuk Field hydrocarbon accumulation. The northeast border of the Kuparuk Field is delineated by an oil-water contact located southwest of the Milne Point Unit. The top half of Figure 2 shows the Social Simpson Lagoon 32-14 Well (dry hole) and the abandoned ARCO West Sak 25 Well, with the oil-water contact of the Kuparuk Field located to the southwest. Based on data from those wells, the Milne Point Field oil-water contact appears to lie to the northeast. The oil-water contact on the northeast side of the Kuparuk Field is also shown on the attached Figure 3, a structure contour map submitted by ARCO

Alaska, Inc., operator of the Kuparuk River Unit. On this map, the oil-water contact is placed at approximately minus 6450 feet subsea, similar to the location shown in Figure 2.

Other public and confidential data on file with the division similarly demonstrate structural discontinuity between the Kuparuk and Milne Point accumulations. Separate oil-water contacts exist for each field, with the drainage pattern between the two fields being northeastward in the case of the southwestern edge of the Milne Point Field, and southwestward in the case of the northeastern edge of the Kuparuk Field. There exists an intervening structural discontinuity between the areas so extensive as to prevent a common source of supply, pool, or reservoir. Thus, the Kuparuk River and Milne Point Units contain two separate and distinct fields, even though the "A" unit is potentially productive in both areas.

Available geological data support the conclusion that the Milne Point Field and the Kuparuk Field contain separate accumulations of hydrocarbons. Under the relevant geologic considerations, the Conoco Milne Point Unit leases are not within the same field as the Kuparuk River Unit leases.

C. Economic Considerations

The determination of whether Conoco's Milne Point Unit Leases could at this time legally receive a royalty reduction must be made in light of legislative intent to prevent premature abandonment of producing fields and to preserve the integrity of royalty bidding. Specifically, the memorandum of advice instructs the division to consider "... whether the legislature's objectives will be met if there is no production history or cost data from an area linked by geology or economics to the applicant lease (e.g., shared cost, geologic and engineering data); whether reducing the royalty on oil or gas from one area produced independently of another area will prolong the production life of the other area; and whether, if there had been royalty bidding, reducing the royalty under the instant circumstances would make a sham of that bidding."

The legislative policy of preventing early abandonment of a producing field cannot be met if there is no demonstration by the applicant that the costs of continued production exceed a "reasonable" rate of return on the lessee's discounted investment. Conoco's costs to develop the Milne Point Unit leases cannot be determined directly from the costs ARCO incurred in developing the Kuparuk River Unit leases. Since the major

production from each field occurs from different horizons within the same stratigraphic interval, the formation characteristics and the anticipated producing rates can be expected to vary. In recognition of this fact, the scale of development for each field is unique to that field. The Milne Point Field reserve size is much smaller than the Kuparuk Field reserve size. Accordingly, the investment required by Conoco to fabricate and install production facilities at Milne Point is but a fraction of the costs associated with developing the Kuparuk Field. Moreover, the rates of return which may be "profitable" to ARCO or its partners in the Kuparuk Field provide little, if any, indication of what may be profitable to Conoco and the other working interest owners in the Milne Point Field.

(5) Whether Conoco can operate the Milne Point Field profitably can only be demonstrated retrospectively after Conoco installs production and transportation facilities and commences production at Milne Point. Conoco can speculate as to its future successes or failures, but the legislature clearly contemplated that the department would consider more than the lessee's prognostications (based on a third party's performance in dissimilar circumstances) in determining whether or not to grant a royalty reduction. Similarly, absent a history of production, there is no basis for making an argument that reducing the royalty rate of the Kuparuk leases would prolong the production life of the Milne Point leases, or vice versa.

st The legislative policy against allowing royalty reductions in circumstances where the royalty reduction would make a sham of royalty bidding would also be contravened if the division granted Conoco's request. To grant the requested royalty reduction despite Conoco's lack of sufficient production and cost data would make a sham of royalty bidding, because, in essence, Conoco did "bid" the 20 percent royalty rates for those leases for which it is now requesting a reduction. The leases in question were nearing the expiration of their primary terms in 1979 when Conoco requested that they be combined to establish the Milne Point Unit, thus extending their primary term and enabling Conoco and its partners to pursue a delineation drilling program. Each of the original leases provided for a royalty rate of 12.5 percent. As one of the conditions of committing those leases which would not otherwise have been held by their own terms, former Commissioner of Natural Resources LeResche increased the lease royalty obligations to 20 percent. Conoco and all the other potential working interest owners had the option at that time to refuse the royalty increase and to allow the leases to expire. ARCO, for example, chose not to join the unit as a consequence of this requirement. Conoco, however, agreed both to

the royalty increase and to other modifications of the original lease terms. Conoco then formed the Milne Point Unit and began an aggressive delineation and development program.

not likely!

By agreeing to the increased royalties imposed as a condition to the lease term extensions, Conoco was allowed to retain what were then suspected to be extremely valuable leases without having to compete openly with other knowledgeable companies for that privilege. In 1979, two of the leases proposed for commitment to the Milne Point Unit contained wells certified by the department as capable of producing in paying quantities. Had Conoco allowed the Milne Point leases to expire, the department would have reoffered the leases, presumably under a royalty or net profit share bidding system or with a higher fixed royalty, and Conoco would have been forced to compete with other potential lessees to acquire the new leases. Conoco agreed to the increased royalty with full knowledge of the commerciality of the certified wells and with perhaps the best knowledge then available of the development requirements for the reservoirs. In light of these circumstances, it would seem both unfair to other potential lessees and irresponsible on behalf of the department to grant the requested royalty reduction without an unequivocal showing by Conoco that Milne Point development will not be economically feasible absent a royalty reduction. This showing can only be made when there are sufficient production and cost data for the department to evaluate.

D. Conclusion

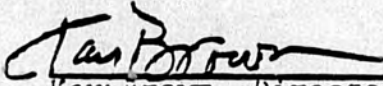
Both the economic and the geologic considerations pertinent to the division's evaluation of Conoco's royalty reduction request show the existence of a Milne Point Field that is discrete from the Kuparuk Field for royalty reduction purposes. Conoco accepted the current 20 percent royalty in order to retain its Milne Point leases, and the profitability of Conoco's Milne Point development cannot be determined by reviewing Kuparuk Field development costs. To grant Conoco a royalty reduction request at this time would thus violate the legislative policy against speculative royalty bidding and would not advance the legislative policy of preventing premature abandonment of producing fields. The underlying geology also supports the division's determination that the Milne Point Field is discrete from the Kuparuk Field, showing two distinct accumulations within a larger geologic formation.

Since the Milne Point Field is separate from the Kuparuk Field, the Commissioner is statutorily prohibited from

H. D. Haley
Conoco, Inc.

October 9, 1938
Page

granting Conoco's royalty reduction request until after two years' initial production from the Milne Point Field itself. The division's decision is based on a consideration of the currently available economic and geologic data. If Conoco wishes to pursue its royalty reduction request further, it is, of course, entitled to apply formally for royalty reduction under 11 AAC 83.185. Upon Conoco's fulfillment of the requirements of subsection .185(a), the Commissioner will schedule a public hearing at which Conoco can present further information and evidence. If you have any questions concerning this letter, please feel free to contact me.


Ray Brown, Director
Division of Oil and Gas

Enclosures

ENCLOSURE II

STAT
DEPARTMENT

DEL. 2-5-96 LOCATION Oil: Gas
FROM 1010 W 13th St LOCATION
TELEPHONE/TELECOM # _____ TOTAL NUMBER OF PAGES 5
TRANSMITTING CH/SPEED _____ DATE 2-5-96 TIME _____
PHONE FOR PROBLEMS/NAME/NUMBER 515-240
COMMENTS _____

February 5, 1986

Mr. John R. Kemp
Manager of Alaskan Operations
Conoco Inc.
3201 C Street, Suite 200
Anchorage, AK 99501

Re: Milne Point Unit Agreement

Dear Mr. Kemp:

Since your company filed its applications for royalty relief for the Milne Point Unit on November 4, 1985, we have discussed the issues involved on a number of occasions. I am aware of your strong perception that royalty relief is essential for further development and continued production of the Milne Point field. I am writing to suggest an alternative to the proposals presented in your royalty relief applications; our proposal would entail a royalty alteration and Conoco's guarantee for payment as opposed to a royalty reduction.

The State is very much interested in promoting development and production of marginal oil and gas fields in Alaska. However, despite any marginal nature of operations at Milne Point, my review and analysis of your applications so far have shown no clear statutory authority for granting Conoco a simple and straightforward reduction in royalty at this time.

For example, you requested that I reconsider the State's 1979 decision to condition unitization of the Milne Point field on an increase of the royalty on the Conoco leases to twenty percent. This would require me to waive a regulation which limits reconsideration to a thirty-day period following the initial decision. My interpretation of the authority cited in your application indicates that I am empowered to waive that regulation only when the interests of justice require the waiver. I would not be prepared to make that determination until after conducting a thorough review of both the entire set of circumstances of the ensuing unitization decision and the unit activities since that time.

Enclosure 11

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Over the life of the field, equivalent or greater overall royalty payments will accrue to the State as a result of the royalty alteration I am proposing. However, the change also should give Conoco strong encouragement to further develop

7

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5. It is understood that this royalty alteration, if approved, would not preclude Conoco or any of its leasehold partners from making future applications for royalty reduction or alteration. If such application was filed by Conoco and approved by the State, the specific royalty guarantee made part of this agreement would terminate as to production prospective to the effective date of any new agreement.

ENCLOSURE 12

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

400 WILLOUGHBY AVE.
JUNEAU, ALASKA 99801-1739
PHONE: (907) 465-2400

April 29, 1987

Mr. Tom Painter
Division Manager
Conoco, Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

Dear Mr. Painter:

As you requested in your April 20, 1987 letter to me, I am writing to inform you of my decision regarding whether the department has the statutory authority to grant a reduction in its royalty on production from the Milne Point Unit in November, 1987.

My staff and I have reviewed both the applicable statutes and the history of production at the Milne Point field carefully. In addition, we have conferred with Assistant Attorney General Steve Porter who has conducted a review of the legislative history, the statutes and the case law on our behalf. Based upon that review, I have concluded that I do not have the authority to approve a request to reduce royalty rates until after two years of production from the Milne Point Unit has occurred.

Although November, 1987 represents the two-year anniversary of the commencement of production from the Milne Point Unit, two years of initial production will not have occurred by that time. My reading of the statutes confirms that there must be two years of actual production to form the basis for the economic review which must precede and support any decision to reduce the royalty rate for a producing field. Thus, the two-year period of initial production for the Milne Point Unit is tolled during the period production is suspended, as is currently the case.

Staff from the Division of Oil and Gas concur with Conoco's economic assessment of the losses incurred by continued production at Milne Point. They agree that had those losses been experienced over a two-year production history, a royalty reduction would be advisable. On the basis of their

ANCHORAGE DIVISION			
MAY - 7 '87			
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FIG			
AW			X
TLH			
WAP			

Enclosure 12

10-9614

Mr. Tom Painter

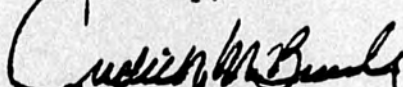
-2-

April 29, 1987

analysis I remain sympathetic to Conoco's dilemma. However, the department's options are limited under the statutes, and a royalty reduction at this time is not possible.

If you have any additional questions or are interested in discussing other options which might be available, please feel free to call me.

Sincerely,



Judith M. Brady
Commissioner

ENCLOSURE 12-A

12 A

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

State of Alaska

TO: Distribution List

DATE: September 1, 1982

FILE NO:

TELEPHONE NO:

FROM: Mary Weisenberger *mkw*
Land Management Officer
for Kay Brown
Director

SUBJECT: NORTH TRADING BAY FIELD
APPLICATION FOR ROYALTY
REDUCTION BY TEXACO
ADL 17597

Attached is an application by Texaco for a reduction of royalty to five percent (5%) on oil and gas lease ADL 17597, within the North Trading Bay Unit. The application was given to Kay at a meeting with Texaco representatives on August 25.

Texaco's application is not complete because they have not provided the information required by 11 AAC 83.665(4), which states that the application must contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease including all royalties and overriding royalties and all income from all produced minerals from the lease.

When the necessary information is supplied, you will receive a copy. The current information is being provided to enable you to make a preliminary review.

Distribution:

James Eason ✓
William Van Dyke
Sam Murray
Edward Park

Enclosure 12A

AGO 234991



LOS ANGELES DIVISION
LAND DEPARTMENT

PETROLEUM PRODUCTS

TEXACO
U.S.A.
A DIVISION OF TEXACO INC.
3350 WILSHIRE BOULEVARD
P.O. BOX 3758
LOS ANGELES, CA 90061
213-739-7100

August 20, 1982

#215699: ADL 17597
NORTH TRADING BAY FIELD - ALASKA

Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Attention: Mr. John Katz, Commissioner

Gentlemen:

Texaco Inc. respectfully requests a reduction of royalty on the Texaco-Superior Platform "A" wells located in the North Trading Bay Field in the Cook Inlet. The Alaska Statutes, 38.05.180 (j), provide for this reduction for the purpose of prolonging the economic life of an oil and/or gas field to compensate for the increasing costs in the later stages of production decline. Such is the case with the wells producing from Platform "A" on the lands within oil and gas lease ADL 17597, located in Township 10 North, Range 13 West, Seward Meridian, Sections 14, 15, 22, 23, 27, 28, 33 and 34.

The information in the attached Exhibit "A" clearly shows the revenue from the producing portion of the subject lease is insufficient to produce a reasonable rate of return with respect to our total investment in the lease.

Platform "A" was installed in April, 1968 and the drilling phase was completed in November, 1969. There are no plans at this time for any additional drilling. The initial production was about 5,000 barrels of oil per day from eight wells.

At the present time two wells are shut in (T/S #8 and #9), two wells are on Reda pumps (T/S #1 and #2), three wells are on gas lift (T/S #4, #6 and #7), and one well has been converted to a gas well (T/S #3).

The total production for the first six months of 1982 was 44,159 barrels of oil and 135,656 barrels of water. The production for July was 8,794 barrels of oil and 28,426 barrels of water.

August 20, 1982

The production for each month is as follows:

<u>MONTH</u>	<u>BBLS. OF OIL</u>	<u>BBLS. OF WATER</u>
January, 1982	12,361	26,048
February, 1982	6,125	12,951
March, 1982	2,874	13,624
April, 1982	6,448	23,381
May, 1982	9,298	34,112
June, 1982	7,053	25,540

Consequently, Texaco hereby requests that the royalty rate of 12½ percent on subject lease be reduced to a rate of 5 percent in order to attempt to prolong the economic life of this lease.

Enclosed is the filing fee of \$20.00 required by Section 11 AAC 88.105(7) and Texaco agrees to defray the costs of publishing the notice required by Section 11 AAC 83.185(b) of the leasing regulations.

Any notice relative to our application for royalty relief may be sent to Texaco Inc., 3350 Wilshire Blvd., Los Angeles, CA 90010, Attention: Division Land Manager. If there are any questions or any additional information needed, please contact the undersigned at Area Code 907, 278-9611.

Very truly yours,

TEXACO Inc.

Ethel H. Nelson

Ethel H. Nelson

Advanced Exploration Land Representative

EHN:bjs

Enclosure

EXHIBIT "A"

PLATFORM "A" COOK INLET ALASKA
COST, EARNINGS, AND PRODUCTION

<u>YEAR</u>	<u>GROSS W.I. BBLs</u>	<u>GROSS EARNINGS</u>	<u>GROSS OPR. COST</u>	<u>NET EARNINGS</u>
1978	159,466	\$1,202,298	\$ 938,174	\$264,124
1979	154,322	1,813,108	3,423,790	-1,610,682
1980*	136,212	1,711,176	1,864,502	- 153,326
1981*	120,218	3,426,298	2,709,098	717,200
1982* (6 mos.)	45,148	1,403,520	1,688,122	- 284,602

*This data includes Windfall Profits Tax

BJC
JM5/as
8-20-82

AGU 234 994

ENCLOSURE 13



BP EXPLORATION
Exploration Department

RECEIVED

DEC 08 1994

DIVISION OF OIL & GAS

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-6111

December 6, 1994

Mr. James E. Eason, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3901 C Street, Suite 1380
Anchorage, AK 99502

Subject: Badami Unitization

Dear Mr. Eason:

Further to our meeting with you on November 29, 1994, BP wishes to express for the record its utmost disappointment that we were, jointly, unable to identify an appropriate way forward to unitize the proposed Badami development area.

We firmly believe that unitization of the Badami area is absolutely essential to moving the prospect closer to development, protect natural resources and the environment and serve the State's best interest. Hence, we were very discouraged that you expressed an unwillingness to work closely with us, in a cooperative spirit, to facilitate unitization and development in the area. We truly believed that a new relationship, between industry and the DNR, had been emerging and to this end we have been working very closely with your staff for the past 12 months. (Note: Our original unit application was submitted on January 21, 1994 and revised September 9, 1994. It was withdrawn and a new application submitted on November 18, 1994.) The dialogue to date has been very open, constructive and encouraging and we believed our latest submission to you conformed to the guidance of your department which we received on numerous occasions. We were therefore astonished when we found out that you disagreed with the fundamental issue of whether Badami should or could be unitized.

Furthermore, we fully expected to discuss and clarify questions and concerns about the specifics of the Plan of Exploration or our sliding scale royalty proposal. We did not expect to encounter such a fundamental objection after the many months of cooperation, encouragement and discussion with your staff on technical and legal issues. Based on your response we will have to take a very close look at our work program in the area and question the wisdom of progressing the project at this time, while the DNR Director appears to be in the mode of discouraging prudent development. In the interim we will expand and clarify our arguments supporting formation of the Badami Unit even though you

Letter - J. Eason, DNR
Re: Badami Unitization
December 6, 1994
Page 2 of 2

offered no encouragement and thought there would be a small chance of gaining your support.

We remain convinced of the mutual benefit in pursuing Badami unitization and hope that you will see the benefits of working this issue jointly, to help us find a way to remove uncertainty from the lessor/lessee relationship. If you have any questions concerning this letter or wish to suggest a way forward, please call me at 564-5989.

Yours sincerely,

E.P. Zelnick, Jr. for T.J. Obeney
T.J. Obeney
Manager, New Developments, Alaska

TJO:lbs.

ENCLOSURE 14

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE (907) 787-2553

December 9, 1994

Mr. T. J. Obeney
Manager, New Developments, Alaska
B.P. Exploration (Alaska) Inc.
900 East Benson Boulevard
P. O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Obeney:

I am responding to your December 6, 1994 letter regarding the proposed Badami Unit. In all honesty, I find it difficult to know just where to begin. While short on specific, constructive responses to the questions I posed during our recent meeting, your letter is long on *ad hominem* attacks and mischaracterizations of my position. To the extent that those may have been occasioned by your misunderstanding either my comments regarding the proposed application, my requests of you for further justification of your proposal or my commitment to work with you toward development of Badami, I will restate them for the record.

First, I think we can both agree that a determination of whether to voluntarily unitize state leases depends upon an affirmative finding that to do so is in the state's best interest. Also, you and I both know that there are statutory and regulatory standards which guide the department's evaluation of a proposal to unitize. Just saying that it is in the state's best interest does not make it so. Against that backdrop of common understanding, I began our discussion last week by saying that, as a technical matter, I did not believe the specific factual circumstances of the Badami Unit fit the conclusory affirmation of benefits which B.P. cited in its application.

For examples, we discussed certain of the criteria of 11 AAC 83.303. While B.P.'s application makes conclusory statements about how the state's interest with respect to these criteria is enhanced, I pointed out that the facts do not seem to support the statements. Since there is no diverse ownership interest, for example, I noted that it would be difficult to make a written finding that unitization prevents competitive capture of the resource, reduces duplication of activities or facilities or minimizes the overall footprint of development. B.P. makes these claims, but the facts suggest that unitization, as opposed to lease operations, will not provide greater benefits, given that, in fact, no diverse ownership interests exist.

Enclosure 14

We went through several similar examples of problematic areas where I explained that I simply did not see how I could make the affirmative best interest findings required by law. However, rather than rejecting the application out of hand, as your letter would seem to suggest I did, I asked you to review my specific concerns with B.P.'s attorneys, and to provide a written response to them. I thought you had agreed to provide that response. The comments in your letter that "...in the interim we will expand and clarify our arguments supporting formation of the Badami Unit..." seem to confirm that this is still your intent.

We also talked about B.P.'s proposed Five Year Unit Plan of Exploration and the requested amendment to the royalty terms of the leases which are proposed to be unitized. I want to address both of these issues separately because each deserves a detailed response so that you understand the basis of my concerns.

First, as to the Plan of Exploration. In my view, what B.P. has actually proposed is a plan of non-exploration. In your letter you claim that "...We believe that unitization of the Badami area is absolutely essential to moving the prospect closer to development, protect natural resources and the environment and serve the State's best interest." (emphasis mine). One of the fundamental questions facing both B.P. and the state at this juncture is "what is the Badami development area?" The significance of that question is really at the heart of any determination of how the state's interests would be affected by its agreement with the terms B.P. proposes in its application.

Specifically, two wells have been drilled to date—one each on two adjoining leases in the area proposed to be encompassed by the Badami Unit. Both of those wells, Badami 1 and Badami 2, have been certified as capable of producing in paying quantities by the department. Based upon the results of those wells, B.P. has identified a rather compact area in which to focus its efforts to determine whether the discovery can be commercially produced. While I would not disagree with you over whether this relatively small area constitutes the "Badami Development Area," the same thing cannot be said of the vastly larger area which B.P. proposes to unitize.

In addition to the two leases upon which the discovery wells were drilled, B.P. also proposes to unitize 10 adjoining leases encompassing almost 40,000 acres. More than half of those lease are scheduled to expire in either 1995 or 1996, and although each carried a primary term of ten years, they have yet to be explored. Unitization, under the terms you have proposed, would extend to B.P. a potentially very valuable property right in these leases for a minimum additional term of five years. Yet, B.P. is unwilling to make specific commitments to explore any of these leases during the Plan of Exploration period.

As I said during our meeting, I can fully understand B.P.'s desire to secure what essentially amounts to a five or more year option on the surrounding land without having to make a firm commitment to exploration or development of that area. What I cannot understand is B.P.'s inability to recognize that its interests and those of the state are not necessarily coincident. Your proposal requires the state

to extend to B.P. the benefits of a voluntary unit which does not provide for adequate and timely exploration and delineation of all of the unit acreage.

So, one of the points on which we obviously disagree is what constitutes an adequate exploration plan for the proposed unit. What B.P. has proposed—perhaps two wells sometime in a five year period—might be adequate if the unit area were confined to the leases which have been shown to be productive. The same plan, however, is inadequate for evaluating an area as vast as B.P. proposes to unitize.

We simply have a different view of prudent development. You characterize my reaction to B.P.'s proposed Plan of Exploration as indicative that, "...the DNR Director appears to be in the mode of discouraging prudent development...." I would suggest, alternatively, that it is my commitment to prudent development that really is the source of any disagreement. The plan you propose simply does not promote prudent development of the area proposed for unitization.

The proposed unit Plan of Exploration would, however, allow B.P. to pursue development of its core discovery area while giving it an option on other nearby lands without a concomitant obligation for their timely development. Again, I can appreciate the pressure you are under to present your management with an agreement that maximizes its options, reduces its costs and enhances its revenues. I believe that we can even agree that those goals can be harmonized with the state's interest under certain conditions. Where we disagree is in our respective views of whether the terms you have proposed achieve that end. I respectfully believe that they do not, but I remain open to discussing alternate proposals which would either reduce the unit area or expand the exploration plan to ensure prudent development of any unitized leases.

We also disagree on whether B.P.'s proposed amendment of the lease royalty provisions is either statutorily permissible in the context of unitization or, assuming for the sake of argument that it is, that it is in the state's best interest. While you characterize B.P.'s proposal as an "amendment" to the royalty terms under AS 38.05.180(p) which can be accomplished through unitization, it appears in every respect to be a royalty reduction, which I believe to be governed by the provisions of AS 38.05.180(j).

How do I get to the conclusion that the amendment constitutes a royalty reduction? The leases which B.P. proposes to unitize have a weighted average royalty of 14.7 percent. The royalty amendment B.P. proposes would substitute a sliding scale royalty with a minimum royalty of 5.0 percent and a maximum royalty of 20.0 percent. The actual royalty would be determined by the movement of a Reference Oil Price defined to be the average of the daily high and low Platts sales prices for ANS delivered on the West Coast for the month preceding the production month deflated to January, 1995 dollars.

To determine the effect of such an amendment, we applied the sliding scale formula retroactively from October 1990 through today. Its use during that period would have produced an average royalty rate

of 8.1 percent. The royalty rate would have exceeded the current weighted average royalty rate of 14.7 percent only once—and then for a short period—during the five month period coincident with the Iraqi invasion of Kuwait. Applying the formula prospectively from 1995 through 2016, using the Department of Revenue's Base Case Fall, 94 forecast, would produce an average royalty rate of 6.98 percent. Thus, based upon the past and our best estimate of the future, the formula is unlikely to yield royalty rates equivalent to the current rates.

To make matters worse from the state's perspective, B.P. proposes that the formula could never be reopened and that the Reference Oil Price be deflated monthly to January, 1995 dollars, thus taking away any "index creep" from which the state could otherwise benefit. Deflation of the royalty value, of course, begs the question of why, if the economics of the prospect work in nominal dollars (dollars-of-the-day), then shouldn't the state enjoy the benefits of inflation-affected nominal prices along with B.P.?

Aside from the fact that B.P.'s proposed royalty amendment appears to be a royalty reduction, it presents other concerns as well. First, its "need" is predicated upon the unconfirmed supposition that Badami development will not be profitable under the lease terms. However, B.P. has not yet confirmed the size of Badami—and thus at this juncture cannot know what its recoverable reserves may be. Without knowing either the reserves or their areal distribution, B.P. cannot reliably estimate its costs to develop them. And, of course, neither the state nor B.P. know what future oil prices will be. Under these circumstances, neither of us are able to determine what B.P.'s revenues will be, much less what its profits may be.

Under these circumstances, B.P.'s proposal asks the state to assume a greater share of the risks. It is obvious that the economics of any prospect from the lessee's perspective will be enhanced if the state's royalty share of production is reduced. The questions of when it is appropriate to do so and how much quantitative support is necessary to find that it is in the state's best interest remain, however. The questions loom even larger when, as here, the amended royalty formula would be insensitive to the field's profitability, would not be subject to reopeners and would be artificially deflated so as to continually raise the hurdle for increased royalty rates.

Again, I can appreciate your desire to minimize risk, enhance profitability and preserve options. However, there seems to be a fundamental imbalance in this instance where the state is being asked to adopt a royalty scheme that is both insensitive to B.P.'s profits, and which will likely, under most conceivable circumstances, result in substantial royalty reductions.

Finally, I must disagree with your characterization of our meeting last week as offering no encouragement. I pledged then, and I reaffirm now, my willingness to work with you directly to see if we can find common ground that makes sense for both parties within the framework of the statutes and the regulations. To that end, my staff and I met more than six hours this past Wednesday to develop an alternative exploration plan that we believe would assure timely evaluation of the unit area. That effort was undertaken in anticipation that the discussions between B.P. and the division

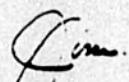
Mr. T. J. Obeney

5

December 9, 1994

would continue. Meanwhile, we will publish notice of B.P.'s unit application this Sunday, triggering the 60 day public comment period. I suggest that the way forward begin with scheduling a meeting at your earliest convenience so that we can continue our discussion.

Sincerely,


James E. Eason
Director

ENCLOSURE 15



BP EXPLORATION

Alaska Exploration & Development Department

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
PO Box 190072
Anchorage, Alaska 99519-8872
907 561 5111

January 16, 1995

State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, 13th Floor
Anchorage, AK 99503

Attn: Mr. James E. Eason, Director

Subject: Meeting January 9, 1995
Decision Criteria and Considerations
Badami Unit Application
North Slope, Alaska

Dear Mr. Eason:

Further to our meeting of January 9 and in order to address some of the concerns mentioned in your letter of December 9, 1994, we hereby submit the following in support of the Badami Unit application:

We are disappointed in your current lack of support for our sliding scale royalty proposal and are concerned about your onerous Plan of Exploration (POE) proposal. However, we believe the single most important issue, at this time, is whether the unitization of the Badami area is justifiable. Until the validity of unitization is resolved, there seems little point in discussing the Royalty or POE issues.

Therefore with the directions we received at our last meeting, we submit the following in support of unitization of the Badami area:

No Loss To The State

While, in theory, the State could construct an argument that Unitization may not enhance the State's interest, we would argue that approval of the Badami Unit would not harm the State's interest and under all reasonable scenarios would be in the State's best interest. Unitization of this area would improve the likelihood of development and accelerate the start of production. With the limited life span of

Letter - Mr. Eason
Re: Badami Unitization
January 16, 1995
Page 2 of 3

the North Slope infrastructure and TAPS, an earlier startup date would likely lead to increased recovery of reserves.

Permitting Complications And Increased Administrative Burden

Permit applications and development schedules for the Badami area have been prepared based on the assumption that the leases have been unitized. As such, a Lease Operation Permit is ready for submittal. The turn-around time for such a permit is only a few months which means it would be issued in plenty of time to enable BP to sanction the project in time for a 1997 startup. In the absence of a Unit, Tidelands permits would be required for each lease. Such permitting would be an additional administrative burden to the State and BP and would likely take a year or so to acquire such permits. This would delay sanction and production startup, as stated above. project delay could lead to loss reserves.

Increased Administration Costs And Reserve Loss By Lease Operations

Absent Unitization, under individual lease operations, there would be no Participating Area and no Tract Participating Factors. In the absence of the latter, production must be separately measured by lease for the payment of royalty. Separate measurement requires multiple separation and metering trains, one for each lease instead of a single integrated train. There would be substantial costs and economic loss under such a scenario. Indeed, the higher costs would most certainly make the project, which is already marginal, uneconomic and undevelopable. Operating costs would also be higher leading to an earlier abandonment and reserve loss. Increased facilities would also be required resulting in an enlarged development footprint and environmental impact. Increased facilities require greater manpower to operate and maintain which would increase aviation, road traffic and camp requirements. Each of these carries an incremental environmental effect. Even in the instance where the State agrees to allow production measurement by allocation, based test data, there are increased administrative costs by BP and the State as well as increased capital costs for testing facilities and increased operating costs for operations. Any operating cost increase carries an associated reserve loss:

Each of these items leads to the inevitable conclusion that Unitization of Badami is in the best interests of both the State and BP.

Finally, we would like to express our concern over the State's position that the lack of diverse ownership at Badami weakens the justification for formation of a Unit. As you know we have been working with our partner, Petrofin, to eliminate or reduce potential future conflicts by attempting to align our interests in the leases in and around the first two Badami wells. Now it appears that this

Letter - Mr. Eason
Re: Badami Unitization
January 16, 1995
Page 3 of 3

desirable activity has created a "catch-22" situation. An activity aimed at enhancing the likelihood of development is interpreted by the State as a reason to argue against the necessity of forming a Unit. The absence of a Unit at Badami can only introduce uncertainties which lead to the potential for conflict and delay in development. This will result in economic loss to all the parties. Further, if the current alignment between the owners decays because of the absence of a Unit, or leases change hands because of lease expiration, we will find ourselves faced with the potential for competitive developments. This, in-turn, will require the formation of a Unit. It is reasonable therefore to conclude that all likely paths ultimately lead to the formation of a Unit, as is the case with all producing fields on the North Slope. The State would appear to gain nothing, and risk significant economic loss, by denying Unitization at Badami.

I hope these arguments encourage you to re-visit your recent letter and we can conclude the Unitization issue and move on to the other issues. If you have any questions, please call me at (907) 564-5989.

Yours sincerely,



T.J. Oberney
Manager, New Developments, Alaska

ENCLOSURE 16

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

PO BOX 107334
ANCHORAGE, ALASKA 99510-7334
PHONE: (907) 782-2553

January 20, 1995

Via Fax (564-5200) and U. S. Mail

Mr. T. J. Obeney
Manager, New Developments, Alaska
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99512-6612

Dear Mr. Obeney:

I am responding to your January 16, 1995 letter regarding our January 9, 1995 meeting to discuss BP's Badami Unit Application (application). Given that more than five weeks have passed since my December 9, 1994 letter to you identifying the application's deficiencies, the substance of your recent letter surprised me. My stated concerns regarding the substance of BP's Plan of Exploration (POE) and its proposed sliding scale royalty amendment have yet to be addressed. In fact, reading your most recent letter "cold," one would be hard pressed to imagine that I had ever written my December 9, 1994 letter, much less that we had a subsequent meeting on January 9, 1995, in which I had laid out a virtual road map, with specific alternatives, for BP's approaching unitization of the Badami prospect.

We spent more than two hours during our January 9 meeting discussing specific language and issues which I believe would cure the "justification of unitization" issues, i.e., making the facts of BP's proposal conformable with the criteria of 11 AAC 83.303. However, your letter appears simply to disregard what I had hoped were to be constructive results of that discussion. Instead of acknowledging any progress on that front, you note "...we believe the single most important issue, at this time, is whether the unitization of the Badami area is justifiable. Until the validity of unitization is resolved, there seems little point in discussing the Royalty or POE issues." (emphasis added.)

Also in our January 9th meeting, I provided BP a specific, written alternative POE, as I had promised in my December 9, 1994 letter to you. We spent a considerable amount of time explaining the basis for the proposed alternative and answering several questions which you raised. We concluded our meeting with a discussion of the basis for my belief that the division lacks the authority to amend the lease royalty terms by substituting a sliding scale royalty such as BP has proposed. As I noted in my December 9th letter, the amended application appears in every respect to be a royalty reduction which can only be accomplished through the procedures set forth in AS 38.05.180(j).

Thus, when we met on January 9th, the issues separating us were how to address (harmonize) the language of BP's application with the statutory and regulatory criteria governing unitization, how to define an appropriate POE, given the "area" BP proposes to include in the unit, and how to address BP's proposed "amendment" to the lease royalty provisions. As to the first issue, I believe we both now understand how to come to closure. As for

January 19, 1995

the two remaining substantive issues, what is an appropriate POE and whether lease royalty terms can be amended as BP has proposed, they remain unresolved.

The division has proposed changes to BP's application that will make the proposed unit technically and legally defensible, and fair to all parties. We have described in writing specific concerns about those areas where we believe the Badami Unit application to be deficient; we have provided suggested remedies. We have offered an alternative POE that would assure timely and thorough exploration of all the Badami area, not just the Badami discovery area. We have also taken the further step in our meeting on January 9, 1995 of inviting you to propose an alternative POE, i.e., a less ambitious program than our alternative, but for a smaller unit area, if you desire. BP's sole response, as conveyed in your most recent letter, seems to be "...We are disappointed in your current lack of support for our sliding scale royalty proposal and are concerned about your onerous Plan of Exploration (POE)."

I believe the state and BP can find a common interest in unitization of the Badami discovery, but only with a POE appropriate to the area proposed, and only under the leases' current royalty provisions, absent changes in the law. On this last point, you appear to be unwilling to revise your application to withdraw BP's proposed royalty amendment. In our last meeting, you even asked whether someone else sitting in my seat would make the same decision, inferring that the law may be subject to multiple interpretations. As I told you then, I still believe that it is unlikely that BP can persuade anyone else to overlook the consistent written policy of the past three administrations and the legal advice which supported that policy. However, you should make an independent judgment of the likelihood of your success in that regard. To assist you in understanding the issue from our perspective I have enclosed a number of documents for your review. These include letters by former commissioners Wunnicks and Brady, as well as former Division of Oil and Gas Director Brown, which address the department's royalty reduction authority.

In closing, I urge you to focus on the remaining issues which need to be resolved if unitization of Badami is to occur. BP's approach to date seems to be unitization under its proposed terms - or not at all. I continue to believe there are legal and technical issues which will prevent us from ever closing under those terms. However, I remain open to continuing discussions which are responsive to the concerns I have raised. Neither of us should forget, however, that the clock is ticking. The public comment period has closed, and under the provisions of 11 AAC 83.316, a written decision approving or denying BP's application must be issued no later than March 14, 1995.

Sincerely,


James E. Eason
Director

Enclosures

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STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

BILL SHEFFIELD, GOVERNOR

FOUCH M
JUNEAU, ALASKA 99811
PHONE: 907-465-2400

March 17, 1986

The Honorable Arliss Sturgulewski
Chair, Senate Resources Committee
P.O. Box V
Juneau, AK 99811

Dear Senator Sturgulewski:

The Department of Natural Resources supports SB 410, which is scheduled for a hearing today in the Senate Resources Committee. The bill would authorize the commissioner of the Department of Natural Resources under certain circumstances to reduce or revoke oil or gas royalty obligation increases made in connection with the institution or operation of a cooperative or unit plan.

The bill primarily would affect the Milne Point Unit, a small North Slope oil field which began production last fall.

Conoco, Inc., the Milne Point Unit operator, has been seeking for several years to roll back a 20% royalty on certain Milne Point leases. The royalty obligation on those leases was increased from 12.5% to 20% under an agreement required by the department in 1979 as a condition of approval of the Milne Point Unit.

As a result of an application for royalty relief filed last fall by Conoco and Milne Point Unit working interest owners Reading and Bates Petroleum Company, Champlin Petroleum Company and Cities Oil and Gas Corporation, the department has examined confidential economic, geological, geophysical and engineering data supplied by the companies. Based upon that review, the department believes that rescinding the royalty increase would encourage continued production and further development of oil reservoirs within the Milne Point Unit.

Under existing and forecasted economic conditions, there is a high likelihood that both the economic and physical recovery of oil and gas at Milne Point will not be maximized for either the companies or the state at a royalty rate of 20%. Production of oil and gas from the developed reservoir (i.e., the Kuparuk River formation) will not be maximized, and development and production of oil and gas from yet to be

AGG 1354810

March 17, 1986

developed reservoirs (i.e., the Shallow Sands - heavy oil and gas reservoirs, geologically equivalent to ARCO's West Sak-Ugnu reservoirs at Kuparuk Unit) likely will not occur at all. The companies have made a persuasive case that they cannot be reasonably assured an adequate rate of return on any future or incremental investment under the existing 20% royalty. Given the further erosion of crude oil prices since the application was filed with the state last October, it is possible that current production will be halted if the royalty rate on the leases remains at 20 percent.

A careful review by staff of the data and analyses supplied by the companies confirms that, under current and expected market conditions, the companies likely will not receive an adequate rate of return on their current investments, and that future investments in the Milne Point Unit also would yield a less than satisfactory return. It is also very likely that if current conditions persist (or get worse), the field will be shut-in if the royalty remains at 20%. In addition, future development of the Milne Point Unit Shallow Sands is almost certain not to occur at a 20% royalty.

A reduction in the royalty rate from 20% to 12.5% would result in a revenue decrease to the State of approximately \$4.5 million a year from the Milne Point Unit. (See attached fiscal note.)

The department has tried to address the need for royalty relief within the current statutory framework, and earlier this year proposed that the royalty obligation be changed (not reduced) to a 12.5% royalty and a 3% Net Profit Share in lieu of the current 20% royalty. The companies have not accepted this proposal, even though it would have the effect of an immediate reduction in the royalty obligation, and would leave open the opportunity for the companies to apply for further relief after two years of field production based on the facts and circumstances at that time.

The department has been constrained from considering an outright royalty reduction by AS 38.05.180(j), which precludes the commissioner from granting a reduction of a lease royalty "until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in that field."

The department's proposal to change the existing royalty rate was based on the authority of AS 38.05.180(p), which authorizes the commissioner to change royalty requirements of unitized leases "as the commissioner determines necessary

March 17, 1986

or proper to secure the proper protection of the public interest." Under the department's proposal, the state likely would have been compensated for the near-term revenue losses resulting from a reduction to a 12.5% royalty rate by the further receipt of revenues from the development of the Shallow Sands reservoirs at Milne Point and the application of the 15% Net Profit Share and the 12.5% royalty to that production. Revenues to the state over time likely would have been equivalent or greater under the department's proposal, but the income would have been delayed.

The department believes that it is not authorized to reduce the royalty obligation under AS 33.05.130(p), because of the limitation AS 33.05.130(j) appears to place on the commissioner's powers. If AS 33.05.130(j) applied only to leases that had not yet been unitized, AS 33.05.130(j) would be a nullity because, as a practical matter, unitization always precedes production. Related statutes should not be construed to make one statute a nullity.

Further, the general rule of statutory construction is that specific provisions control general provisions. Under this rule, the specific royalty reduction provisions of AS 33.05.130(j) would control the general provisions of AS 33.05.130(p).

Further, the legislative history of AS 33.05.130(j) argues against using AS 33.05.130(p) to circumvent the royalty reduction limitations stated in AS 33.05.130(j).

Testimony before the Legislature in 1978 focused on royalty reductions in conjunction with the increased flexibility given to the commissioner to select bidding methods. A prime concern was to prevent royalty bid manipulation, where a bidder obtains a tract by bidding an unreasonably high royalty counting on a subsequent royalty reduction to make the lease profitable. Although the companies obtained their leases at a fixed royalty sale, the policy against royalty bidding is arguably still applicable. The companies' leases were about to expire, causing the companies to agree to increase royalties in order to keep from losing the leases which were about to expire.

The bill that created AS 33.05.130(j) went through several committee substitutes. One committee, the House Resources Committee, voted to place an express limit on the commissioner's powers under AS 33.05.130(p) by adding the language: "however, the commissioner may not reduce the state's royalty within any unit except as provided in (j) of this section." A subsequent committee reviewing the bill, the Senate Resources Committee, deleted that language, but its sole motive was that the language was unnecessary since that committee had already decided to delete AS 33.05.130(j) altogether.

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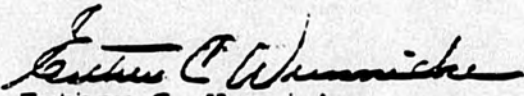
March 17, 1986

Later in the Senate Resources hearing, DNR pointed out that AS 33.05.130(j) granted the commissioner less power to reduce royalties than existed at that time under AS 33.05.140. The committee then voted to amend AS 33.05.140 to delete the commissioner's royalty reduction powers for oil and gas, and voted to reinstate AS 33.05.130(j). The committee immediately adjourned, without taking up the question of whether the previous committee's limitation of AS 33.05.130(p) should be retained.

In view of this legislative history, the department concluded that the specific royalty reduction limitations stated in AS 33.05.130(j) control the general royalty reduction powers granted in AS 33.05.130(p).

Thank you for the opportunity to comment on SS 33-130.

Sincerely,


Esther C. Wunnicks
Commissioner

Attachment:

cc: Senator Settya Fahrenkamp

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

POUCH 7034
ANCHORAGE, ALASKA 99510

October 9, 1984

H. D. Haley
Conoco, Inc.
2525 C Street, Suite 100
Anchorage, Alaska 99503

Re: Royalty reduction request
for Milne Point.

Dear Mr. Haley:

This letter responds to your October 4, 1983 letter in which Conoco, Inc. requested a royalty reduction for the following State of Alaska Leases: ADL 47432, ADL 47433, ADL 47434, ADL 47437, ADL 47438, ADL 47439, ADL 315846, and ADL 319717 ("the Conoco Leases"). Due to the legal, economic and geologic considerations stated below, the Division of Oil and Gas has determined that Conoco's request must be denied.

Although we can appreciate the difficulties Conoco anticipates in profitably developing Milne Point production, the division is statutorily prohibited from granting the requested royalty reduction. AS 38.05.180(j) precludes the division from granting a royalty reduction until there has been two years' initial production from the field. In Conoco's request, you relied on certain contractual provisions as support for the requested royalty reduction. However, the Department of Law has advised us that those contractual provisions were mooted by the 1979 unit agreement covering the Conoco leases, and that the statutory restriction is applicable. Under the pertinent geologic and economic considerations, Milne Point must be regarded as a separate field for royalty reduction purposes. Since there has not been two years' initial production from the Milne Point Field, the division is statutorily prohibited from granting Conoco a royalty reduction. A more detailed discussion of these conclusions follows.

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A. Legal Considerations

The division has considered the contractual and regulatory provisions stated in Conoco's royalty reduction request, and has determined that those contractual provisions were superseded by the September 28, 1979 "Unit Agreement for the Development and Operation of the Milne Point Unit." That unit agreement expressly provides that its terms modify Conoco's prior leases, and expressly precludes the state from granting royalty reductions for covered leases until two years' production occurs from the field in which the lease is located. In 1978 the Alaska legislature had amended the royalty reduction statute, AS 38.05.180(j), to require two years' initial production from the field before the commissioner of natural resources could even consider granting a royalty reduction request. The unit agreement requirement brought the Conoco leases into conformity with that amended statute. Neither the statute nor the unit agreement provisions need be belabored here since they are treated at length in the April 24, 1984 memorandum of advice from Assistant Attorney General Bonnie Thie to the division. (Attached as Exhibit A)

The threshold questions are whether the Milne Point leases are located in a discrete field, and if so, whether there has been two years' initial production from the field in which the Milne Point leases are located. Although the division has no statutory definition of "field" for royalty reduction purposes, the memorandum of advice states three possible geologic definitions of field: (1) a common source of supply, pool or reservoir; (2) multiple reservoirs vertically separated; or (3) multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The memorandum of advice further delineates the legislative policies to be considered in applying those geologic definitions: (1) the policy of reducing royalties when necessary to ensure that economic pressures would not cause an oil and gas field to be prematurely abandoned as production begins to decline, and (2) the countervailing policy of preventing speculative royalty bidding, in which a firm would make an unrealistically high bid to secure a lease while counting on a subsequent royalty reduction to make development of the lease profitable. The memorandum of advice concludes that the division must apply its expertise to those geologic, economic, and policy issues to determine both the scope of the Milne Point Field and whether two years' production has occurred from the Milne Point Field.

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B. Geologic Considerations

Conoco's counsel has suggested that for purposes of Conoco's royalty reduction request, the Milne Point leases be considered as part of the Kuparuk Field. However, under each of the three geologic definitions of field identified in the memorandum of advice as being most pertinent to royalty reductions, Conoco's Milne Point Unit constitutes a field separate from the Kuparuk Field. A technical review of the subsurface geology, regional stratigraphic data, and the reservoir characteristics of the productive formation in the Kuparuk and Milne Point Units confirms that the Milne Point leases will produce from an accumulation separate and distinct from that which is productive in the Kuparuk River Unit.

Petroleum occurs in several stratigraphic intervals in both the Milne Point Unit and the Kuparuk River Unit. However, petroleum production from the Kuparuk River Unit to date in commercial quantities has been limited to production from the Kuparuk Formation, as that formation was formalized by George J. Carman and Peter Hardwick, *Geology and Regional Setting of Kuparuk Oil Field, Alaska*, 1983 AAPG Bulletin, V. 67, p. 1014-31. With the exception of a pilot project in the stratigraphically higher West Sak Sands, none of the other stratigraphic intervals known to contain petroleum regionally, the Sadlerochit Formation, the Lisburne Formation and the Kekikuk Formation, have yet produced hydrocarbons in commercial quantities in either the Kuparuk or the Milne Point Unit areas. Since Conoco proposes to develop and produce only Kuparuk Formation reserves in the Milne Point Unit, only the stratigraphic setting and structural configuration of the Kuparuk Formation itself need be considered.

Carman and Hardwick informally subdivided the Kuparuk Formation's stratigraphic sequence into an upper and a lower member. They further divided the lower member into the "A" and "B" units, and the upper member into the "C" and "D" units (see attached Figure 1). The Kuparuk Formation is thought to have been deposited in a shallow marine environment, and its various stratigraphic units are generally laterally continuous. However, reservoir quality unit "C" is absent at Milne Point. Under Conoco's current proposal, the Milne Point Unit will produce only from the "A" and "B" units, while the Kuparuk River unit produces predominantly from the "A" and "C" units.

Three possible geologic definitions of "field" are most pertinent for royalty reduction purposes. "Field" may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs like those created in a

depositional environment such as a river delta. In reviewing whether Conoco's leases lie within the same field as the Kuparuk River Unit leases, the division considered each of these possible definitions. The second and third definitions may be briefly dismissed since they do not apply to the geographic and geologic parameters of the Kuparuk Formation in the Milne Point and Kuparuk River Unit areas. The Kuparuk River Unit and the Milne Point Unit could not be regarded as one field under the second definition, that of vertically separated reservoirs, because the two units do not share a common surface area. Although the units are both located over the Kuparuk Formation, they are geographically separated, with the Milne Point Unit located to the northeast of the Kuparuk River Unit. Nor could the two areas be described as comprising the same field under the third definition, that of multiple, partially overlapping individual reservoirs like those created in a depositional environment such as a river delta. The Kuparuk Formation consists of generally laterally-continuous units deposited in a shallow marine environment.

The "A" unit of the Kuparuk Formation is potentially productive in both the Kuparuk River and Milne Point Unit areas, making the first definition of field, a common source of supply, pool or reservoir, possibly applicable. However, to satisfy that definition, structural and stratigraphic continuity must exist between the Kuparuk River and Milne Point Unit accumulations. If either a structural barrier, due to folding or faulting, or a stratigraphic barrier, due to the absence of a continuous permeable bed, exists between the two accumulations, they can not be described as the same field.

Published data confirm the existence of a discrete Milne Point Field structurally distinct from the Kuparuk River Field. The Carman and Hardwick study describes a structural dip closure along the northern and eastern flanks of the Kuparuk Field. The lower half of attached Figure 2, taken from that study, demonstrates how a combination of folding and faulting have resulted in a separate Kuparuk Field hydrocarbon accumulation. The northeast border of the Kuparuk Field is delineated by an oil-water contact located southwest of the Milne Point Unit. The top half of Figure 2 shows the Social Simpson Lagoon 32-14 Well (dry hole) and the abandoned ARCO West Sak 25 Well, with the oil-water contact of the Kuparuk Field located to the southwest. Based on data from those wells, the Milne Point Field oil-water contact appears to lie to the northeast. The oil-water contact on the northeast side of the Kuparuk Field is also shown on the attached Figure 3, a structure contour map submitted by ARCO

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Alaska, Inc., operator of the Kuparuk River Unit. On this map, the oil-water contact is placed at approximately minus 6450 feet subsea, similar to the location shown in Figure 2.

Other public and confidential data on file with the division similarly demonstrate structural discontinuity between the Kuparuk and Milne Point accumulations. Separate oil-water contacts exist for each field, with the drainage pattern between the two fields being northeastward in the case of the southwestern edge of the Milne Point Field, and southwestward in the case of the northeastern edge of the Kuparuk Field. There exists an intervening structural discontinuity between the areas so extensive as to prevent a common source of supply, pool, or reservoir. Thus, the Kuparuk River and Milne Point Units contain two separate and distinct fields, even though the "A" unit is potentially productive in both areas.

Available geological data support the conclusion that the Milne Point Field and the Kuparuk Field contain separate accumulations of hydrocarbons. Under the relevant geologic considerations, the Conoco Milne Point Unit leases are not within the same field as the Kuparuk River Unit leases.

C. Economic Considerations.

The determination of whether Conoco's Milne Point Unit leases could at this time legally receive a royalty reduction must be made in light of legislative intent to prevent premature abandonment of producing fields and to preserve the integrity of royalty bidding. Specifically, the memorandum of advice instructs the division to consider "... whether the legislature's objectives will be met if there is no production history or cost data from an area linked by geology or economics to the applicant lease (e.g., shared cost, geologic and engineering data); whether reducing the royalty on oil or gas from one area produced independently of another area will prolong the production life of the other area; and whether, if there had been royalty bidding, reducing the royalty under the instant circumstances would make a sham of that bidding."

The legislative policy of preventing early abandonment of a producing field cannot be met if there is no demonstration by the applicant that the costs of continued production exceed a "reasonable" rate of return on the lessee's discounted investment. Conoco's costs to develop the Milne Point Unit leases cannot be determined directly from the costs ARCO incurred in developing the Kuparuk River Unit leases. Since the major

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production from each field occurs from different horizons within the same stratigraphic interval, the formation characteristics and the anticipated producing rates can be expected to vary. In recognition of this fact, the scale of development for each field is unique to that field. The Milne Point Field reserve size is much smaller than the Kuparuk Field reserve size. Accordingly, the investment required by Conoco to fabricate and install production facilities at Milne Point is but a fraction of the costs associated with developing the Kuparuk Field. Moreover, the rates of return which may be "profitable" to ARCO or its partners in the Kuparuk Field provide little, if any, indication of what may be profitable to Conoco and the other working interest owners in the Milne Point Field.

Whether Conoco can operate the Milne Point Field profitably can only be demonstrated retrospectively after Conoco installs production and transportation facilities and commences production at Milne Point. Conoco can speculate as to its future successes or failures, but the legislature clearly contemplated that the department would consider more than the lessee's prognostications (based on a third party's performance in dissimilar circumstances) in determining whether or not to grant a royalty reduction. Similarly, absent a history of production, there is no basis for making an argument that reducing the royalty rate of the Kuparuk leases would prolong the production life of the Milne Point leases, or vice versa.

The legislative policy against allowing royalty reductions in circumstances where the royalty reduction would make a sham of royalty bidding would also be contravened if the division granted Conoco's request. To grant the requested royalty reduction despite Conoco's lack of sufficient production and cost data would make a sham of royalty bidding, because, in essence, Conoco did "bid" the 20 percent royalty rates for those leases for which it is now requesting a reduction. The leases in question were nearing the expiration of their primary terms in 1979 when Conoco requested that they be combined to establish the Milne Point Unit, thus extending their primary term and enabling Conoco and its partners to pursue a delineation drilling program. Each of the original leases provided for a royalty rate of 12.5 percent. As one of the conditions of committing those leases which would not otherwise have been held by their own terms, former Commissioner of Natural Resources LeRasche increased the lease royalty obligations to 20 percent. Conoco and all the other potential working interest owners had the option at that time to refuse the royalty increase and to allow the leases to expire. ARCO, for example, chose not to join the unit as a consequence of this requirement. Conoco, however, agreed both to

the royalty increase and to other modifications of the original lease terms. Conoco then formed the Milne Point Unit and began an aggressive delineation and development program.

By agreeing to the increased royalties imposed as a condition to the lease term extensions, Conoco was allowed to retain what were then suspected to be extremely valuable leases without having to compete openly with other knowledgeable companies for that privilege. In 1979, two of the leases proposed for commitment to the Milne Point Unit contained wells certified by the department as capable of producing in paying quantities. Had Conoco allowed the Milne Point leases to expire, the department would have reoffered the leases, presumably under a royalty or net profit share bidding system or with a higher fixed royalty, and Conoco would have been forced to compete with other potential lessees to acquire the new leases. Conoco agreed to the increased royalty with full knowledge of the commerciality of the certified wells and with perhaps the best knowledge then available of the development requirements for the reservoirs. In light of these circumstances, it would seem both unfair to other potential lessees and irresponsible on behalf of the department to grant the requested royalty reduction without an unequivocal showing by Conoco that Milne Point development will not be economically feasible absent a royalty reduction. This showing can only be made when there are sufficient production and cost data for the department to evaluate.

D. Conclusion

Both the economic and the geologic considerations pertinent to the division's evaluation of Conoco's royalty reduction request show the existence of a Milne Point Field that is discrete from the Kuparuk Field for royalty reduction purposes. Conoco accepted the current 20 percent royalty in order to retain its Milne Point leases, and the profitability of Conoco's Milne Point development cannot be determined by reviewing Kuparuk Field development costs. To grant Conoco a royalty reduction request at this time would thus violate the legislative policy against speculative royalty bidding and would not advance the legislative policy of preventing premature abandonment of producing fields. The underlying geology also supports the division's determination that the Milne Point Field is discrete from the Kuparuk Field, showing two distinct accumulations within a larger geologic formation.

Since the Milne Point Field is separate from the Kuparuk Field, the Commissioner is statutorily prohibited from

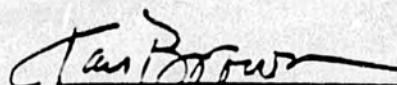
000540

AGO 1187128

H. D. Haley
Conoco, Inc.

October 9, 1984
Page 8

granting Conoco's royalty reduction request until after two years' initial production from the Milne Point Field itself. The division's decision is based on a consideration of the currently available economic and geologic data. If Conoco wishes to pursue its royalty reduction request further, it is, of course, entitled to apply formally for royalty reduction under 11 AAC 83.185. Upon Conoco's fulfillment of the requirements of subsection .185(a), the Commissioner will schedule a public hearing at which Conoco can present further information and evidence. If you have any questions concerning this letter, please feel free to contact me.


Ray Brown, Director
Division of Oil and Gas

Enclosures

000517

AGG 1187129

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

400 WILLOUGHBY AVE
JUNEAU, ALASKA 99801-1774
PHONE: (907) 465-2400

April 29, 1987

Mr. Tom Painter
Division Manager
Conoco, Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

Dear Mr. Painter:

As you requested in your April 20, 1987 letter, I am writing to inform you of my decision regarding whether the department has the statutory authority to grant Conoco a reduction in its royalty on production from the Milne Point Unit in November, 1987.

My staff and I have reviewed both the applicable statutes and the history of production at the Milne Point field carefully. In addition, we have conferred with Assistant Attorney General Steve Porter who has conducted a review of the legislative history, the statutes and the case law on our behalf. Based upon that review, I have concluded that I do not have the authority to approve a request to reduce royalty rates until after two years of production from the Milne Point Unit has occurred.

Although November, 1987 represents the two-year anniversary of the commencement of production from the Milne Point Unit, two years of initial production will not have occurred by that time. My reading of the statutes confirms that there must be two years of actual production to form the basis for the economic review which must precede and support any decision to reduce the royalty rate for a producing field. Thus, the two-year period of initial production for the Milne Point Unit is tolled during the period production is suspended, as is currently the case.

Staff from the Division of Oil and Gas concur with Conoco's economic assessment of the losses incurred by continued production at Milne Point, and agree that had those losses been experienced over a two-year production history, a royalty reduction would be advisable. On the basis of their

ANCHORAGE DIVISION	
MAY - 7 '87	
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SOC	
PJC	
ARM	X
TLH	
WHR	

Mr. Tom Painter

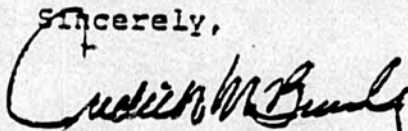
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April 29, 1987

analysis I remain sympathetic to Conoco's dilemma. However, the department's options are limited under the statutes, and a royalty reduction at this time is not possible.

If you have any additional questions or are interested in discussing other options which might be available, please feel free to call me.

Sincerely,



Judith M. Brady
Commissioner

ENCLOSURE 17

SUMMARY OF LEASE SALES THAT OFFERED EXPLORATION INCENTIVE CREDITS

SALE #	SALE AREA	TRACT #S	ADL NUMBERS	RATE PER FOOT DRILLED	% CAP ON COSTS	EIC TERM	EFFECTIVE DATE OF LEASES	# OF ACTIVE LEASES 1/23/95	# TRACTS OFFERED W/EICs	EICs GRANTED
36	BEAUFORT SEA	001-012	343101-343112	\$750	40%	10 YEARS	8/1/82	4	12	1
37	MIDDLE TANANA BASIN	005-154	345005-345154	\$250	30%	7 YEARS	11/1/82	0	150	1
34	PRUDHOE BAY UPLANDS	001-014	344003-344017	\$500	40%	10 YEARS	12/1/82	0	15	1
		015-261	344018-344245	\$375	30%	10 YEARS	12/1/82	0	228	2
39	BEAUFORT SEA	001-017	355001-355017	\$1,600	40%	10 YEARS	8/1/83	3	17	2
		018-041 & 047	355018-355041 & 355047	\$1,200	30%	10 YEARS	8/1/83	23	25	5
43A	COLVILLE RIVER DELTA	070-078	364470-364478	\$1,200	30%	10 YEARS	8/1/84	9	9	1
	PRUDHOE BAY UPLANDS	079-084	364479-364484	\$375	30%	10 YEARS	8/1/84	0	6	0
54	KUPARUK UPLANDS	001-089	372001-372108	\$300	15%	5 YEARS	4/1/88	47	108	2
70A	KUPARUK UPLANDS	001-135	375001-375135	\$300	20%	5 YEARS	4/1/91	101	135	5
								187	705	20

The State offered Exploration Incentive Credits in seven competitive lease sales from 1982 through 1991. EICs were offered on 705 tracts. Only 20 wells have been drilled earning EICs. The State has granted EICs totaling \$58,666,846.26.

Enclosure 17

EIC.XLS
1/26/95

ENCLOSURE 18

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 265 6101

James M. Davis
Senior Vice President

NOV 12 AM 11:15



RECEIVED

NOV 15 1993

November 9, 1993

DIVISION OF OIL & GAS

State of Alaska
Department of Natural Resources
Division of Oil and Gas
P.O. Box 7034
Anchorage, AK 99510-7034

HAND DELIVER

Attn: Mr. James E. Eason, Director

Gentlemen:

ARCO Alaska, Inc., on behalf of itself and Union Texas Petroleum Alaska Corporation, is hereby filing the attached Application For Exploration Incentive Credits for expenditures through October of 1993 in conjunction with drilling the Kuukpik Unit #3 on ADL-364477. This Application is made pursuant to 11 AAC 83.800 and the Notice of State of Alaska Competitive Oil and Gas Lease Sale 43A.

The Kuukpik Unit #3 well spudded on February 16, 1993 and was drilled to a measured depth of 6,880' feet. Total depth was reached on March 3, 1993 and the well was abandoned on April 14, 1993. Based upon the Exploration Incentive Credit guidelines contained in the Notice of Sale, the gross credit is \$2,794,016.15, being 30% of the total well costs to date of \$9,313,387.16.

The Notice of State of Alaska Competitive Oil and Gas Lease Sale 43A requires that the EIC must be earned and used within ten (10) years of the effective date of the lease. This will require that the EIC must be used prior to August 1, 1994. We will appreciate the State's consideration in this regard.

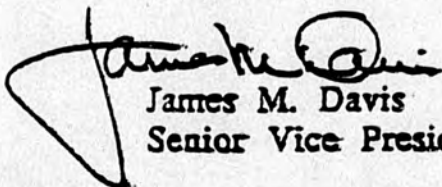
Enclosure 18

State of Alaska
Exploration Incentive Credits Application
November 9, 1993
Page 2

In accordance with 11 AAC 83.815, the attached Application for Exploration Incentive Credits is being submitted in triplicate. Please note that this is not a final accounting for Kuukpik Unit #3. Once a final accounting is available, we will file an additional application for any remaining credits. Should you have any questions or require additional information, please contact Brad Dowdell at 265-6115.

We appreciate your consideration in this matter.

Very truly yours,


James M. Davis
Senior Vice President

IT

Attachment

cc: Elizabeth Williams
Union Texas Petroleum Alaska Corporation
1330 Post Oak Road
Houston, TX 77056

ENCLOSURE 19

The original Kuukpik #3 EIC Decision and Finding contains information that is confidential under AS 38.05.035 and 11 AAC 82.810. The enclosed copy of the Decision and Findings contains only those sections of the document that do not incorporate or discuss confidential data. DNR Commissioner Noah found that the Kuukpik #3 well failed to qualify as an "exploration well" as defined by 11 AAC 02.020 and therefore was not eligible for an EIC.

WALTER J. HICKEL, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

P.O. BOX 107005
ANCHORAGE, ALASKA 99510-7005
PHONE: (907) 762-2483

CERTIFIED MAIL # P 377 614 920
Return Receipt Requested

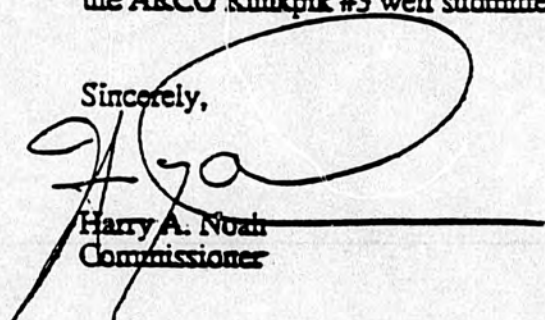
October 13, 1994

Mark R. Landr, District Landman
ARCO Alaska Inc.
P.O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Landr:

Enclosed is my decision regarding the application for an exploration incentive credit for the ARCO Kuukpik #3 well submitted by ARCO and Union Texas Petroleum.

Sincerely,



Harry A. Noah
Commissioner

Enclosure

7
Confidential

**ALL CONFIDENTIAL INFORMATION HAS BEEN DELETED
FROM THIS COPY OF THE DECISION AND FINDINGS**

**DECISION AND FINDINGS OF THE COMMISSIONER
ALASKA DEPARTMENT OF NATURAL RESOURCES ON THE APPLICATION
FOR EXPLORATION INCENTIVE CREDITS FOR THE ARCO KUUKPIK #3
WELL**

I. INTRODUCTION AND BACKGROUND

ARCO Alaska Inc. (ARCO), on behalf of itself and Union Texas Petroleum, applied for an exploration incentive credit (EIC) for the ARCO Kuukpik #3 well (Kuukpik #3). The application claimed total well costs of \$8,256,000.00 and requested a credit of \$2,794,016.15. The application is denied because the Kuukpik #3 fails to qualify as an "exploratory well" under the EIC regulations.

The Kuukpik #3 was drilled on ADL 364477. This lease was offered in Competitive Oil and Gas Lease Sale 43A which was held May 22, 1984. ADL 364477 was eligible for an EIC to be calculated at the rate of \$1200 per foot drilled for the first exploratory well per tract (lease). The credits, however, could not exceed 30 percent of the total exploratory well costs. The credits were to be earned and used within 10 years of the effective date of the lease. The Kuukpik #3 was spudded on February 16, 1993, drilled to a measured depth of 6880 feet and abandoned on April 14, 1993.

ARCO submitted the application on November 9, 1993. The Division of Oil and Gas (Division) requested additional technical data from ARCO. These data requests resulted in several meetings and numerous phone conversations between Division and ARCO staff and the transmittal of confidential well, seismic, engineering data and other information. Several times the Division specifically requested ARCO's pre-drill prospect maps. Nevertheless, ARCO did not provide them. The application was considered complete and following notification of ARCO, the record was closed on June 10, 1994.

On July 27, 1994 the commissioner supplied ARCO with a draft decision denying the EIC and allowing ARCO until August 15, 1994 to submit any comments or additional materials that they wished to be considered before a final decision was issued. Following their receipt of the draft decision ARCO requested and received a meeting with the Division to discuss the draft decision. At that July 28, 1994 meeting, Division staff explained the draft decision, discussed EIC regulations and restated the need for ARCO to supply a pre-drill prospect map (preferably a net pay isopach map). On August 15, 1994 ARCO requested a two-week extension of the August 15 deadline in order to gather additional data and comment on the draft decision. This request was granted by DNR. ARCO submitted their additional information to the Division on August 29, 1994. A discussion of their data and interpretations appears in Section III.

II. DISCUSSION OF THE EXPLORATION INCENTIVE CREDIT DECISION CRITERIA

Under AS 38.05.180(i), the commissioner of the Department of Natural Resources was authorized to establish an EIC system to encourage exploration of state leases through either geophysical work or the drilling of an exploratory well. An EIC is an optional provision in the state's lease form and is designed to encourage early exploration of its lands for hydrocarbon potential.

Under 11 AAC 83.800, the commissioner might or might not grant an EIC for costs incurred in either drilling an "exploratory well" or conducting "geophysical work". Under 11 AAC 83.820, "exploratory well" is defined as:

a well drilled for the purpose of oil and gas exploration that

(A) is located three miles or more from any other well drilled for oil and gas with all distances measured as the horizontal distance between exploration targets, or

(B) is within three miles from a well drilled for oil and gas, but tests potential hydrocarbon traps that the commissioner, after analyzing evidence submitted by the lessee and other information, determines constitute a distinctly separate exploration target.

To qualify as an "exploratory well" the commissioner, first must find that the well was drilled for the "purpose of oil and gas exploration". Second, he must find that either one of the two criterion has been established: (1) the distance criterion (A) above, or (2) the separateness criterion (B) above. For purposes of this discussion, it is assumed that the Kuukpik #3 was drilled for the purpose of oil and gas exploration.

(A) The distance criterion. The distance criterion provides an objective, measurable test to determine if a well qualifies as an exploratory well. To qualify for an EIC under this criterion, an oil and gas well must be drilled three miles or more from another oil and gas. The distance between wells is the horizontal distance between the well penetration of the target in the applicant's well and the well penetrations of the targets of surrounding wells. This is a critical aspect of the EIC regulations and the lessee should ensure that the well bore is three miles or more from other wells in order to qualify for the credit under the distance criterion.

(B) The separateness criterion. If a well does not meet the distance criterion, it may still be considered an "exploratory well" under the EIC regulations if the well meets the separateness criterion. Under the separateness criterion, the well must target "potential hydrocarbon traps" that the commissioner determines to be a "distinctly separate exploration target" from any other known oil and gas traps or accumulations. "Target" implies the primary geological trap or accumulation identified by the operator before drilling the well (See H. William & C. Meyers, Oil and Gas Terms 984 (7th ed. 1987)). The target must be "distinctly separate." This suggests that the targeted trap must be "set apart from ... [,] not connected [with, or] disjoined from any other trap (The American Heritage Dictionary of the English Language, 1181 (1970)). Moreover, the applicant bears the burden to show that this separateness is distinct.

III. APPLICATION OF THE DECISION CRITERIA

The Kuukpik #3 was drilled less than three miles from two previously drilled wells, the Amerada Hess Colville Delta 25-13-6 #1 (A-H 25-13-6) and the Gulf Colville Delta (Gulf C-D). Therefore, since the well does not meet the distance criterion, in order to qualify for an EIC the well must satisfy the separateness criterion.

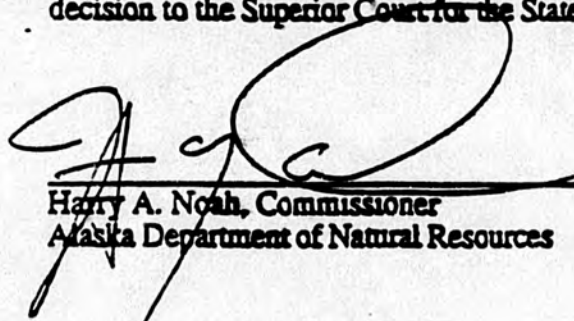
After examination of the data, ARCO's stated pre-drilling intent for drilling the well, and in light of the language and intent of 11 AAC 83.820, the Kuukpik #3 fails to qualify for an EIC. 11 AAC 83.820 requires that an "exploration well" which was drilled less than three

miles from another well, "tests potential hydrocarbon traps" that "constitute a distinctly separate exploration target". The word "potential" means "possible" as opposed to "actual" (Random House College Dictionary (1980)). This language insures that an EIC is awarded for drilling a specific, and "distinctly separate exploration target," that has been identified before drilling. EICs are not intended as reward for unexpected chance discoveries, delineation, or development wells. Additionally, use of the word "potential" allows DNR to grant an EIC regardless of what the well actually found, and thus, an EIC reward is not conditioned on a post-drilling analysis of the well results. This standard helps protect an applicant's right to an EIC if the well fails to discover a hydrocarbon trap.

IV. FINDINGS AND DECISION

The Kuukpik #3 was drilled less than three miles from the previously drilled A-H 25-13-6 and the Gulf C-D wells. Furthermore, the Kuukpik #3 failed to test potential hydrocarbon traps that constitute a distinctly separate exploration target from those found within the A-H 25-13-6 well. Therefore, the Kuukpik #3 fails to qualify as an "exploratory well" under 11 AAC 83.820 and does not qualify for an EIC. ARCO's application is denied.

Absent the filing of a request for reconsideration with the Commissioner in accordance with 11 AAC 02.020, this decision constitutes the final administrative agency decision and, pursuant to Rule 602(a)(2) of the Alaska Rules of Appellate Procedure, you have thirty days from the date this decision is mailed or otherwise distributed to you to appeal the decision to the Superior Court for the State of Alaska.



Harry A. Noah, Commissioner
Alaska Department of Natural Resources

10/14/94
Date

ENCLOSURE 20

EXPLORATION INCENTIVE CREDITS

Report Month: November 1994

ADL	WELL	COMPANY	CERTIFICATION DATE	TOTAL AMOUNT
343109	G-2 Well	Exxon	10/05/83	\$6,197,625.00
		Standard Alaska	12/27/83	4,152,408.75
		BPAE	10/05/83	2,045,216.25
344010	Leffingwell	ARCO	10/02/84	3,706,000.00
		Union	10/02/84	3,706,000.00
344033	J-1 Well	Exxon	10/31/84	5,119,500.00
355005	Long Island Well	Exxon	11/14/84	1,367,738.00
		Standard Alaska	11/14/84	1,378,076.00
345130	Tonek Hills	ARCO Alaska	08/02/85	715,530.81
355037	Colville Delta #1	Texaco	07/09/86	637,500.00
		Amerada Hess	07/08/86	888,594.00
		Diamond Shamrock (A)	07/08/86	100,128.00
		Mobil	02/05/87	432,511.00
		Placid Oil (C)	07/08/86	314,679.00
		Union Texas (B)	07/08/86	475,631.00
		Rosewood Resources	07/08/86	12,662.00
		Hunt Pet Co.	07/08/86	11,213.00
364478	Colville Delta Area AHC 25-13-6 #1 Well	Amerada Hess	10/12/87	677,853.00
		Union Texas (G)	10/12/87	508,390.00
		Texaco	10/12/87	225,951.00
		Maxus Expt. (G)	10/12/87	225,951.00
		Placid Oil	10/12/87	129,115.00
		Rosewood Res.	10/12/87	21,360.00
		Hunt Pet Co. (G)	10/12/87	18,987.00
355038	Colville Delta #2	Amerada Hess	10/28/87	757,731.46
		Union Texas (G)	10/28/87	205,106.95
		Texaco	10/28/87	273,475.93
		Maxus Expt. (F)	10/28/87	273,475.93
		Placid Oil (H)	10/28/87	423,982.26
		Rosewood Res. (D)	10/28/87	77,561.49
		Hut Pet Co. (G)	10/28/87	68,943.50
355039	Colville Delta #3	Amerada Hess	10/28/87	364,048.13
		Union Texas (G)	10/28/87	91,012.03
		Texaco	10/28/87	364,048.13
		Maxus Expt. (G)	10/28/87	364,048.13
		Placid Oil (H)	10/28/87	178,918.37
		Rosewood Res. (D)	10/28/87	34,416.31
		Hut Pet Co. (G)	10/28/87	30,592.28
344176	Gyr #1	ARCO Alaska, Inc.	11/15/90	719,560.56
		Conoco	11/15/90	761,481.20
		Amerada Hess	11/15/90	761,481.20
		ARCO Alaska, Inc.	2/4/92	16,151.00
		Amerada Hess	2/4/92	9,479.94
		Conoco	2/4/92	9,479.93
355021	NW Milne #1	Conoco	7/10/92	1,440,243.90
		Conoco	2/9/93	660,321.00
		Conoco	6/16/93	24,764.70
375044	Sequoia #1	Conoco	7/10/92	288,641.79
		Petrofina	7/10/92	352,784.41
		Conoco	2/9/93	16,333.56
		Petrofina	2/9/93	19,963.24
375076	Cirque #2	ARCO Alaska, Inc.	2/9/93	884,118.53
375108	Tara #1	ARCO Alaska, Inc.	2/9/93	740,305.91
355036	Kalubik #1	ARCO Alaska, Inc.	2/9/93	3,019,927.70
		Union Texas	2/9/93	262,602.41
372104	Fiord #1	Union Texas Petro AK	2/9/93	191,018.62
		ARCO Alaska, Inc.	2/9/93	1,719,167.60
372006	Tulaga #1	ARCO Alaska, Inc.	3/25/93	1,635,000.00

355011	Jones Island #1	ARCO Alaska Inc. Union Texas	7/12/93 7/12/93	2,160,000.00 2,160,000.00
375133	Cascade Well #1	BP Exploration	4/4/94	925,348.63
375061	Yukon Gold #1	BP Exploration	8/8/94	3,312,689.72
GRAND TOTAL				\$58,666,846.26

- (A) Assigned \$432,511 of EIC to Mobil Oil Corp. effective 02/05/87
- (B) Assigned entire EIC to BP Alaska effective 02/03/87
- (C) Assigned entire EIC to Texaco Inc. effective 03/31/87
- (D) Assigned entire EIC to Texaco Producing Inc. effective 01/01/88
- (E) Assigned \$79,193.59 of EIC to Texaco Producing Inc. effective 02/01/88
- (F) Assigned entire EIC to Texaco Producing Inc. effective 02/01/88
- (G) Assigned entire EIC to Texaco Producing Inc. effective 05/17/88
- (H) Assigned entire EIC to Standard Alaska effective 05/17/88

Source: Alaska Department of Natural Resources, Division of Oil and Gas

ENCLOSURE 21

Incentive Credit For Geophysical Work

- To date, no company has applied for credit for conducting a geophysical survey.
- 11 AAC 83.310. Credit for Geophysical Work.
 - Copies of geophysical data obtained during a credit period must be submitted to the commissioner within 90 days after completion of collection and processing of data.
 - Geophysical work must be performed during the two seasons before the scheduled sale date.
 - Geophysical information which accompanies an application for EICs will be made public 30 days after the lease sale date. (this is why companies haven't taken advantage of this incentive.)

ARTICLE 8. EXPLORATION INCENTIVE CREDIT

Section

- 800. Exploration incentive credits
- 805. Credit for exploratory wells
- 810. Credit for geophysical work

Section

- 815. Filing of statements
- 820. Definitions

11 AAC 83.800. EXPLORATION INCENTIVE CREDITS. (a) If the commissioner receives a request for exploration incentive credit, the commissioner will, in his discretion, allow credits for expenditures for both exploratory wells and geophysical work against:

- (1) oil and gas royalty payable in-value and rental payments payable to the state; or
- (2) taxes payable under AS 43.55.

(b) The period during which exploration incentive credits may be earned and used and the percent of the exploration expenditures that will be allowed for credits in a particular region will be established by the commissioner and will be announced no sooner than two years before the sale but in no event later than the date of the notice of sale. The period during which exploration incentive credits may be earned and used may be extended at the discretion of the commissioner. Exploration incentive credits may be assigned. A notice of assignment must be filed with the commissioner on forms prescribed by the department. (Eff. 11/9/79, Register 72; am 8/15/82, Register 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.805. CREDIT FOR EXPLORATORY WELLS. Credits may be earned only for one well per sale tract as that tract is defined on the day of a competitive oil and gas lease sale. Actual footage drilled in exploratory wells may earn exploration incentive credits at a rate established by the commissioner. In place of credit for actual footage drilled, expenditures for other operations related to the well will be considered for credit in the following manner:

(1) The cost of constructing and preparing the drilling location will be credited on a case-by-case basis at the discretion of the commissioner, who will determine the specific costs applicable to the exploratory well.

(2) Credits for other costs incurred by the lessee when drilling the exploratory well will also be considered on a case-by-case basis.

(3) At the request of the commissioner, the lessee shall submit all cost information necessary to determine the accuracy of the requested credits. If more than one company participates in drilling the exploratory well, then credit will be allowed in proportion to the participation in the drilling cost of the well. (Eff. 11/9/79, Register 72; am 3/30/84, Register 89)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.810. CREDIT FOR GEOPHYSICAL WORK. (a) Geophysical exploration costs may be credited at a rate approved by the commissioner in the following manner:

(1) If the applicant desires credit for geophysical work, copies of the geophysical data obtained during the credit time period must be submitted to the commissioner within 90 days after completion of collection and processing of data.

(2) The commissioner will inspect the information submitted to ensure that the geophysical work was conducted according to accepted standards of geophysical practice before granting credits.

(3) The applicant is responsible for submitting correct information, for advising the state of any erroneous data previously submitted, and for correcting all errors in the geophysical information.

(b) Credits may be considered for geophysical work performed during the two seasons before the scheduled sale date.

(c) Geophysical information which accompanies an application under 11 AAC 83.815 for geophysical exploration incentive credits, including information submitted under (a)(1) - (3) of this section, will be made public 30 days after the lease sale date. (Eff. 11/9/79, Register 72; am 3/18/83, Register 85)

Authority: AS 38.05.022
AS 38.05.180

11 AAC 83.815. FILING OF STATEMENTS. (a) Applications for determinations of total exploration incentive credits must be signed and notarized by the lessee or its authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and must include an accounting of expenditures and the date the expenditure was made.

(b) Applications for geophysical work credits must be signed and notarized by the person performing the work or his authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and contain copies of the required geophysical information.

(c) The commissioner will, in his discretion, request additional information if an application contains insufficient information to determine the accuracy of the request for credit.

(d) Once exploration incentive credit is granted by the commissioner, the commissioner will certify to the grantee the amount of the credit, the work for which the credit was given, the period during which it may be (or has been) earned, and the period during which it may be applied.

(e) Approved credits, when used, must be reported on the monthly royalty or tax payment statement or on the yearly rental payment statement against which they are being applied. (Eff. 11/9/79, Register 72)

Authority: AS 38.05.030
AS 38.05.180

11 AAC 83.820. DEFINITIONS. Unless the context clearly requires a different meaning, as used in 11 AAC 83.800 - 11 AAC 83.820

(1) "commissioner" means the commissioner of the Department of Natural Resources, State of Alaska;

(2) "exploratory well" means a well drilled for the purpose of oil and gas exploration that

(A) is located three miles or more from any other well drilled for oil and gas with all distances measured as the horizontal distance between exploration targets, or

(B) is within three miles from a well drilled for oil and gas, but tests potential hydrocarbon traps that the commissioner, after analyzing evidence submitted by the lessee and other information, determines constitute a distinctly separate exploration target;

(3) "geophysical exploration season" means one year;

(4) "geophysical information" means the raw field data and all information necessary to compute, process, and prepare the field data for geological interpretation; for seismic work, this data includes the standard processed sections that are stacked after filtering and correction for statics and normal moveout;

(5) "geophysical work" means all geophysical methods used in hydrocarbon exploration and for the determination of geologic hazards, including but not limited to seismic, gravity, magnetic and electromagnetic measurements;

(6) "tax" means payments due under AS 43.55 or its successor tax;

(7) "actual footage drilled" means the well's measured depth, and may include sidetracking or redrilling necessary to reach the originally proposed bottom-hole location. (Eff. 11/9/79, Register 72; am 3/30/84, Register 89)

Authority: AS 38.05.020.
AS 38.05.180

ENCLOSURE 22

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage Alaska 99510-0360
Telephone 907 265 6511

J. K. (Ken) Thompson
President

RECEIVED

OCT 25 1994



October 21, 1994

DIVISION OF OIL & GAS

CONFIDENTIAL

Confidential information removed from this copy by DNR

Mr. Harry Noah, Commissioner
State of Alaska
Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, Alaska 99801-1796

RE: Application for Exploration Incentive Credits
Fiord No. 3 and Alpine No. 1 (Proposed Exploratory Wells)
ADL-384214 & ADL-380075

Dear Commissioner Noah:

ARCO Alaska, Inc., on behalf of itself, Union Texas Petroleum Alaska Corporation and Anadarko Petroleum Corporation, does hereby make an Application for Exploration Incentive Credits for the proposed drilling of the Fiord No. 3 and Alpine No. 1 wells on ADL-384214 and ADL-380075, respectively, as further set forth on Attachment "1." This Application is made pursuant to AS 41.09.100, enacted by the Alaska Legislature earlier this year (1994 SLA Ch. 39; Senate Bill 151).

As you know, that legislation provides that the DNR commissioner "may extend to a qualified applicant an exploration incentive credit for each of the following activities performed on land in the state, regardless of whether the land is state-owned land: ... (3) drilling an exploratory well." AS 41.09.100(a), (emphasis added).

ARCO Alaska, Inc. believes that authorizing an exploration incentive credit ("EIC") for the Fiord No. 3 and Alpine No. 1 well(s) would be an excellent opportunity for the state to send a message of encouragement to the few companies remaining active in exploration of Alaska's lands. It would also be consistent with the

Mr. Harry Noah, Commission
October 21, 1994
Page 2

Governor and Legislators' stated goal of encouraging resource development.

We understand that DNR is hesitant to use the EIC process enacted by AS 41.09.100-190 for state-leased lands that could have been leased with EIC's under AS 38.05.180(i). We believe that interpretation would deprive the state of its most significant opportunity to provide meaningful encouragement of exploration, particularly for the North Slope.

We see nothing in AS 41.09.100-190 to indicate that the new EIC program cannot be used to promote exploration of any lands in the state, whether leased under AS 38.05.180 or not. Indeed, as noted above, AS 41.09.100(a) expressly applies to "land in the state, regardless of whether the land is state-owned land", and AS 41.09.100(e) specifies the maximum EIC for "activities performed on state-owned land."

The state owns most of the central North Slope acreage, and the state's historic practice is to lease its most prospective acreage first. Given the ongoing exodus of exploration companies from Alaska, an interpretation of AS 41.09.100 that limits its EIC's to lands not leased under AS 38.05.180 would most likely turn the program into one that is rarely used on the North Slope.

The new EIC program appears to present the state with an opportunity to encourage exploration where it may have failed to do so before. The low interest by bidders at the last sale (Sale 75A) indicates that it would now be appropriate for the state to provide additional encouragement of Colville exploration activities.

The Colville High is a geologically complex area, in which exploration is expensive, with decidedly mixed results to date. The EIC program of AS 41.09.100 could be used to provide strong incentive to continue to explore this area, which is one of the last opportunities on state acreage to discover reserves producible through TAPS.

Mr. Harry Noah, Commission
October 21, 1994
Page 3

Under the statute, the Application must be approved prior to drilling (AS 41.09.100(c)(1)), may not exceed 50% of eligible costs relating to activities on state-owned land (AS 41.09.100(e)), and may not exceed \$5,000,000.00 per eligible project (AS 41.09.100(f)). AAI hereby requests approval on or before December 1, 1994 from the Department of Natural Resources for a EIC of 50% of the actual costs to drill and potentially evaluate the Fiord No. 3 and Alpine No. 1 well(s).

Should you have any questions or require additional information, please call Mark Landt at 265-1579. We appreciate your consideration in this matter.

Sincerely,



J. K. Thompson

ENCLOSURE 23

Position Paper
Department of Natural Resources
Exploration Incentive Credit Legislation
HB 200 & SB 151

The Exploration Incentive Credit Bill extends a program that already exists on State lands to all lands in the State. It provides a means for the State to obtain exploration data to which it would not normally be entitled. It may also encourage exploration on lands that will enhance the exploration of adjacent or nearby State lands.

Exploration Incentive Credits (EICs) are currently offered by the State as a means to encourage exploration on State lands. Under AS 38.05.180(i), the Commissioner of Natural Resources may authorize the use of incentive credits to encourage exploration of state leases through either geophysical work or the drilling of a well. Geophysical EICs can be earned if the work is performed during the two seasons immediately preceding an announced lease sale on land included within the sale area, and if the geophysical work is made public following the sale. Drilling EICs are based on the footage drilled and the region in which the well is situated. The decision whether or not to offer credits is sale specific and is determined by evaluating the perceived geologic potential of the sale area as well as the perceived cost of exploration.

Under the current program, credits may not exceed 50 percent of the cost of drilling or geophysical work. Credits may be used during a limited period established by the commissioner and may be assigned during that period. Credits may be applied against oil and gas royalties and lease rentals or taxes payable under AS 43.55. A credit must not exceed 50 percent of the payment toward which it is being applied. Amounts due the Alaska Permanent Fund must be calculated before the application of credits.

Governor Hickel's proposal in HB 200 and SB 151 is to expand the current EIC program to all areas of the state, with certain modifications and restrictions. This new legislation provides an amount of \$50 million that may be used over a period of ten years, with each individual project capped at \$5 million. Credits of up to 50 percent on state-owned land and 25 percent on non state-owned land will be allowed. In contrast, the current EIC program has no time limit and no cap. The new legislation also provides for credits to be applied against income and other taxes in addition to the severance tax. The credits remain transferable under the provisions of this bill and, as with the current plan, amounts due the Permanent Fund must be calculated prior to application of any credits.

All data acquired under the EICs must be submitted to the commissioner. Well data will be held confidential for 24 months after submission, but no extension of this period of confidentiality will be allowed (i.e. all well data will become public 24 months after submission unless the company gives permission to release it sooner). Geophysical data will be allowed to be shown, but not transferred to, any interested party.

The Governor recognizes that activities on lands adjacent to, or nearby, State lands may significantly affect State land. This new legislation allows the commissioner discretion to provide credits to obtain data that the State otherwise would not be able to get. The State, by statute, can now get all seismic data gathered on State land only—but has no mechanism to obtain data on non-state owned land. The data obtained as a result of this legislation will enhance our knowledge of State lands, and the geophysical data may be used as a marketing tool to attract investors to State land.

Bill aids search for oil

House OKs measure to pay for expenses

By IAN MADER
The Associated Press

JUNEAU — The state could pay much of a company's costs of oil exploration on unleased land in return for the resulting geological information, under a bill the House passed Wednesday.

The bill is one of two Hickel administration measures designed to get the state's oil reserves explored faster. It aims to collect information that could help promote drilling in, unexplored basins, especially in the Interior.

The proposed credit program could pay up to 50 percent of exploration costs on unleased state land, and 25 percent of costs on other land. The state could spend up to \$30 million during the 10-year program. No project could get more than \$5 million.

The natural resources commissioner would decide how much credit to award in each case, depending on how much the state stood to gain. Exploration on private land could shed light on prospects for nearby state land, state officials say.

"We could offer a number of dollars per foot for the well drilled," said Ken Boyd, deputy director of the Division of Oil and Gas. "If it's too far from state land, we would say, 'No, we're

OIL: House OKs money to help hunt

Continued from Page B-5

really not interested."

The bill was introduced by Gov. Wally Hickel and passed the Senate last year. It passed the House 37-2, and was to be returned to the Senate for agreement with changes.

The legislation originally would have authorized \$50 million for the program. The House also added a provision to disqualify companies that are in debt to the state.

Boyd said several Native regional corporations, including Doyon Ltd. and Cook Inlet Region Inc., were interested in using the credits to explore land they own in Interior Alaska. Companies that specialize in speculative geophysical work and sell their data to oil companies also would use the incentives, Boyd said.

Information gathered under the program could generate interest in the state's oil lease offerings, Boyd said.

State law already allows credits for up to 50 percent of exploration on leased lands in return for speedy exploration. Credits above 30 percent never have been awarded, Boyd said.

Rep. John Davies, D-Fairbanks, said some of the credits probably would be higher than needed to encourage exploration.

"I think the state is making a lot of concessions to the industry as it is," Davies said. "We just gave them another major exploration incentive bill. I think that should be enough for this year."

Please see Page B-6, OIL

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

P.O. Box 107005

Anchorage, AK 99510-7005

PHONE: (907) 782-2483

FAX: (907) 562-4871

400 WILLOUGHBY AVENUE

JUNEAU, ALASKA 99801-1798

PHONE: (907) 465-2400

FAX: (907) 465-3888

November 18, 1994

J. K. Thompson, President
ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Thompson:

I am responding to your letter of October 21, 1994, in which you requested my pre-approval of Exploration Incentive Credits under AS 41.09.100 for the drilling of proposed wells Fiord No. 3 and Alpine No. 1. For the reasons set forth below, I must deny your request.

AS 41.09.100 was not intended to apply to the drilling of wells on state leased lands. The language of the bill itself notes that AS 41.09.100 is "...an incentive program distinct from the exploration incentive credit authorized by AS 38.05.180(i)..." (emphasis added). AS 38.05.180(i) allows the commissioner the discretion to use incentive credits on leased lands by announcing their availability prior to the lease sale, not afterwards. It allows the commissioner the option of using EICs to encourage exploration and development in those areas in which he deems the assistance to be in the state's interest.

In making EICs available to all competitive bidders before a lease sale under the provisions of AS 38.05.180(i), the commissioner maintains a level playing field. All bidders are aware of the availability of the EICs and of the terms under which they may be earned, thus enabling everyone to make an informed decision regarding their competitive bid. Making EICs available selectively to some lessees and not to others who had bid competitively under the same terms would raise serious issues of fairness.

AS 41.09.100, on the other hand, was always intended to apply only to those areas within the state where the Department of Natural Resources would not otherwise receive data from the drilling of wells or the gathering of geological or geophysical data. In other words, AS 41.09.100 was designed to encourage exploration of adjacent private and federal lands where the state is not entitled to receive data, as well as on certain unleased state land. The legislative record on this point is quite lengthy. Ken Boyd, Deputy Director of the Division of Oil and Gas, testified before the House Finance Committee on April 24, 1994, that "...it (CS SB151) would provide a means for the State to obtain exploration data to which it would

Enclosure 23

not normally be entitled..." Representative Joe Green, testifying before the House Judiciary Committee on March 25, 1994, stated that "...this bill (CS SB151) applies to unleased State land and private land..."

I have enclosed copies of the department's then contemporaneous Position Papers for HB 200 and SB 151, copies of two then contemporaneous articles from the Anchorage Daily News noting the restriction to unleased state lands, and finally, a copy of a table prepared by the department and distributed to legislators at hearings on the bills. The table differentiates the provisions of AS 38.05.180(i) and CSSB 151, explicitly noting the applicability of CSSB 151 to "unleased state land and private land".

While numerous EIC-eligible leases have been issued in the vicinity of the Colville Delta, the department's pre-sale analysis for both Sales 75 and 75-A suggested that EICs were not appropriate for those sales. I believe that the pace of subsequent exploration in that area confirms the willingness of lessees, including ARCO and its partners, to explore the area without additional financial support of the state.

You note in your letter that there was low interest by bidders at Sale 75-A and, therefore, it would be appropriate to provide additional encouragement of Colville exploration activities. In reviewing the records I find that Sale 75-A results indicate high, not low interest in that area. Sale 75-A records indicate that all eleven tracts offered in that sale were leased, either by Atlantic Richfield, a partnership of Atlantic Richfield and B.P., or by Union Texas Petroleum Alaska Corp.

Less than ten months before Sale 75-A was held, the department held Sale 75. That sale, which offered acreage surrounding the Sale 75-A acreage, also attracted strong bidder interest. Seven bidders exposed more than \$13.0 million in high bonus bids on 55 of the 90 tracts offered in that sale. I do not believe the results of either of these sales indicate "low interest."

Finally, Section 2 of AS 41.02.100 states that "the commissioner shall proceed to adopt regulations necessary to implement this act." While the Division of Oil and Gas and the Department of Law are proceeding with the writing of regulations, they are not yet complete. An early draft is currently under review by the Department of Law. The draft regulations will then be sent out for public review and comment. It is likely that one, or more, public hearings will be held. The regulations must then be submitted to the Lieutenant Governor for approval. This process cannot be completed by December 1st.

J. K. Thompson

-3-

November 18, 1994

In closing, it is my opinion that this administration has been committed to encouraging exploration and development, and it remains so.

Sincerely,



Harry A. Noah
Commissioner

Enclosures: as stated

Ken Boyd

Comparison of Existing and Proposed Exploration Incentive Credit Programs

EXISTING PROGRAM **AS 38.05.180(1)**

PROPOSED PROGRAM **CSSB 151**

Applies to

Specific Leased Land at the
discretion of the commissioner

Unleased State Land
& Private Land

Dollar Limitation

No Cap

\$30M Total/\$5M per Project

Sunset

No Time Limit

Sunsets in 10 years

Confidentiality

Extended Confidentiality for
wells may be allowed

No Extension
2 years max

Credit Allowance

Max of 50% of eligible costs

Max of 50% on State Land/
25% on Private Land

Credit Applies To

Severance Taxes only

All Taxes

No liquidated debt

Senate OKs remote-oil subsidy

By IAN MADER
The Associated Press

JUNEAU — The Senate has passed a bill that would allow the state to promote oil exploration on unleased lands by subsidizing up to 50 percent of a company's exploration costs.

The credits could be used to make it more attractive to explore in remote, untapped areas, particularly basins in interior Alaska, state officials say.

The amount paid by the state would be decided by the natural resources commissioner on a case-by-case basis, with no single project getting more than \$5 million. The state now offers such credits on leased lands in

exchange for speedy exploration.

Some environmentalists say the state should not be subsidizing any oil company activity. They also say they fear oil development in the Interior could cause major environmental problems.

Senate Bill 151, requested by Gov. Wally Hickel, passed 14-6 without debate Thursday, and was to be sent to the House pending a possible reconsideration vote.

The state would receive information from all such exploration projects, regardless of whether they are on state land. The state now is entitled to see

such data only for test drilling and seismological work on state land.

Ken Boyd, deputy director of the state Division of Oil and Gas, said the credits could be awarded based on how much the state stood to gain from the information, which could shed light on the prospects of nearby land.

The state would be able to offer up to 50 percent of the cost of exploration on state-owned land, and up to 25 percent on other land.

David van den Berg of the Northern Alaska Environmental Center in Fairbanks said he is

wary of any subsidy for oil companies.

"This establishes a potentially ugly precedent," he said. "Our basic reaction to incentives is: Give incentives to other companies, too. Ranching cockroaches could probably be viable with such incentives."

Environmentalists are less worried about the effects of the exploration than the effects of a discovery, van den Berg said.

"I think they would be conscientious about leaving a small footprint. But to us, it just means if you find stuff out in Minchumina, where's the nearest pipeline? What's going to happen then?"

THE ASSOCIATED PRESS

ENCLOSURE 24

COOK INLET DISCOVERY ROYALTY APPLICATIONS

<u>Name of Well</u>	<u>Lessee (present names)</u>	<u>ADL Number</u>	<u>Date of Discovery</u>	<u>First Affidavit or claim of discovery</u>	<u>Date of written decision granting discovery royalty</u>	<u>Effective date of the 10-year discovery royalty</u>	<u>Commencement of commercial production</u>	<u>Date 12 1/2% royalty replaced 5% discovery royalty rate</u>	<u>Period royalty actually reduced</u>
Falls Creek Unit No. 1	Chevron ARCO	00590	4/10/61	12/3/63	2/18/64	5/1/61	None	No royalty ever paid	Never used
Middle Ground Shoal No. 1	AMOCO Getty Phillips	17595	6/10/62	11/12/62	1/15/63	6/10/62	5/66	6/10/72	6 years 1 month
Cook Inlet State No. 1	Phillips	17589	8/21/62	11/12/62	11/24/64	9/1/62	3/69	9/72	3 years 6 months
Beluga River Unit No. 1	Chevron ARCO Shell	17599	12/1/62	9/17/63	12/19/62	1/1/63	3/68	1/73	4 years 10 months
Granite Point No. 1	Mobil Union	18761	5/16/65	5/21/65	9/14/65	6/1/65	5/67	6/75	8 years 1 month
Trading Bay No. 1-A	Union Marathon	18731	5/23/65	6/18/65	8/27/65	6/1/65	1/67	6/75	8 years 5 months
Trayling No. 1-A	Union Marathon	17594	9/29/65	10/28/65	1/19/82	10/1/65	10/67	10/75	8 years 1 month
Nichols Creek State No. 1	Teneco Superior	17598	4/28/66	5/23/66	8/19/66	5/1/66	10/68	No production after 1972	About 4 years

APPLICATIONS DENIED

<u>Name of Well</u>	<u>ADL Number</u>
Trading Bay No. 1 and No. 2	17597
Shoal Middle Ground Shoal	18754
W. Foreland Unit No. 3	18777
Redoubt Shoal No. 2	29690
Trading Bay State No. 1	35431

ENCLOSURE 25

**NORTH SLOPE
DISCOVERY ROYALTY APPLICATIONS**

<u>Lease ADL</u>	<u>Well Name</u>	<u>Field Name</u>	<u>Applicant</u>	<u>Date of Application</u>	<u>Status of Application</u>
28303	Prudhoe Bay State #1	Prudhoe Bay	ARCO	3/12/68	Granted
25633	Ugnu #1	Kuparuk	ARCO-BP	4/7/69	Granted
34633	Sag Delta #4	Endicott	BP	2/14/78	Granted
34635	Niakuk #5	Niakuk	BP	4/7/85	Granted
28297	Pt. McIntyre #3	Pt. McIntyre	ARCO	5/12/89	Granted
25906	Milne Point G-1	Milne Point	Conoco	12/7/89	Denied

Note:

Between 1968 and 1977 nine additional notice of discovery applications were filed, but the applicants never completed the full application procedure. Those nine applications are now expired.

ENCLOSURE 26



Tom Painter
Division Manager

Conoco Inc.
3201 C Street
Suite 200
Anchorage, AK 99503

September 7, 1989

Mr. James Eason
Director, Division of Oil and Gas
Department of Natural Resources
P. O. Box 7034
Anchorage, AK 99510-7034

RECEIVED
SEP 08 1989
DIV. OF OIL & GAS
DIRECTOR'S OFFICE

Dear Mr. Eason:

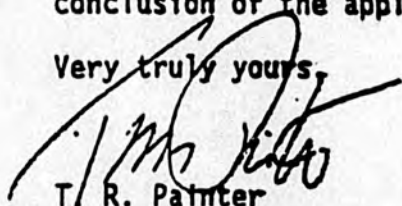
Pursuant to paragraph 12 of Lease ADL 25906 and 11 AAC 83.210(a), Conoco Inc. is submitting the attached Statement of First Discovery of Oil and Gas in Commercial Quantities in a Geologic Structure precedent to filing an application for discovery royalty for ADL 25906.

As indicated in the attached Statement and Exhibits, oil and gas has been encountered in sufficient showing in well no. G-1 to cause Conoco, a reasonable and prudent operator, to conduct further operations to complete said well in the discovery zone so that the well can be tested for potential oil or gas production in commercial quantities.

As required in 11 AAC 83.210(b), Conoco will undertake production tests in well no G-1 to establish that oil and gas has been discovered in commercial quantities. This testing will take place in the latter half of September, 1989, and we will furnish you sufficient notice and transportation (if requested) for a representative of your department to witness the testing. The geologic data required in 11 AAC 83.210(c) will be furnished in a timely manner.

If you need additional information concerning this Statement, please contact Al Hastings at 564-7650. Conoco respectfully requests that the information contained in the Statement and attached Exhibits remain confidential until the conclusion of the application and certification process.

Very truly yours,


T. R. Painter
Division Manager

AEH(jr)
File 500.58.08

Enclosure 26



Conoco Inc.
Suite 200
3201 C Street
Anchorage, AK 99503
(907) 564-7600

December 7, 1989

RECEIVED

DEC 11 1989

DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

Mr. James Eason
Director, Division of Oil and Gas
Department of Natural Resources
P. O. Box 7034
Anchorage, Alaska 99510-7034

Dear Mr. Eason:

Pursuant to 11 AAC 83.215, Conoco Inc., as Operator of the Milne Point Unit and the sole Working Interest Owner of ADL 25906, requests discovery well certification for Well No. G-I. Conoco is in compliance with the filing provisions of 11 AAC 83.210.

It is my understanding that the Division of Oil and Gas will publish the appropriate notice of this application for discovery royalty. If you need additional information concerning this discovery royalty application, please contact me at 564-7601.

Attached to this application is a brief discussion of the Pre-Drilling Expectation and the Post-Drilling Verification for Well No. G-I. This discussion summarizes the other criteria that have been used in the more recent discovery royalty decisions.

Very truly yours,


David L. Bowler
Division Manager

AEH(jr)
Attachment
File 500.58.08

ENCLOSURE 27

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

PO BOX 7034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

April 4, 1991

DECISION

Conoco, Inc.	:	Oil and Gas Lease
Suite 200	:	ADL 28297
1201 C Street	:	Milne Point Unit
Anchorage, Alaska 99503	:	

MILNE POINT UNIT G-1 WELL DENIED CERTIFICATION
AS A DISCOVERY WELL

The Division of Oil and Gas (division) hereby denies certification of the Milne Point Unit G-1 well (G-1) as a discovery well. As discussed in greater detail below, this denial is based on the determination that overwhelming evidence, including that submitted by Conoco, Inc. (Conoco), clearly establishes that the G-1 well fails the essential "first discovery" requirement. The Shallow Oil Sands (SOS) and the larger structure of which it is a part was clearly discovered by previous exploration, and was publicly known.

Previous discovery is evidenced by: (1) several hundred earlier exploratory, Kuparuk River Unit and Milne Point Unit well penetrations which yield substantial electric log and/or core data to recognize the accumulation, and (2) previous successful flow tests of the accumulation from at least five other wells in the Milne Point Unit, and a pilot project within the Kuparuk River Unit. The division's evaluation is supported by the geological, geophysical, and engineering information submitted by Conoco, as well as by in-house data.

THE HISTORICAL BACKGROUND

The legal basis for the discovery royalty

The statute that authorized the granting of a reduced royalty rate for a discovery of a separate geologic structure was the former AS 38.05.180(a), which stated in part:

the holder of a lease who drills and makes the first discovery of oil or gas in commercial quantities in a geologic structure shall pay a royalty on all production under the lease of five percent for ten years following the date of discovery and thereafter the royalty rate of twelve and one half percent.

Although this provision was subsequently repealed, it was in effect when ADL 25906 was issued. Paragraph 12 of the lease describes the discovery royalty provision as follows:

If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five percent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five percent royalty rate shall not apply to all, but only, the production allocated to this lease under such agreement.

Regulations implementing the discovery royalty statute were initially adopted in August 1963 and were published at 11 AAC 505.74 - 11 AAC 505.748. They were subsequently amended and renumbered as 11 AAC 83.200 - 11 AAC 83.230. In January 1980, these regulations were repealed. In adjudicating the Conoco request for discovery royalty, the department has used the repealed regulations as a reference only, and does not consider them to be controlling.

Lease History

Humble Oil and Refining Company and Richfield Oil Corporation, in a 50-50 partnership, purchased Oil and Gas Lease ADL 25906 on December 9, 1964 at Competitive Oil and Gas Lease Sale 13.

The lease was issued as a conditional lease effective March 1, 1965, with a ten-year primary term and a fixed royalty rate of twelve and one half percent. Humble later became Exxon Corporation (Exxon), and Richfield became ARCO Alaska Inc. (ARCO). ADL 25906 was added to the Milne Point Unit during the second expansion of the Unit, effective June 1, 1983. Conoco acquired Exxon's interest in the lease on July 28, 1987 and ARCO's interest on November 2, 1988. Conoco currently retains 100 percent working interest and ownership in ADL 25906.

Drilling History

Four wells have been drilled on ADL 25906. The first well drilled on the lease was the Milne Point Unit G-1, which was spudded on August 10, 1989 and completed on August 22, 1989. The well was drilled to a measured depth of 4745 feet. The operator logged, cored, and tested the Shallow Oil Sands (SOS), which were, as anticipated, productive. Subsequently, three additional development wells have been drilled on G pad and four well each on H, I, and J pads.

Discovery Royalty Application History

Conoco submitted a Statement of First Discovery on September 7, 1989. The statement claimed to have discovered oil in "Upper Cretaceous Formation sandstones" in the Milne Point Unit G-1 well, located on ADL 25906, on August 15, 1989. On December 7, 1989 Conoco tendered an application for discovery well certification for the G-1 well based upon well tests conducted on October 31, 1989. In the discussion attached to and made part of the application, Conoco characterized the claimed discovery in terms of the "Shallow Oil Sands." On December 14, 1989 Conoco submitted "geologic data to establish the geologic structure from which the G-1 well produced oil in commercial quantities." That document also directed itself to the Shallow Oil Sands, and expressly equated intervals within the sands with what ARCO Alaska, Inc. calls the "West Sak" and the "upper Ugnu."

Division staff met with Conoco representatives on January 24 and February 6, 1990 to discuss the application. On November 1990, Conoco submitted additional geological and geophysical data in support of its claim. On December 10, 1990, after division technical staff determined that the application was complete, the division published notice and separately mailed notice of the discovery royalty application to known potentially interested parties.

The division received no responses during the thirty day comment period. Therefore, the application stands unopposed

by any third party. No one has requested a public hearing, and the division has not requested a hearing in light of the vast amount of available data and the fact that the applicant has had a full opportunity to make both formal and informal presentations of its technical and legal positions.

DISCUSSION

The G-1 well did not make a first discovery.

The fatal deficiency of the application, demonstrated unequivocally by materials submitted by Conoco itself, is the absence of any "first discovery." The location and distribution of the SOS have been known for almost two decades. Published maps of the geologic structure and the oil accumulation for the SOS existed prior to the drilling of the Milne Point G-1 well. The application itself makes clear that the operator of the G-1 well had a pre-drilling expectation that the well would in fact penetrate a productive pool within the same geologic structure and interval as had been penetrated by hundreds of other wells within the Milne Point and Kuparuk River Units. In light of the amount of available information prior to drilling, it is clear that the G-1 well can best be described as Conoco's first planned production well within the SOS. Below are listed a few of the facts demonstrating that the structure containing the SOS was discovered long before the G-1 well.

O The East Ugnu No. 1 Well

In 1969, twenty years before the G-1 well was drilled, the East Ugnu No. 1 well discovered¹ two structures containing hydrocarbons: the deeper Kuparuk Formation (which forms the basis of production from both the Kuparuk River Unit and the initial participating area of the Milne Point Unit), and a shallower structure (which contains the intervals Conoco refers to as the SOS). The shallower structure was tested and flowed heavy oil at a rate of 20 barrels per day.

The East Ugnu No. 1 well is located four and three-fourths miles to the southwest of the G-1 well. The geologic isopach and structure maps, cross sections and interpreted seismic data supplied by Conoco show that the SOS, present in both the

¹ Based upon this discovery by the East Ugnu No. 1 Well, the owners of ADL 25633 were granted discovery royalty rights for any production of oil and gas and associated hydrocarbons attributed to that lease from any zone of production, including the shallow sands, during the first ten years after the date of discovery, i.e., for the period from May 1, 1969 through April 30, 1979.

G-1 and East Ugnu wells, are contained within the same geologic structure. Furthermore, the sands present within the Shallow Sands Interval in both the G-1 and East Ugnu No. 1 well are part of the same reservoir. These sands are part of a large Late Cretaceous and Paleogene deltaic system, and are interpreted as being deposited in shelf, delta front, delta plain and fluvial environments.

Reservoirs found in these environments typically contain multiple stacked and partially isolated sands. The individual sand bodies which make up the SOS clearly demonstrate this reservoir heterogeneity. However, geological, geophysical, and engineering data indicate that, disregarding localized reservoir discontinuities and small faults, the SOS reservoir is continuous between East Ugnu No. 1 and Milne Point G-1.

○ Conoco's discovery royalty certification application

On December 7, 1989, Conoco filed its application for discovery royalty certification. Attached to and made part of that application was a discussion of pre-drilling expectations for the G-1 well. That document admits

The risk of geologic nonsuccess for the shallow sands at Milne Point is small. Sufficient regional data in existence before the drilling of Well No. G-1 minimized the risk of not finding the geologic structure.

The next paragraph of the document generally discusses the SOS in the Milne Point Unit and the West Sak in the Kuparuk River Unit as the same structure, and estimates that in excess of \$150 million had been expended in drilling, testing and pilot project work. The document bluntly characterizes the difficulty with establishing sustained production from the SOS prior to the G-1 well as a "completion and production problem, and not a question of finding sufficient in-place hydrocarbons."

The attachment to the application goes on to state that pre-drilling expectations were confirmed:

The post drilling confirmed that the basic geologic structural definition before drilling commenced was correct. Minor changes in sand thickness and fluid content slightly altered oil in place values.

This proves beyond any doubt that Conoco did not discover the structure. It knew to a high degree of confidence and specificity what it would encounter.

O The application for a participating area for production from the SOS

On November 16, 1989, Conoco applied to the Division of Oil and Gas for establishment of a participating area within the Milne Point Unit for purposes of production of hydrocarbons from the SOS. That application states that "The Shallow Oil Sands have been tested by six wells within the Milne Point Unit." The G-1 well was drilled in 1989. Of the other five, one, the A-1 well, was drilled in 1980, and the four others were drilled in 1982.

Nothing suggests that the SOS tested in the Milne Point G-1 well contains oil or reservoir rock of significantly better quality or quantity than revealed in the five previously tested wells within the Milne Point Unit. Thus, even without any consideration of the many wells drilled into and testing the SOS in the Kuparuk River Unit, Conoco's own submissions reveal the fact that five prior wells within the Milne Point Unit drilled into and tested the SOS many years prior to Conoco's claimed "first discovery."

O Geologic analysis submitted on December 14, 1989 and in November 1990.

That the SOS was discovered well before the G-1 well is further proven by Conoco's geologic interpretations submitted on December 14, 1989 and in November 1990. The December 14, 1989 document, entitled "Geologic Evidence in Support of the Discovery Royalty for the Shallow Oil Sands" states:

The Shallow Oil Sands (SOS) of Milne Point comprise 17 individual beds that are readily traced between 78 wells in and around the Milne Point Unit. The type log for the SOS at Milne Point is Conoco's A-1 well. ... Although these sands were originally found in 1969 by the SOCAL Kavearak 32-25 well, the nearby A-1 well was chosen as the type well because of its modern (1981) [sic] well log suite.

Emphasis added. This statement admits that the SOS was originally discovered in 1969, and that 78 wells predating the G-1 had explored it to the extent that it could be "readily traced." Indeed, Figure 3 to the document, entitled "SOS Regional Structure," includes a large area of the Kuparuk River Unit within its mapping of the SOS, and traces between four wells within the Milne Point Unit and five wells within the Kuparuk River Unit.

This quotation is also significant because of its use of the A-1 well as the type well. Although well logs from 1989 G-1 well (the claimed discovery well) were available, Conoco chose well logs from the nearby 1982 A-1 well for purposes of discussion of the geology.

The December 14, 1989 submission also correlates the nomenclature used by Conoco in describing the SOS with the nomenclature used by ARCO in describing the West Sak and the upper Ugnu in the Kuparuk River Unit. See second paragraph of the first page, and Figure 2.

The November 1990 submission also correctly encompasses the entire SOS, including West Sak, in its discussion of the geologic structure for which the discovery is claimed. While both the December 14, 1989 and the November 1990 submissions lend support to the conclusion that the SOS is separate from the Kuparuk Formation and the Prudhoe Bay field, they do not support the conclusion that the SOS in the Milne Point Unit are part of a geologic structure that is separate from the previously drilled and tested West Sak or the other SOS intervals previously drilled and tested within the Milne Point Unit.

O Information submitted in support of royalty reduction

In support of its efforts to obtain a royalty reduction for production from the Milne Point Unit (separate from this discovery royalty application), Conoco previously submitted to the Division a copy of a Conoco document entitled "Initial Development Plan for the Shallow Oil Sands in the Milne Point Unit." This document, prepared in 1985 (four years before the G-1 well was drilled), described the "wealth of information" that had been compiled and analyzed about the SOS. Page IV-1. While the document concluded that there was a need for further delineation, it nonetheless described the geology, made estimates of oil in place, and described production methods and scenarios. See, e.g., pages II-1 and II-2.

Tellingly, four years before the G-1 well made what Conoco claims is the "first discovery" of the Shallow Oil Sands, Conoco had developed a "Shallow Oil Sands Development Philosophy":

The shallow oil sands have always been targeted for development after the Kuparuk zone was fully developed and excess facility capacity became available.

Conoco misapprehends the "commerciality" issue.

In the "Pre-drilling Expectation and Post-drilling Verification" discussion submitted with the December 7, 1989 application for discovery royalty certification, Conoco appears to suggest that risks relating to "completion and producing techniques, and crude price and perceived price stability" are somehow pertinent to the issue of whether Conoco's G-1 well made the "first discovery of oil or gas in commercial quantities in a geologic structure." I disagree for the following reasons.

First, the statute and lease term speak in terms of commercial quantities. The basic information about the quantity and quality of hydrocarbons was known before the G-1 well was drilled. As noted above, the well only resulted in "minor" or "slight" adjustments to Conoco's pre-drilling estimates. In short, there is nothing about the drilling of the asserted discovery well that could be characterized as a discovery of a heretofore unknown quantity of oil.

Second, Conoco argues that no well has been certified as capable of producing in "paying quantities" prior to the G-1 well. This argument is irrelevant. There is no evidence that any other party has ever sought a "paying quantities" determination for a well targeted for the SOS. Moreover, the "paying quantities" determination is made only for particular purposes, unrelated to the discovery royalty issue. See, e.g., Pan American Petroleum Corp. v. Shell Oil Co., 455 P.2d 12, 23-24 (Alaska 1969).

Third, the risks Conoco faces in putting the SOS into production are production related, not discovery-related risks. Conoco stresses the "costs of continued experimentation with completions, the risks concerning oil prices and transportation costs." While these are genuine risks, they are not discovery risks, were not unique to this well, and the G-1 well did not resolve those risks.² These

² Conoco explicitly states that the "[p]roduction history also verified that the completion technique utilized in G-1 will not provide the long term completion needed for full scale development. Additional experimentation with completions will be required before economic development is a reality." Thus the G-1 well, besides not being the discovery well for the SOS, did not resolve all production-related impediments either. It is just as clear that there is no nexus between the G-1 well and the resolution of other risks. Nothing about the drilling of the well could possibly affect future taxes, oil prices, and the like.

kinds of risks are common to all development projects. The discovery royalty was designed as a reward for undertaking discovery risks, not development risks. Conoco's 1985 "Initial Development Plan for the Shallow Oil Sands in the Milne Point Unit" and attachment to its December 7, 1989 discovery royalty application demonstrate that the development decision was a matter of timing (in relationship to the production from the Kuparuk Formation), oil prices, transportation prices, taxes, completion and production techniques and other such issues. In other words, actual development was determined by factors unrelated to any discovery efforts made by means of the G-1 well.

The statute was changed to explicitly focus on discovery rather than commercial production.

The Territorial Legislature enacted royalty provisions in 1955 that provided for issuance of oil and gas leases

with a royalty fixed by the Commissioner, with the approval of the Attorney General and the Commissioner of Mines, at not less than five percentum (5%) the first ten years of new production, and twelve and one-half percentum (12½) each year thereafter

Sec.3, ch.189 SLA 1955. Emphasis added.

In 1957, the incentive was limited to the first producer in a new area. The statute provided, as a general rule, for a floor of 12 1/2%, with the following proviso:

provided that a royalty of not less than five percentum (5%) for the first ten years will be allowed the first producer in a new area.

Art. IX, sec. 2, Ch 184 SLA 1957.

In 1959, the legislature rejected the earlier incentives triggered by commencement of production, and restricted the five percent royalty to the lease upon which a "first discovery of oil and gas in commercial quantities in a separate geologic structure" is made. Section 7, ch. 169 SLA 1959. This leaves no room to award a discovery royalty in this case. The risks and costs of commencing production (whether "new production" generally or as the "first producer in a new area") were rejected by the legislature as a basis for a reduced royalty. The legislature replaced an incentive

tied to commencement of production with an incentive tied to "first discovery." The division has no authority to attempt to circumvent that clear intent.

CONCLUSION

The intent of the repealed statute was clearly to provide an incentive to discover and place on production new fields in previously untested structures. The statute foremost required the holder of the lease to "drill and make the first discovery" in a geologic structure (AS 38.05.180 repealed). Conoco exposed the fact that the G-1 well is not a discovery well in the attachment to its December 7, 1989 application by stating "The risk of geologic nonsuccess for the shallow oil sands at Milne Point is small."

Accordingly, the Milne Point G-1 well clearly does not meet the criteria for a discovery well. This well penetrated the Shallow Oil Sands in a geologic structure that had been discovered and determined to be productive over 20 years ago. Since 1969, the SOS has been penetrated and been found to be a hydrocarbon reservoir by hundreds of wells in the same geologic structure. Therefore, it is clear that the Milne Point G-1 fails to meet either the requirements or the intent of the repealed discovery royalty statute.


James E. Eason
Director

WALTER J. HICKEL GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

P.O. BOX 107005
ANCHORAGE, ALASKA 99510-7005
PHONE: (907) 782-2481

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

January 16, 1992

DECISION

Conoco, Inc.	:	Oil and Gas Lease
Suite 200	:	ADL 25906
3201 C Street	:	Milne Point Unit
Anchorage, Alaska 99503	:	

DECISION AFFIRMING DIRECTOR'S DENIAL OF DISCOVERY
CERTIFICATION BASED ON MILNE POINT UNIT G-1 WELL

I have carefully reviewed the decision ("Decision") of the Director of the Division of Oil and Gas denying a "discovery royalty" to Conoco, Inc. ("Conoco"). The Decision concludes that Conoco's G-1 well in the Milne Point Unit did not qualify the lease for an award of the reduced "discovery royalty" rate because the well did not make a "first discovery of oil or gas in commercial quantities in any geologic structure." In essence, the Decision concludes that both the existence of the geologic structure (referred to variously as the "Schrader Bluff Formation" the "West Sak," and the "Shallow Oil Sands" ("SOS")) and the quantities of oil accumulated in the structure were known prior to the drilling of the well. The Decision determined that it was most accurate to describe the G-1 Well as "Conoco's first planned production well within the SOS" (Decision at 4, emphasis added), not as a "discovery well."

I have also carefully reviewed Conoco's appellate brief. Conoco does not deny that the structure had previously been discovered through the drilling of other wells, and that prior exploration had yielded confirmation that the structure contained a large accumulation of oil. Brief of Appellant ("Br.") at 1-2, and 3 at n.1. See also Affidavit of Alan Hastings, paragraph 10 ("Hastings Aff."), where it admitted that in 1985, four years before the G-1 Well was drilled, a study by the Milne Point Unit had estimated that there were "over 366 million barrels of oil in place" on the lease at issue alone. In light of this admission that the G-1 Well broke no new exploration ground, it is not surprising that Conoco tries to diminish the significance and common sense meaning of the "discovery" requirement. Thus, Conoco argues that the key requirement is not a discovery at all, but rather the mere drilling of the first well that establishes "commercial quantities." The term "commercial quantities" is, in turn, equated with actual

**Decision Affirming Director's Denial of Discovery
Certification Based on Milne Point Unit G-1 Well
January 16, 1992**

"commerciality" (Br. at 4, 1.1) and "capability of commercial production" (Br. at 2, 11.14-15, emphasis added).

My review of the record of this appeal, and a common sense application of former AS 38.05.180(a) and the lease to the facts, compel me to affirm the Decision of the Director.

The former statute and regulations intended to encourage the discovery of new oil bearing structures and once a new discovery is made, to encourage rapid development of and production from the structure.

The plain language of AS 38.05.180(a) shows that the legislature intended to encourage drilling to discovery previously unknown oil bearing structures and once a discovery is made, to encourage rapid development of and production from the structure. "Discover" means to "be the first to find, learn of, or observe." Am. Her. Dictionary 376 (1970). In this instance, it means to find an oil bearing structure, not previously known. This requirement is emphasized by the term "first discovery." Importantly, the statute ties the finding with "drill(ing)". Thus, the statute obviously seeks to encourage exploratory drilling. The statute also plainly encourages rapid production by limiting the reduced rate to a ten year period following the date of discovery.

The Alaska Supreme Court has stated that the former regulations implementing the statute specified the three elements required by the statute for discovery well certification: date of discovery, commercial quantities, and geologic structure. See Union Oil Co. v. State, 574 P.2d 1266, 1269 (Alaska 1978). The regulations suggest that these elements are separate and distinct, and can be established at different times. When read as a whole these regulations foster the dual purposes of the statute—to encourage exploratory drilling and rapid production.

The regulations define the date of discovery element as the date that an operator first finds oil or, in the exact of language of the regulations, "first encounters sufficient evidence of oil or gas in a particular geologic structure". 11 AAC 83.200. This event starts the running of the ten year reduced rate period. 11 AAC 83.215. At this point, the operator is not required to show that the evidence is sufficient to prove production in commercial quantities, only that the evidence is enough to cause the reasonable operator to continue operations. In order to preserve his priority, he must provide a sworn statement of the first encounter within thirty days of the encounter.

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Certification Based on Milne Point Unit G-1 Well
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The regulations do not require the operator to provide evidence of the second element, commerciality, until later. This is consistent with the reality that an operator first encounters or discovers oil, and then tests or evaluates a find to determine whether it is commercial. See Shoni Uranium Corp. v. Federal-Radrock Gas Hill Partners, 407 P.2d, 712 (Wyo. 1965) ("Upon the discovery . . . there was an implied obligation on the part of the lessee to do whatever was necessary under the circumstances (1) to ascertain whether the deposit existed in commercial quantities; and (2) thereafter to reasonably develop") (deletions in original). The regulations provide that the operator must continue to work diligently to "complete a well in the discovery zone . . . that can be tested for . . . commercial quantities." 11 AAC 83.210. The second event occurs when the operator establishes commercial quantities. 11 AAC 83.210(b)(1).

The third event occurs when the operator establishes that the discovery is in a separate geologic structure. This can occur up to ninety days after the date of the commercial quantities potential test.

Conoco's argument equating the "first to drill and discover oil" with the "first to produce oil" is inconsistent with the statute's plain language and would frustrate its purposes.

The director denied Conoco's application because he found that the G-1 well was not the first well to discover oil in the SOS structure. Both the East Ugnu No. 1 well and the A-1 well had encountered oil long before the G-1 well. Conoco argues that the discovery requirement and the commercial requirement should be collapsed into one test. It asserts that who discovered the oil is irrelevant. Br. 8. According to Conoco, in order to be the discovery well, the well itself must be shown to be "capable of production in commercial quantities." Br. 8.¹ Thus, discovery

¹ I need not address whether the repealed regulations are binding or not. Conoco's argument, which is premised on the regulations continued validity and on Conoco's interpretation of former 11 AAC 83.205(1) which defined "discovery," ignores the entire context of the regulations and is nonsensical. Under the regulations, the first or initial discovery of a discovery zone in a structure is the first encounter. 11 AAC 83.210. The commercial quantities test of the zone may be demonstrated in the first encounter well or a later well in the same structure. 11 AAC 83.200-.215. By misinterpreting 11 AAC 83.205(1), Conoco would
(continued...)

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depends not upon new knowledge of an oil-bearing structure acquired through drilling, but upon technological improvements, new tax benefits, projected oil price, and the operator's internal economics. See App. Br. 3; Affidavit of Harold D. Haley at 3, paragraph 6.

Conoco's interpretation would change the statutory language whoever "drills and makes the first discovery" to whoever "first completes a production well." The Decision pointed out, this would in essence make the statute read as it formerly did in the territorial days. It would reward purely production risks as opposed to discovery and production risks. As discussed in the preceding section, discovery royalty was intended to reward those who successfully undertook the geologic and economic risks associated with exploration tied to rapid development. While oil prices, cost of production, and efficiency of production influence when an accumulation of oil may be brought into production and what level

¹(...continued)

require that both discovery and commercial quantities be proved in the same well. Br. 8-9.

Conoco's incorrect reading of 11 AAC 83.205 ignores the provisions of 11 AAC 83.200, .210, and .215, all of which contemplate that discovery and commercial quantities may be shown at different times and in different wells. Reading 11 AAC 83.205(1) consistently with these other provisions, "first acceptable evidence in a drilling well of the existence of oil or gas" refers to the first encounter while the modifying clause "which can be produced in commercial quantities after well completion" refers to the requirement that a well in the structure must meet the commercial quantities test. It is noteworthy that 11 AAC 83.205 does not require that the well which provides the first acceptable evidence be tested or produced. 11 AAC 83.205(1) refers to whether the structure can be produced in commercial quantities and refers to a future test in some well, not necessarily the well providing the first acceptable evidence of oil. The commercial quantities test only confirms that the first encounter has met the statutory requirement of a "discovery of oil or gas in any geologic structure." AS 38.05.180(a) (emphasis added). This is consistent with the division's and industry's twenty year history with discovery royalty that "discovery occurs upon the first encounterment of oil and gas, not upon the date of a drill stem test confirming the extent of the discovery of oil and gas." See Niakuk 34635 No. 5 Certified as Discovery Well ADL 34635 Conditionally Granted Five Percent Discovery Royalty (September 2, 1988) at 5.

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of profits or loss the producer may enjoy, they do not determine when a "discovery" has taken place, or change the quantity of oil that has been discovered. Conoco's interpretation would frustrate the statute's dual purposes.

Conoco's interpretation would allow the operator to choose his discovery well and thereby manipulate the date of discovery to frustrate the rapid production intent of the statute. Since the ten year reduced rate commences on the date of discovery, an operator, who encountered a good show of oil, could delay the commencement of the period by delaying completion of testing of commerciality to coincide as closely as possible with the initiation of actual production.

Conoco's interpretation would also lead to absurd results as illustrated by a hypothetical example. Assume that lessees A and B purchased adjoining leases over the same prospect. However, only lessee A undertook the costs and risks of exploration, discovering a large accumulation. Assume, however, that the low quality of the oil and the high cost of production rendered it uneconomic to produce the accumulation at forecasted oil prices. Further, assume that after the results of lessee A's discovery efforts became public, a war in the mideast caused large price increases. Finally, assume this causes both lessee A and lessee B to commence drilling in order to produce oil from this known accumulation. Under Conoco's theory, lessee B would be credited with making the "first discovery of oil in commercial quantities in a geologic structure" if it were first in completing its well, despite the fact that lessee A had actually undertaken the discovery risks some years earlier, and lessee B did nothing except more quickly respond to a changed economic opportunity. This makes no sense.

The decision in Joseph I. O'Neill, Jr., 77 Interior Dec. 181, IBLA 70-39 (1970), supports my interpretation. In that case an argument similar to Conoco's argument that "discovery of oil and gas in commercial quantities" means "a well that is capable of production in commercial quantities" was rejected by the federal Board of Land Appeals. The Mineral Leasing Act provided that leases segregated from a primary lease would be extended for two years from the date of "discovery of oil or gas in paying quantities" upon any other segregated portion of the lease. The Board of Appeals rejected an argument that a well capable of producing oil or gas in paying quantities was required before an extension would be granted. After stating that "discovery" means "to find something not known before" the Board refused to read into the statute a predicate of a well capable of producing in paying quantities. *Id.* at 61. It

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stated that if Congress wanted to impose such a requirement, "it could have easily so provided. It did not." *Id.* at 62.

Likewise, had the legislature intended to reward only production, it could have easily awarded a reduced royalty to the first producer in the structure like the Territorial legislature did. But, it did not. I will not equate discovery with production.

As explained in detail in the Decision, the G-1 well did not make the first discovery of oil and gas in the SOS structure.² Conoco knew not only of the existence of oil bearing structure, but also the supergiant size of the accumulation, before it drilled. It did not bear any exploratory risk.

Even if Conoco's argument was correct, it would not be entitled to discovery royalty because previous wells demonstrated commercial quantities.

The G-1 well was hardly the first well into the SOS that yielded "acceptable evidence" of commercial quantities in the discovery zone. As explained in the Decision, many wells, including Conoco's own A-1, B-2, A-3, and N-1B wells, drilled and tested earlier in the SOS yielded that evidence. I find that the flow rates from potential tests in several of Conoco's earlier wells yielded acceptable evidence that oil could "be produced in commercial quantities." Furthermore, Arco's pilot program in the SOS structure demonstrated that the structure was currently commercial,

² Conoco cites two other discovery royalty applications in support of its idea that "first discovery" is different from "first encounter." Neither of the cited cases assist Conoco. It is true that Point McIntyre No. 3 was certified despite the fact that earlier wells had penetrated the structure. However, it is clear that merely penetrating the structure does not constitute a first discovery. In the case of Point McIntyre, the operators of the wells making those earlier penetrations (the Point McIntyre No. 1 and No. 2 wells) failed to acquire sufficient evidence of a discovery before abandoning the wells as dry holes. Such corroborative data might have included open-hole logs, tests, or core data from the discovery intervals. This sharply contrasts with the circumstances extant with Conoco's knowledge regarding the SOS, where over a billion barrels of oil were known to exist from prior exploratory drilling.

In the case of the Sag Delta No. 3 well, it encountered no productive interval at all.

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albeit only marginal. See DeRuiter, Nash & Wyrick, Solubility and Displacement Behavior of Carbon Dioxide and Hydrocarbon Gases with a Viscous Crude Oil, SPE 20523 (1990).³

Conoco argues the failure of any previous owner to undertake commercial development demonstrates that the previous wells did not discovery commercial quantities. First, the fact that no earlier lessee applied for certification is irrelevant. Br. at 7-8. The issue is not whether others could have qualified, but whether Conoco does. Second, the other's failure to develop is not surprising, given that the owners' decision to develop the underlying more economic Kuparuk structure first for their own internal reasons.

Even under Conoco's interpretation of "discovery" any benefit from discovery royalty would have expired before the drilling of the G-1 well.

I have previously stated my opinion that the first encounter well is the discovery well. Even if I accepted Conoco's argument that the first well to produce was the discovery well, the first encounter would nevertheless start the running of the ten year reduced royalty period.

Both regulations 11 AAC 83.200 & 210 refer to the first encounter of oil and gas. 11 AAC 83.210 states

to establish priority as to the time and date of discovery, an operator must furnish the committee with a sworn statement and substantiating evidence acceptable to the committee that oil or gas has been encountered in sufficient showing to cause a reasonable and prudent operator to conduct further operations in an effort to complete a well in the discovery zone so that the well can be tested for potential oil or gas production in commercial quantities. The statement must include the time and date of first discovery . . .

³ Conoco misunderstands the commerciality test as defined in the regulations. Conoco would require actual commercial development as the only method of satisfying the commercial quantities test. Br. 5. The regulations only require a potential test which would in the future lead to one additional well with a reasonable profit if a market existed. 11 AAC 83.205. No actual development is required.

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It is clear that "first discovery" refers to first encounter in this regulation.

Regulation 11 AAC 83.215 states that "the date of commencement of the 10 year-5 percent discovery royalty term shall be the first of the next month after the established date of initial discovery." It is clear that "initial discovery" in this regulation refers to the same event referred to in 11 AAC 83.210 as "first discovery," namely first encounter of the discovery zone. 11 AAC 83.215 bases the date of initiation of the 10 year reduced royalty on this date, which is distinct from the date in which a well establishes oil in commercial quantities. Both the division and the industry have consistently accepted that the ten year period begins to run from the date of first encounter, not confirmation or establishment of commercial quantities. See Niakuk, supra at 5. Therefore, even if I were to accept Conoco's claim that the G-1 well established commercial quantities in the SOS structure (which I do not), the date of commencement of reduced royalty would be controlled by the date of first encounter. Indisputably the date of first encounter or initial discovery of the SOS occurred more than ten years prior to the drilling of the G-1 well and subsequent initiation of SOS production ADL 25906. Therefore, none of the production from this lease would be entitled to a reduced royalty.

Conclusion:

The discovery royalty expressly rewards the one who makes a "first discovery," not the one who is "first into production." I know the difference between discovery and production. Conoco knew when it drilled the G-1 well what the structure was, and, to a high degree of precision, the quantity and quality of the oil accumulation that would be encountered. Conoco faced not the risks of a dry exploration hole, but the economic risks associated with taking someone else's discovery into production. It is not my role as lease manager on behalf of the citizens of the state to transform the discovery incentive into solely a production incentive. Therefore, I affirm the Decision of the director.


Harold C. Heinze
Commissioner

ENCLOSURE 28

MONTHLY SAVINGS ATTRIBUTABLE TO THE DISCOVERY ROYALTY PROVISION

Example Month: JULY 1994

<u>Field</u>	<u>Savings</u>
Niakuk/Lisburne	\$198,768.00
Point McIntyre	\$534,118.00
North Prudhoe Bay	<u>\$ 51,587.00</u>
TOTAL	\$784,473.00.

Dept. of Revenue

New Revenue Commissioner Wil Condon says his job is to make "this place work." Major policy will be left to Gov. Knowles, he says. Condon also believes that many of the big areas for disagreements with oil and gas taxpayers will soon be behind us. He believes the new tax regulations will help. Page 2

Cook Inlet

Unocal says "external" regulatory factors like potential new effluent discharge restrictions and escort tug requirements could shorten the economic viability of many Cook Inlet platforms. Page 7

Air Quality

Officials in DEC's air quality division are concerned that permit fees under the new Title V program may not be sufficient to meet costs, and are looking at ways to streamline administration. Page 6

Water Quality

Alaskan municipalities and resource industries, including oil and gas, are gearing up for another round on those new water quality standards. Meanwhile, DEC is adding new "anti-degradation" language to meet EPA requirements, including a new water body classification — "outstanding national resource waters." Page 7

INSIDE

OIL & GAS

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Lawmakers look at ideas for new development incentives

State legislators in Juneau are looking at how new fiscal incentives might strengthen Alaska's ability to attract new oil and gas investment, a problem highlighted in a recent study on competitiveness by consultants Gaffney, Cline & Assoc., for the State Dept. of Commerce and Economic Development. The Senate Resources Committee, chaired by Sen. Loren Leman, held hearings Feb. 1 to hear industry's views. House Resources Committee, chaired by Rep. Joe Green, will take up the subject Feb. 15. Here are excerpts from the Senate Resources hearing:

ARCO:

No tax changes on existing production; new tax and royalty approaches should be considered on marginal fields

ARCO Alaska President Ken Thompson said his company would not ask for tax or royalty changes on existing production on the North Slope, "because we know the state depends on these revenues ... We are asking, however, that there be no new tax increases on existing production," considering there have already been 13 increases since just prior to Prudhoe Bay start-up, he said.

But ARCO does believe that, "for new investments in marginal or noneconomic reservoirs in existing fields, and for small to moderate-sized new field discoveries, new tax and royalty changes should be considered to make investments competitive."

"But before new ideas can be discussed, it is so important to realize that first, our industry and the government must learn to better trust each other and to have more open communication...we need a true 'partnership' relation."

BP:

Tax clarity reduces risk at no cost to the state; suggests sliding scale royalty pegged to oil prices for Badami

BP Exploration (Alaska) Inc.'s Director of External Affairs Jim Palmer noted that Alaska's industry has gone through "an extended period of unprecedented change,

Continued on Page 3

INSIDE: Department of Revenue

Condon: 'My job is to make this place work'

New state revenue commissioner Wil Condon says administering state taxes more efficiently and effectively is the best contribution the Department of Revenue can make toward Gov. Tony Knowles' goal of an improved business climate in Alaska. "My job is to make this place work," he says. If the governor or legislators want to examine policy options, for example, in response to the state's pending fiscal gap, "we want to make sure they have the tools to do it with," he says. "I'm not in the vision business." Broad policy initiatives will be left to his boss, Gov. Knowles, and to legislators.

There are, however, issues one level down from the broad policy arena the department will be working on. New oil tax regulations that went into effect at the start of the year will resolve many problems in tax administration, but there are some remaining issues the department, and the petroleum industry, are committed to resolving, Condon says.

A priority will be for the Division of Oil and Gas Audit to complete its work on long-standing oil and gas tax disputes. A goal of Condon's is to enable the state and industry to identify disagreements early and to resolve them quickly.

From now on, auditing and resolving issues in oil and gas taxes should move more smoothly and quickly, Condon explains.

The new commissioner says there are two reasons: First, new tax regulations will help resolve complex problems created by crude oil being sold in distant, and different, markets, he says. The state and industry agree that Alaska's oil tax situation is unique: Alaska is a big producer, but unlike long-standing traditional producing areas like Texas, relatively little crude oil is actually sold in the state. Because most of Alaska's oil is sold elsewhere, and in different markets (west coast, gulf coast), there will always be some disagreements over the relative values of oil transactions and transportation costs. The department has been wrestling with this for 15 years, Condon says, but the new tax regulations will help considerably.

Secondly, many past-year tax disputes arose out of disagreements between the industry and state as to how crude oil was to be valued during years when federal price controls set the price at which domestic oil, including Alaska, could be sold. "That was a perfect recipe for a 15-year, \$5 billion tax dispute," Condon says. Once the "books" are closed for those years, the department's auditors will be working in tax years when market prices more clearly set the value of oil, which should reduce potential for

disagreements.

Condon has been in private law practice in Anchorage and was deeply involved in the state's effort to litigate oil and gas royalty issues, including the subsequent settlement of the so-called "Amerada Hess" case, as well as in more recent tax disputes. He was State Attorney General from 1980 to 1982, Deputy Attorney General from 1975 to 1980, and was an Assistant Attorney General from 1971 to 1975. He received his undergraduate and law degrees from Stanford University.

Alyeska moving on audit items; 85%-90% completion in 1995

Alyeska Pipeline Service Co. completed 70 percent of the 4,900 work items identified under the federal audit by the end of 1994, and plans to have all the electrical items and 85 to 90 percent of all other work completed by the end of 1995, according to Doug Webb, Alyeska's public affairs vice president. Speaking at the Resource Development Council in January, Webb said Alyeska had mobilized about 1,000 people to work on the program during 1994.

Webb also said Alyeska has committed about \$100 million to \$125 million to 1995 capital projects.

The Alaska Oil and Gas Association is a private, non-profit industry trade association. Its members are companies engaged in oil and gas exploration, production, refining and marketing activities in Alaska. AOGA serves as a forum for its members to coordinate common public and government affairs efforts.

The AOGA newsletter, Inside Oil and Gas, is an informational publication published twice monthly, intended to update and advise its members and interested individuals on issues of interest. The views and opinions expressed in the newsletter do not necessarily reflect the views or opinions of individual AOGA member companies. Unless specifically stated as such, no opinions, views or positions in the newsletter are AOGA opinions, views or positions. Alaska Oil and Gas Association, 121 West Fireweed, Suite 207, Anchorage, Alaska 99503. Phone: (907) 272-1481. Judy Brady, Editor.

Incentives: Tax clarity, fiscal gap also important

Continued from Page 1

often painful ... in order to remain competitive in the global market."

"As a result, we've been able to reduce costs in a climate of declining production. We've been able to hold overall production decline on the North Slope to less than 5 percent a year... by continuing to invest in new and existing fields on the North Slope," Palmer said. At the same time, a world of new investment opportunities has caused companies to limit the scope of their activities and become increasingly selective in choosing which project to pursue, Palmer said. Alaska has already made gains in reducing risk by resolving past tax disputes, and enacting new tax regulations. "Tax clarity for all producers would reduce our risk at no expense to the state," he said.

But additional measures may be needed to compete for capital for marginal projects. For example, BP has suggested, for discussion purposes, a sliding-scale royalty pegged to oil prices for the Badami discovery east of Prudhoe Bay.

Exxon:

First tackle fiscal problem; second, improve administration of tax regulations

Exxon U.S.A.'s Alaska Production Manager Jim Branch told the committee his company felt state fiscal reform, tax and regulatory stability and clarity, and improved cooperation between the state and industry "are the most important initiatives that will have the greatest positive impact on investor perception and confidence in our state."

"First, the most important message the state can send any potential investor is that the budgetary problems that have plagued the state in the past are being corrected," Branch said. "Second, the state should improve the administration of its tax regulations to provide clarity, predictability and reasonable balance in the interests of both the state and the taxpayer."

These objectives addressed, Exxon does believe "well-designed exploration and production incentives have a role in enhancing the specific project, but any incentive should increase overall state revenues, not just subsidize one field at the expense of another. The incentive should have general applicability to all members of industry on a consistent basis."

"The state and all of industry wins when a well-designed incentive 'makes the pie bigger' without penalizing someone else in the process," Branch said.

UNOCAL:

Reduce or eliminate royalty on marginal producing property to extend platform life; regulatory issues critical to Inlet production

Unocal's Alaska Land Manager Kevin Tabler, now the major Cook Inlet offshore operator, said "we are at a critical juncture in the continued development of the existing producing fields in Cook Inlet," Tabler said. "We need to create a more favorable climate to eliminate uncertainty." Tabler said the state could help ease major economic uncertainties for Inlet operators, caused mostly by regulatory issues like facility abandonment requirements and discharge limitations.

"Reducing or eliminating the state's royalty on ... marginal properties could make the projects economically viable and significantly increase the economic life of the platforms, thereby maintaining employment and the associated community benefits," Tabler told the committee.

As for fiscal incentives, Tabler suggested there were many options, including reduced royalty being tied to future development in the same field or area and royalty could be reduced on new field exploration until payout. "The recovery of capital costs by the investing party before the non-investing party participates is a standard in the industry and a solid concept in joint-venture partnerships," he said.

Tabler also urged the state to broaden application of exploration incentive credits, which are already on the books. "Amendments to make them more accessible or usable would encourage investment," he said.

Marathon:

Cook Inlet producers to work on consensus approach to incentives; state should consider an independent appeal process for tax disputes

Marathon Oil's Alaska Region Manager Ralph Dartez said his company is working with other Inlet producers to identify a "consensus approach" on incentives that might work in the Inlet and Kenai Peninsula. Dartez complimented the Dept. of

Continued on Page 6

Alaska Oil & Gas Taxes



CURRENT TAXES:

Income Taxes: **9.4% Corporate Income Tax**
Property Tax: **20 mils/2% of assessed value**

Severance/Production:



GAS

10% of Market Value or \$0.064 per MCF,
whichever is greater.



OIL

12.25% of Market Value for first five years,
15% after first five years or \$.80 per barrel,
whichever is higher.



OIL

Oil & Gas Severance Taxes subject to
Economic Limit Factor (ELF). *See next page.*

Conservation Tax:



GAS

4 tenths of a percent per 50,000 cubic
feet of natural gas.



OIL

4 tenths of one percent per barrel with
conservation surcharge of \$0.03 and \$0.02 per
barrel of crude oil to fund Oil and Hazardous
Substance Release Prevention and Response
Fund (\$0.02 per barrel surcharge suspended
when Response Account balance equals
\$50 million.)

Alaska Oil & Gas Incentives

Economic Incentives: PRODUCTION/ DEVELOPMENT



Economic Limit Factor - AS 43.55.013

The respective severance tax rates for oil and gas are reduced by a field's ELF. During the life of a field, production expenses must be less than operating costs. If the economic limit, total costs including operation costs, royalties and production taxes exceed gross revenue and the field becomes uneconomic. Production tax rates for each individual field are modified by the economic limit factor (ELF) which is a value between zero and one. The ELF is a factor which is multiplied by the nominal production tax rate to derive an effective production tax rate for each field. The ELF varies based upon a field's size, as measured in total throughput, and by the field's average per well productivity.

Co-Mingling - 15 AAC 55.027

...of the new production tax regulations (effective Jan. 1995) allow producing fields to share facilities while maintaining each field's "distinct field" status for ELF purposes. Three "sets" of fields are currently sharing facilities. Section 027 of the new regulations provide for appealing Department of Revenue's de-

cision if an application is denied. The Commissioner of Revenue makes the ultimate decision.

Non-Taxed Produced Gas - 15 AAC 55.151 (e)

...of the new production tax regulations allow free use of gas for enhanced recovery purposes.

Royalty Reduction - AS 38.05.180 (j)

After two years of lease production, royalty may be reduced to prolong economic life of a field. Lessee must show revenue is insufficient to yield a reasonable rate of return. DNR commissioner has authority to approve royalty reduction.

EOR Credit - Code Sec. 43

Federal Enhanced Recovery income tax credit deduction may be claimed on state income tax. May be taken as a line item deduction on state income tax return. Department of Revenue does not have compiled information on number of companies or amount of credits claimed or allowed.

Industrial Incentive Credit - AS 43.20.042

Credit of 10% of cost for gas processing projects applied against income tax. May be taken as a line item deduction on state income tax return. DOR does not have information on the number of companies or amount of credits claimed or allowed. Through the audit process claims can be contested or

denied. Appeals are handled through the existing appeals process i.e., informal conference and formal hearing process. The Commissioner of Revenue ultimately signs the findings of the formal hearing.

Discovery Royalty Credit - AS 38.05.180 Repealed by Chapter 65 SLA 1969

Provides that a lessee who makes first discovery of oil or gas in commercial quantities in a geologic structure pay a royalty of five percent for 10 years following the date of discovery and 12.5 percent royalty thereafter. Some leases issued up to the point of repeal could still qualify.

Economic Incentives: EXPLORATION



Exploration Credits: AS 38.05.180 (i)

Provides for a credit of up to 50% of certain exploration costs that can be applied against royalty, rentals and severance taxes due the state. This provision is accomplished by state leases. Covers two years following the lease sale and applies to well footage drilled and geophysical costs. Geophysical data must be made public. EIC has been offered in 10 sales. Credits have

been granted on 20 EIC wells. 11 AAC 83.820 defines the process for appeal to the DNR Commissioner, who makes the final decision.

NEW EXPLORATION INCENTIVES



Exploration Incentive Credits - AS 41.09.100

Provides for a credit of \$5 million per project (total of all credits \$30 million) for geophysical work, exploration or strat test wells. Credit may be applied against taxes or bonus payments. Credit may not exceed 50% of eligible costs on state-owned land and 25% on land not owned by the state. Credit must be used within 5 years and may be assigned. Data confidential for 24 months. Status - Regulations pending.

Exploration Licensing AS 38.05.132

Provides for licensing of up to 500,000 acres conditioned upon an obligation to perform a specific work commitment. (Maximum acres which can be held under license 2 million acres.) Gives licensee option to convert to lease upon completion of work commitment. Status - Regulations pending.

DEC's air program: Can its costs be cut?

Department of Environmental Conservation's air quality group is wrestling with the problem of how to get the Title V program costs within projected revenues to be received by the new \$78 per hour processing fee and \$5/ton annual "emissions" fee (federal law requires fees to cover total costs of the program). With the regulations, and the new program now in the approval process, targeting an effective November implementation (assuming EPA approval), DEC now has a better handle of what the program will cost. If the program is managed similar to the existing air program, costs would increase from the original estimate of \$3 million per year to an estimated cost of \$5 million. DEC officials say part of the reason the costs are higher is because some "overhead" items were not included in the original estimate, such as public information and complaint-response activities.

Changes possible in hourly fee or annual per-ton emissions fee, agency says

DEC adds that if \$5 million were to be covered by higher fees, substantial increases in either the hourly charge or the per-ton charge, or some combination of both, would be needed. The first task, officials say, is to take a hard look at how the air quality group runs things to see if efficiencies can be gained. For example, some personnel in field offices are in so-called "rainbow" positions with jobs split among several functions (air and water quality, solid waste, oil pollution, etc.). It might make more sense (and the accounting would be easier) to have people purely dedicated to working air permits, officials say.

Marathon, Texaco suggest state should be more open to existing incentives

Continued from Page 3

Revenue's progress in defining taxable value, but said "we believe development of an independent appeals process for tax disputes could ultimately provide a means for reducing uncertainty for the taxpayer." As for royalty reductions, Dartez said Title 38 already delegates some authority to the Dept. of Natural Resources, "to consider royalty reductions for fields where weak economics threaten the future life of the field. We would like the state to review the statute and how it has been administered historically." Future requests should be considered, "more openly and aggressively," he said. Marathon views future exploration opportunities as small to moderate in size. "Economics ... are likely to be dependent on availability of existing infrastructure. Therefore, it is critical that new discoveries be made soon, before existing infrastructure surpasses its economic life," Dartez said. Land access is still the number one concern. "We appreciate the efforts of the legislature last year in passing Senate Bill 308, which provides more certainty to the lease sale process," he said.

Texaco:

Allow industry to use current incentive programs

Texaco USA's Alaska Land Manager Pete Nelson said the interest in incentives was, "very timely in terms of the current low ebb of exploration and production of marginal fields, declining Prudhoe Bay production and the beginning of an opportunity with the new administration to make things better." Nelson, herself a 19-year veteran with the State Dept. of Natural Resources, complimented the legislature with having done a pretty good job in passing incentive measures, and the executive branch in writing regulations to implement the legislation. "However, recent administrations have lacked the desire and motivation, and therefore the appropriate policy, to encourage or even allow industry to fully use these incentive provisions." Nelson cited two examples of problems from Texaco's experience, one a marginal Cook Inlet producing property where the company applied for royalty reduction, and second, an Exploration Incentive Credit applied on a North Slope exploration well.

Small companies look at ways to make Alaska more competitive

Small companies working in Alaska also commented at the hearing. Dan Donkel, president of Danco Exploration, Inc., suggested a holiday on royalties on new wells drilled until investment "payout" is achieved; more effective ways of resolving disputes between companies and the state; and a "one-stop" permitting process for oil and gas companies. Bill Stewart, president of Stewart Petroleum, suggested the five percent "discovery" royalty, repealed by the state in 1970, be reinstituted; that ways be found to make more acreage available for exploration, permitting be simplified, and that oil spill bonding requirements, which work a particular hardship on independents, be eased.

Discharge limits, rules on tugs threaten Inlet

Mature oil and gas fields in Cook Inlet are uniquely vulnerable to "external" influences, such as changes in effluent standards, requirements for tanker escorts, and state facility abandonment requirements, Unocal Alaska Land Manager Kevin Tabler told the Senate Resources Committee Feb. 1. "Any one of these external influences significantly impacts the economic viability of our operations and accelerates field abandonment." Four of the 10 inlet producing platforms operated by Unocal produce less than 2,000 barrels of oil daily. Unocal committed over \$80 million in new capital investments in the last two years on its platforms, "with the potential to spend an additional \$31 million in 1995," Tabler said. "But it may be difficult to commit additional capital to develop these properties due to their short remaining platform lives and marginal profitability."

Presently, platforms in the Inlet are allowed to discharge "produced water" (water brought up from underground reservoirs with oil and gas) as well as drilling cuttings and "mud" (used in drilling fluid, mostly natural compounds). If federal agencies apply "zero discharge" requirements to Cook Inlet, retrofit costs on Unocal's platforms will exceed \$50 million, resulting in the premature closure of the Trading Bay and McArthur River fields. "This would result in lost revenues of over \$500 million, most of which goes to the local community, and approximately 800 lost jobs. The state would lose nearly \$100 million in royalties and taxes," Tabler said.

The U.S. Coast Guard is currently considering a requirement that tankers be escorted by tugs in U.S. waters. If Cook Inlet is not allowed an exemption, this would add \$5 million per year per tug to operating costs, Tabler said. "If we are forced to divert our funds toward escort vessels, most likely the owners will not be Alaskan and that money will flow out of the state."

Cities, resource groups gear up again to push new water quality standards

Dept. of Environmental Conservation has set April 19 as the deadline for the new round of public comments on its revised water quality standards, adopted as regulations Dec. 5, 1994 but appealed by the Sierra Club Legal Defense Fund on Jan. 12, 1995. Municipalities and resource industries (including oil and gas) are gearing up once again to present arguments in favor of the new regulations. Public hearings are set for March 17 in Fairbanks, March 20 in Anchorage, March 22 in Juneau, with a statewide teleconference from teleconference centers in Legislative Information Offices set for March 28. A package of public information materials on the standards will be available in DEC offices Feb. 13.

In addition to the five sections addressed in the SCLDF petition, DEC is proposing a new "anti-degradation" section to be added to bring existing anti-degradation language in state regulations (where it has existed, in various forms, since 1970) into technical conformity with EPA requirements. The actual wording changes are relatively minor, but the section's absence from the package approved by former Lt. Gov. Coghill on Dec. 5 prompted objections from EPA, and could have been an issue raised in litigation, DEC staff sources say. The agency had actually included it in the previous package but deleted it at the last minute at the request of state attorneys, who felt certain changes might not have been properly noticed to the public.

New section added provides for "outstanding national resource waters" classification

What anti-degradation essentially means is that existing quality of water bodies will be maintained unless a "lowering" of water quality (i.e. by allowing discharge of a pollutant) is demonstrated to be necessary to accommodate important economic and social development. However, a new section being added, also needed to comply with EPA requirements, requires protection of existing water quality in "outstanding national resource waters." The new language is verbatim from EPA regulations, but what the section doesn't do is provide how outstanding national resource waters are determined. The section proposed last year provided for the legislature to lay out a system for nomination of outstanding waters for subsequent approval by the legislature, much as state parks or refuges are established. A process to nominate those waters will be set up later, DEC said. Meanwhile, "phase two" of the triennial water quality revisions is on hold until the current review is finished, DEC said. Phase two includes setting a "fish consumption" level to be used in the formula calculating human health risk levels (and therefore, allowable pollutant discharge levels) and specific human health risk criteria for several listed pollutants.

Upcoming events

Feb. 17, 1995: Deadline for submission of recommendations for changes to air quality control regulations. Comments should be submitted to John Stone, DEC, 410 Willoughby Ave. Suite 105, Juneau, Alaska 99801. Phone: (907) 465-5100.

March 29-31, 1995: The Fifteenth Annual Governor's Safety & Health Conference, sponsored by the Alaska Safety Advisory Council, will be held at the Sheraton Anchorage Hotel, Anchorage. Contact: Rebecca Custard, Labor Standards and Safety Division. Phone: (907) 269-4916.

April 19, 1995: Deadline for public comments on Alaska water quality regulations. Fairbanks hearing March 17; Anchorage March 20; Juneau March 22; statewide teleconference March 28. Contact: DEC Water Quality Management Section. Phone: (907) 465-5300.

Senate reconsiders vote on Long Range Financial Planning Commission

As this goes to press, the State Senate is preparing a final vote on HCR-1, a resolution creating a Long Range Financial Planning Commission to make recommendations on solving the impending state fiscal gap. The measure failed in the Senate Feb. 10 when HCR-1 failed to get 11 votes needed for passage. Senators will vote on "reconsideration" Feb. 14.

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State Capitol
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HOUSE BILL NO. 209

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - FIRST SESSION

BY REPRESENTATIVE GREEN

Introduced: 2/27/95

Referred: House Special Committee on Oil and Gas, Resources, Finance

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to the authority of the commissioner of natural resources to
2 allow reductions of royalty on oil and gas leases; and providing for an effective
3 date."

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

5 * Section 1. AS 38.05.180(j) is amended to read:

6 (j) To prolong or enhance the economic life of an oil or [AND] gas field or
7 to reestablish commercial production of shut-in oil or gas that would not otherwise be
8 economically feasible, the commissioner

9 (1) shall adopt regulations that are applicable to all bidding methods
10 to allow reduction of royalty on leases; the regulations that are adopted under this
11 paragraph to prolong or enhance the economic life of an oil or gas field shall be
12 developed to compensate for increasing costs or decreasing value of production;

13 (2) [. THE COMMISSIONER] may not grant a reduction of royalty
14 (A) unless the lessee requesting the reduction makes a clear

1 showing that the revenue from the lessee's share of all oil and gas
2 [HYDROCARBONS] produced from the field is and is likely to continue to be
3 insufficient to produce a reasonable rate of return with respect to the lessee's
4 total investment in the field; and

5 (B) if the royalty reduction is requested to prolong or
6 enhance the economic life of a field, unless at least two years' initial
7 production from the field has occurred;

8 (3) [. THE COMMISSIONER] may condition a royalty reduction
9 granted under this subsection in any way necessary to protect the state's interest,
10 including restoration of the state's royalty share in the event of an increase in the price
11 of oil or gas;

12 (4) [. BEFORE APPROVING A ROYALTY REDUCTION, THE
13 COMMISSIONER] shall, before approving a royalty reduction under this
14 subsection, make a written finding that the state has obtained the maximum possible
15 economic return that is compatible with allowing a reasonable rate of economic return
16 for the lessee, and send copies of the finding to all members of the legislature.

17 * Sec. 2. APPLICABILITY. The provisions of AS 38.05.180(j), amended by sec. 1 of this
18 Act, apply to leases in production on the effective date of this Act.

19 * Sec. 3. This Act takes effect immediately under AS 01.10.070(c).

Senate Resources Committee
Testimony for February 1, 1995

By

J. Kenneth Thompson
President, ARCO Alaska, Inc.

Introduction

Thank you Mr. Chairman and Members of the Senate Resources Committee. For the record, my name is Ken Thompson and I am the President of ARCO Alaska, Inc. I reside in Anchorage, Alaska. I am also president of the Alaska Oil and Gas Association, or "AOGA," for 1995. I am here to testify concerning ARCO's views on ways to (1) improve communication and working relationships between our industry and the government, and (2) suggest ideas that could make new oil and gas investments Alaska more globally competitive.

And I want to share with you my optimism because of significant, recent improvements in our relationship with the state. During 1994, ARCO settled some long standing tax disputes. Better yet, we've reached agreements which will allow us to avoid these big costly disputes in the future. As a result, we have the opportunity for our company and the government to form more of a true "partnership."

At the state level, Governor Knowles has asked what he can do to help us develop new fields and marginal reservoirs in existing fields that are currently uneconomic or not competitive globally. I believe he's sincere. Legislative leaders have also asked these same questions. I believe you're sincere. At the Federal level, it's important to note that the Alaska Congressional delegation now has tremendous power in Washington.

If we work together, it could mean new opportunity for our industry, the state, and for the people of Alaska. If we seize this opportunity, it could mean stabilized revenues and stabilized jobs for the state. It could mean stabilized revenues and stabilized jobs for our industry. We do share common goals.

The Importance of Alaska to ARCO

ARCO has been in Alaska for 40 years, and we're working hard to stay another 40 years. We have a vision in ARCO Alaska, Inc. to be "SAFE, LOW-COST and LONG-TERM." That's our "bumper sticker" for a successful future, and we have strategies to accomplish that future.

Our company is the largest producing company employer in Alaska with over 1,600 employees -- 95% of those employees reside in Alaska.

ARCO is also the state's most active oil and gas explorer. We have quite an exploration legacy in Alaska, having discovered the Swanson River Field, Prudhoe Bay (the largest field in the United States), Kuparuk (the second largest field in the United States), Lisburne, and Point McIntyre (the largest oil discovery in the United States within the last fifteen years).

ARCO sees tremendous future opportunity in Alaska. We will continue to explore. We will continue to invest in new development. In fact, ARCO Alaska's five-year capital plan calls for \$1B of new investment in Alaska ... \$150MM for new exploration and \$850MM for development activities. But we do see potential incremental investments that could be added to our plan if we work together to make these incremental investments more competitive with worldwide investment opportunities.

How to Become Globally Competitive

How do new investment opportunities in Alaska become more globally competitive? Before answering this, let me stress that ARCO is not asking for tax or royalty changes on existing production from currently active reservoirs in Prudhoe Bay, Kuparuk, or Pt. McIntyre because we know the state depends on these revenues. We are asking, however, that there be no new tax increases on this existing production considering that there have already been thirteen tax increases since just prior to Prudhoe Bay startup. To date, ARCO has paid \$10B in royalties and taxes since 1977.

For new investments in marginal or non-economic reservoirs in existing fields, and for small to moderate-sized new field discoveries, ARCO does believe new tax and royalty changes should be considered to make investments competitive.

But before new ideas can be discussed, it is so important to realize that first, our industry and the government must learn to better trust each other and to have more open communication -- like these discussions today. We need a true "partnership" relationship. These key fundamental needs of better trust and communication were listed in the August 1994 report by Gaffney, Cline & Associates entitled, "Perceptions of Alaska: Oil and Gas Market Research Project."

Comments on the Gaffney, Cline & Associates Report

ARCO does not agree with every conclusion or with every recommendation contained in the report. But there is much in the report we do endorse. It

offers the state and the Alaska oil industry some good advice on how to improve the state's competitive position.

ARCO does disagree with a key assertion in the report, and I quote, "that the oil and gas industry in Alaska is in a state of near crisis which, left unattended, has the potential for severe long term damage to both public and private interests in the state."

In my opinion, the Alaska oil and gas industry is not in a state of near crisis.

These are challenging times. But the companies doing business here understand the challenges which confront them and are taking the steps necessary to reduce operating costs and remain competitive.

The question before Alaskans is whether Alaska is going to be a place of diminishing or expanding opportunity. Alaska has tremendous oil and gas potential, potential which can be tapped if the oil industry and the state can find better ways to work together.

I'd like to talk about the most important recommendation in the Gaffney Cline report. It's found in the executive summary and reads like this:

"The single largest step towards improving and optimizing the situation would be an improvement in the communications and working relationships between the industry and the government. Any improvement in this crucial area can lead only to mutual benefit." ARCO agrees.

Industry and government are working together in other parts of the world to attract oil and gas investment. Why can't we do it here?

I'm not here today to criticize or blame the state for the present situation.

Partnerships are two-way streets. Building and maintaining effective partnerships are not easy. They require commitment and constant effort. They require effective communication, and most importantly, they must be built on a foundation of trust and mutual respect.

Alaska and the oil industry have had some spectacular successes. But I think everyone here would agree that our partnership isn't all it could or should be, and that is as much as the industry's fault as it is the state's.

The Alaska Oil and Gas Association has appointed a team representing several companies to identify actions our industry can take to improve our partnership. We want to know what we in industry are doing that is detrimental to our relationship. We want to know what we can do to

improve communication and build trust. We ask for your input on what you think we could do better.

The AOGA team has already identified some actions that industry can take to improve communication and trust:

- We need to discuss historical "baggage" that exists between us, learn to forgive our mistakes, and move forward.
- We in industry must "walk the talk." Too often in the past, companies have "cried wolf" or "the sky is falling," saying the state must accept the change we recommend or else! Instead, let's share information openly, sit down together and innovate options that we all can live with.
- We need to build a new trust relationship with the state to provide a full range of information on new projects needed for more informal decision making.
- At times, we've blamed the state agencies for permit delay when, in fact, we could have improved our timeliness in submitting permit applications earlier and involved agencies up front in the permit preparation stage.
- And, we need to continue communication in improving our industry's image. Too often we're described as "Big Oil" when in fact we're comprised of hard-working individuals who simply want to provide a fair return on investment back to their company but who also want to earn a good, honest living for their families, hopefully long term, and who want to be involved in their communities in helpful ways.

In concluding about improving trust and communication, I know we can better understand each others problems. I know we can identify areas of mutual interest. And I know we can work together to ensure that Alaska is a place of expanding opportunity for our industry and for all Alaskans.

Bring In New Investment Partners

I want you to know that we at ARCO Alaska have been and are continuing to take action to bring new investors, including independent oil and gas companies to the state.

Over the last five years, the only new oil and gas companies to invest in Alaska have done so through partnerships with companies actively exploring here. ARCO Alaska has been the leader in bringing new exploration partners into the state. ARCO was instrumental in bringing Anadarko Petroleum Company into our Colville Project and Total Minatome (a French company)

into our Kuvlum Project. We also increased Union Texas Petroleum's (UTP) investment in Alaska by selling UTP an interest in Kuvlum and increasing its interest in Colville. We have entered into an Area of Mutual Interest Agreement with Anadarko in the Cook Inlet. Anadarko and UTP are large independent oil companies, and their participation has been critical to those projects.

We are currently seeking partners on seven high risk, exploration projects in Alaska. All of these prospects are on state leased lands where the state would receive royalty if we are successful in bringing these projects on production. While we have already generated some interest in these projects, we have found that we must sell interested companies on both the project and on Alaska before they will take a serious look. Representatives from our Exploration and Land Department are soliciting the participation of other oil and gas companies in the prospects during the North American Petroleum Exposition in Houston February 1 and 2. The conference is being attended by hundreds of companies, both large and small.

Our record speaks for itself. ARCO Alaska wants to see an increase in the number of oil and gas companies operating in Alaska, whether those companies are majors or independents and regardless of whether those companies invest in our projects or in projects offered by others, including the state of Alaska. Our reasons for supporting an increase in competition are as follows:

- We have a large land/lease investment in Alaska. An increase in drilling activity will only enhance the value of that investment.
- An increase in the number of companies exploring in Alaska will increase the number of exploration ideas generated in Alaska. As an active explorer in Alaska, we only stand to gain when companies introduce new exploration ideas in Alaska.
- The high costs and the high risks associated with exploration projects in Alaska require ARCO Alaska to seek partners to spread our risk and diversify into as many Alaskan projects as we can.
- As a TAPS owner, ARCO has a vested interest in seeing increased production from the North Slope, no matter who the producer is. TAPS, of course, is a common carrier which is obligated and eager to transport production tendered by any company operating on the North Slope.

Tax and Royalty Changes/Incentives

Now let me turn our attention to another of the Gaffney Cline conclusions which ARCO strongly agrees with, stating, "protection of the state's interests

in the longer term will, we believe, require ... a more fiscally progressive approach to legislation that encourages development, especially of existing discoveries, at lower prices, but claws back revenue from the more profitable projects or after prices rise ..., and, a more aggressive effort to spur increased industry investment in the Alaska petroleum sector."

We at ARCO believe such tax and royalty changes for new investment projects are needed if we are to add incremental investments beyond those in our current five-year plan. We are supporting the efforts of a large industry group to assess new ideas such as net profits concepts or variable royalty rates tied to oil prices and well production rates or field size. When prices are low, when production rates are lower, or when a new field is smaller, state net profits share or royalty should be less, allowing the investor the opportunity to still achieve an acceptable return on their investment. When prices are high, when production rates are higher, or when the field discovery is much larger, then the state should realize an increasing share through higher state net profits share or royalties.

The oil industry's group will finish its tax and royalty work in February. We will bring forward these ideas to the new administration's agencies and the legislature. We wish to participate in an oil and gas tax/royalty conference. Let's sit down at that point and see where we can build trust around options that are "win/win" for the state and the industry.

"Partnering" Concepts

We hope that general tax and royalty changes or incentives are enough for ARCO to consider incremental investment opportunities in Alaska. If they are not, ARCO will be proposing the concept of "project partnering" for specific projects which we see will not move forward without joint innovation between the state and our company.

ARCO supports the "partnering" concept as an approach to conducting business that addresses the economic challenges confronting the state of Alaska in the latter half of the 1990s, and as recently defined in a special report entitled "TEAM ALASKA: PARTNERING FOR ALASKA'S FUTURE." This is a study facilitated recently by Commonwealth North, but involving a large, diverse group of Alaskans, including individuals not members of Commonwealth North. These men and women representing different industries, Native corporations, non-profit organizations, academia, an environmental group, labor, and government believe we can define common goals and new ways to work together to solve old problems in our state.

I've often been asked to define partnering. Partnering is using a mutual gains approach to reach beneficial goals. Partners adopt a win/win style. In win/lose negotiations, by contrast, each side focuses completely on getting the

biggest slice of the pie. Partners, on the other hand, still divide up the pie but they don't let that activity prevent them from working together to bake more pies, or grow a pie bigger, so to speak. Trust and communication are key elements in the partnering process.

The traditional, inflexible, win/lose style just won't work in Alaska if we are to have new incremental investment. Alaska is losing the global competition for oil investment to nations that are offering meaningful partnering opportunities. A good example is the United Kingdom which has attracted back industry and now has growing oil and gas activity in the North Sea, despite major cost disadvantages. After major tax and royalty changes for new fields, there has been over \$40 billion of new investment in the last eight years. Production was on the decline there, like in Alaska, near 1.5 MMBD but now has rebounded to 2.6 MMBD, with 40% (1.1 MMBD) coming from new fields.

Dropping the win/lose style in Alaska will be resisted by those who feel threatened by change. But through open, frank communication we can address those fears and overcome many obstacles to development here in Alaska. It is essential to dedicate ourselves to thinking in a win/win way.

Specific "Partnering" Projects

If general tax and royalty changes or new incentives are not enough to move forward on some potential projects, how would "project partnering" move forward? I visualize three important activities. First, I cannot overemphasize the importance of the state continuing the process of developing a viable fiscal plan for a "safe landing." If the state has such a plan and sticks to it, it would significantly reduce the uncertainty that we feel about the value of long-term investment in Alaska. This will provide a crucial backdrop to any specific "partnering" projects. Let me hasten to add that I recognize the strides being made now in this area by the legislature and administration.

Second, as we proceed on this first front, we can begin to develop a detailed understanding about what Alaska's competition is doing to attract investment. ARCO has already examined the oil tax and royalty regimes in over 70 countries. We have particularly studied those countries where changes in policy resulted in new exploration and development activity such as the United Kingdom, Alberta-Canada, and Australia. We look forward to sharing these studies with you or conducting new studies, including perhaps a visit to Alberta, Canada to confer with leaders there.

Third, let's look for a moment at the specifics of demonstration projects. The idea here is very simple. We can find projects that would not otherwise go and work with the state to make them reality. By projects, I mean any

uneconomic project. It does not have to be part of ARCO's portfolio. I want you to know that on non-ARCO projects, we stand just as ready to help. We want the process to work. We hope that we will eventually get a chance to advance an ARCO project. As I mentioned earlier, typical projects will be: (1) exploring for small or medium sized accumulations; (2) bringing on known, but uneconomic fields and uneconomic horizons in existing fields; or (3) extending the life of a marginal field.

To make projects a reality, the industry and state would work together to ensure that Alaskan workers and Alaskan fabrication are cost-competitive and are used; that the capital commitment is made and that the state shares the profit. We must also ensure appropriate steps are taken to protect the environment; we must not lessen our environmental standards.

Finally, let me turn to specific demonstration projects that ARCO might advance. Over the past few months, I have had ARCO staff evaluating and sifting through project possibilities. This process has not been completed, but some possibilities exist. We are looking very seriously at the Kuparuk field West Sak accumulation where there are several billion barrels of oil-in-place, but only a fraction can be physically recovered. There are significant research and technology challenges in understanding West Sak recovery and production. A technical team has been reconstituted to look at what would be required to produce West Sak oil commercially.

In addition, we have identified some possible exploration plays, which I may be able to elaborate on in the near future.

Interestingly, one trend that has become very apparent in our analysis of marginal oil field projects is that restructuring royalty or reasonable net profits concepts can be very leveraging to some projects.

Closing ... Better "Partnership"

We at ARCO will continue to assess possible "partnering projects." But we actually hope and prefer that general tax and royalty structure for new investment opportunities can be tailored to oil prices, production rates, and field size to allow many new opportunities to move ahead on their own -- without "partnering" a specific project. But, we will stand ready to suggest "partnering projects" if general changes alone aren't enough.

One thing we can do in the meantime is to better foster "partnership" relationships.

As an Alaskan business that has been in Alaska for 40 years and as one of the state's largest tax and royalty payers, we at ARCO are encouraged by what we heard from Governor Knowles about budget discipline and controlling state

spending. We are encouraged that the members of the Legislature are willing to work together to shrink the fiscal gap.

As a company with a huge stake in Alaska, in TAPS, in existing fields and in potential resources that can't be developed in today's economic climate, we are encouraged by the legislature's and administration's willingness to consider changes in the state's tax and royalty regime for new projects -- which could spur on a new round of Alaska exploration and development of marginal fields.

In my opinion, the time is right for our industry to build our partnership with the state into something better and more positive than ever before. But we must go beyond just the words of "partnership."

As part of this "partnership," ARCO has already moved beyond just words and is taking specific actions. We made our top corporate executives in Los Angeles available to Governor Knowles and his economic development team for both fact finding and discussion of initiatives. We will make our top executives available to leaders from the Alaska Senate and House if you have an interest, or our local management can brief you in more detail on ARCO Alaska activities if that is your preference. In the meantime, we believe our "partnership" is happening today, and it will continue. Let me summarize in closing that -- in the spirit of "partnership":

- 1) ARCO Alaska has agreed to participate in a tax and royalty conference to discuss both tax laws and royalty changes for oil and gas exploration and development when the Governor and Legislature convene one.
- 2) ARCO Alaska will continue to assist the Congressional Delegation, the Knowles Administration, and the Alaska State Legislature in their efforts to open ANWR to environmentally responsible oil and gas exploration and development.
- 3) ARCO has changed its long-standing neutral position on the North Slope export ban, and will now support lifting the ban.
- 4) ARCO has agreed to keep the public and the state informed of our efforts to assess one of the largest potential resources ARCO has in Alaska: North Slope natural gas.
- 5) ARCO has reformed our West Sak team, looking for ways to make that huge oil resource economically viable.
- 6) ARCO informed Governor Knowles' Administration and the press about the North American Petroleum Exposition in Houston, and ARCO's efforts to attract new exploration partners. A representative

from the administration is attending to help encourage other companies to consider investment in Alaska.

- 7) We will conduct all operations in an environmentally responsible manner.

In closing, let me state that ARCO will continue its long-standing commitment to Alaska and will do its best to help create an even better win/win "partnership" with the state... a "partnership" where we share common goals of sustained economic development, more stabilized revenues and jobs -- all of this while maintaining high environmental standards.

Thank you. Mr. Chairman, I would be happy to answer any questions that the committee may have.

Testimony of James F. Branch
On the Business and Investment Climate in Alaska
Before the Senate Resources Committee
February 1, 1995

Mr. Chairman, members of the Committee, my name is Jim Branch. I am the Production Manager with responsibility for Exxon's interests here in Alaska. I want to thank the Committee for allowing me the opportunity to testify before you today.

Before discussing some principles that could be used to evaluate specific incentive proposals to facilitate the development and production of oil and gas, I want to share our views on the most important initiatives that will have the greatest positive impact on investor perception and confidence in our state.

The findings of the recent Gaffney-Cline report on the current climate for the oil and gas industry in Alaska are very similar to Exxon's own business experiences. Rather than review the issues raised in that study, however, I would like to highlight the three things we think the state can address to improve the situation, which are: fiscal reform; tax and regulatory stability and clarity; and improved communication and cooperation between the state and industry. These offer the most opportunity for positive impact on the business climate and should be acted upon prior to discussions on specific incentives. If an investor concludes from past experience that any incentive granted at the outset will be taken away over time, it would influence his decision, and the investor may decide it is unwise to invest in a marginal project.

First, the most important message the state can send to any potential investor is that the budgetary problems which have plagued the state in the past are being corrected. Exxon believes that fiscal reform, primarily through the reevaluation of spending priorities and ultimate spending reductions, should be the state's top concern. Current forecasts indicate a budget deficit of approximately \$500 million. As Governor Knowles stated in his State of the Budget Address, if the state does not stop spending more than it is taking in, that budget gap will grow dramatically and will eventually lead to the depletion of our reserve accounts. With such a budgetary problem, potential investors will likely be unwilling to spend major investment dollars until Alaska demonstrates it is willing to address this issue.

Second, the state should improve the administration of its tax regulations to provide clarity, predictability, and reasonable balance in the interests of both the state and the taxpayer. The potential for frequent and unanticipated changes of tax laws and regulations or, equally important, de facto increases in taxes by the inconsistent application of tax laws and regulations, impose an unnecessary risk that only reduces the likelihood of a prospect getting the go ahead. An investor needs to be able to reasonably determine what taxes will likely be owed over a project's lifetime at the time the original investment is made and remain confident that those expectations will be maintained. Likewise, an investor needs to be reasonably sure that the regulatory constraints and operating conditions imposed on an investment will be sustained, so there is a fair opportunity for the projected returns to be realized.

Third, better communication and cooperation needs to be established between the state and industry to avoid disputes which are debated through costly litigation and to seek alternative processes to resolve differences.

Although Exxon feels that fiscal reform and an improved business climate will have the greatest positive impact on investor perception of our state, well-designed exploration and production incentives have a role in enhancing the specific project. While Exxon is not proposing any specific incentives at this time, I can share our thoughts on their design, so that any proposed incentive sends a positive signal to the entire investment community.

Any proposed incentive should operate to increase the state's overall revenues from production, and not just subsidize one field or project at the expense of another. The incentive should be designed to generate incremental new developments or additional production from existing fields through increased recovery or prevention of premature abandonment. The incentive should not be too limited or too focused, but should have general applicability to all members of industry on a consistent basis. The "win/win" concept is not truly achieved if the state or any member of our industry is advantaged at the expense of another. The state and all of industry wins when a well designed incentive "makes the pie bigger" without penalizing someone else in the process.

For any investor to take a proposed incentive seriously, the incentive must come without fear of a hidden price tag. An incentive offered today that industry is forced to pay for tomorrow through increased taxes is not incentive to invest in our state.

We recognize that our business is one that involves risks and we are prepared to deal with what I call the traditional risks. For example, will the recovery of oil live up to our production expectations? More difficult to manage are risks created by the state. This is especially true where the demands for more revenue can only be met by greater taxes from the industry that already provides approximately 85% of the state's funding.

Incentives alone will not improve the state's business or investment climate. Exxon believes that in order for Alaska to create a climate that will attract capital for future development, efforts must be made to improve current business conditions. A more favorable business and investment climate must include fiscal responsibility, tax and regulatory stability, better communication and cooperation between industry and the state and, potentially, incentives.

Mr. Chairman, Exxon is pleased that this committee and the Governor are interested in improving the current business climate for the oil and gas industry, and we stand ready to work with you, the legislature, the Governor and his Administration in achieving these goals. Thank you again for allowing me this time to address your Committee. I would be happy to answer any questions you or any member of your Committee may have.

L. RALPH DARTEZ FEB. 1, 1995
SENATE RESOURCES HEARING

(H:\wp\95fa01\11.nlc/1/31/95)

GOOD AFTERNOON -

MY NAME IS RALPH DARTEZ AND I AM THE ALASKA REGION
MANAGER FOR MARATHON OIL COMPANY. I APPRECIATE THE
OPPORTUNITY TO SHARE WITH YOU A LITTLE ABOUT MARATHON'S
BUSINESS IN ALASKA AND SOME OF THE ISSUES THAT WILL
IMPACT OUR LONG-TERM FUTURE.

MARATHON'S ALASKA OPERATIONS ARE LIMITED TO THE COOK
INLET/KENAI PENINSULA AREAS. OUR NET OIL PRODUCTION
AVERAGES 10,000 BOPD AND WE SELL ABOUT 130 MMCFD OF
GAS OR APPROXIMATELY 30% OF THE GAS SOLD IN
ALASKA.

EFFECTIVE DECEMBER 1, 1994, MARATHON AND UNOCAL
COMPLETED A PROPERTY EXCHANGE FOR KENAI PENINSULA
ONSHORE PROPERTIES TO CONSOLIDATE OWNERSHIP IN AN

EFFORT TO RATIONALIZE OVERHEAD COSTS AND IMPROVE EFFICIENCIES. FURTHERMORE, AT THE SAME TIME, CHANGES WERE ALSO MADE IN OUR OFFSHORE COOK INLET OPERATIONS WHEREBY OPERATORSHIP OF THE OFFSHORE FACILITIES WAS CONSOLIDATED UNDER ONE OPERATOR, UNOCAL. BY CONSOLIDATING OFFSHORE OPERATIONS UNDER A SINGLE OPERATOR, WE WERE ABLE TO REDUCE OVERHEAD COSTS SIGNIFICANTLY AND ELIMINATE DUPLICATION OF INFRASTRUCTURES NECESSARY TO SUPPORT OFFSHORE OPERATIONS. THE CHANGES MADE IN OUR OPERATIONS WILL IMPROVE THE VIABILITY OF BOTH COMPANIES AND MORE IMPORTANTLY TO THE STATE, WILL RESULT IN EXTENDED FIELD LIFE.

THE CHANGES JUST DESCRIBED DO NOT MEAN MARATHON'S COMMITMENT TO ALASKA IS DIMINISHED IN ANY WAY. OUR LONG TERM INTERESTS ARE FOCUSED ON THE AREAS NEAR OUR CURRENT INFRASTRUCTURE IN THE COOK INLET/KENAI PENINSULA AREAS.

AS YOU ARE ALL AWARE, THE COOK INLET IS A MATURE, EXTENSIVELY EXPLORED PROVINCE. TO DATE 248 EXPLORATORY WELLS HAVE BEEN DRILLED AND THESE COVER ALL THE KNOWN LARGE GEOLOGIC STRUCTURES IN THE AREA. THERE ARE NO LONGER EXPECTATIONS OF FINDING LARGE, PROLIFIC OIL OR GAS FIELDS. INSTEAD, OUR REASONABLE EXPECTATIONS FOR THIS PROVINCE ARE FIELD EXTENSIONS TO EXISTING FIELDS AND OR SMALL TO MODERATE SIZE EXPLORATION PROSPECTS. *FIELD EXTENSIONS ARE DEFINED AS PREVIOUSLY MISSED OR UNTESTED OPPORTUNITIES WITHIN OR IMMEDIATELY ADJACENT TO EXISTING PRODUCING PROPERTIES.*

FIELD EXTENSIONS, WHICH ARE TYPICALLY RELATIVELY LOW RISK, ARE BEING CONSIDERED AS THESE MATURE FIELDS DEplete, PARTICULARLY SINCE OPERATING COSTS AND REGULATORY PRESSURES ARE INCREASING. AS EXEMPLIFIED IN OUR EXCHANGE WITH UNOCAL, OUR INDUSTRY IS CONTINUALLY STRIVING TO CONTROL COSTS, AND HAS MET WITH SOME SUCCESS; BUT THE REALITY IS, THERE WILL BE A CONTINUAL, UPWARD

PRESSURE ON COSTS. REMAINING INVESTMENT OPPORTUNITIES IN THESE MATURE FIELDS ARE VERY SENSITIVE TO PRODUCT PRICE AND FIELD LIFE. THIS WAS EVIDENT IN EARLY 1994 WHEN OIL PRICES WERE LOW, ALMOST ALL COMPANIES SIGNIFICANTLY CURTAILED THEIR DRILLING INVESTMENTS.

EFFORTS BY THE STATE TO IDENTIFY INCENTIVES OR STEPS TO FOSTER INVESTMENT ARE APPRECIATED. WE ARE WORKING WITH THE OTHER INLET AREA PRODUCERS TO DEVELOP A BROAD CONSENSUS APPROACH TO IDENTIFY INITIATIVES THAT MIGHT PROMOTE DEVELOPMENT IN COOK INLET/KENAI PENINSULA. UNTIL SPECIFIC CONCLUSIONS HAVE BEEN FORMULATED, THE COMMENTS I OFFER TODAY ARE GENERAL IN NATURE. PLEASE BE ASSURED WE WILL DISSEMINATE OUR DETAIL THOUGHTS WHEN OUR REVIEW IS FINALIZED.

ANY ACTIONS WHICH LIMIT OR REDUCE ECONOMIC RISK AND/OR UNCERTAINTY WILL INEVITABLY ENCOURAGE INVESTMENT. FIELD AND FACILITY ABANDONMENT IS AN AREA OF UNCERTAINTY FOR

OUR INDUSTRY TODAY. IT IS IMPERATIVE THAT THE AOGCC AND DNR CONTINUE THEIR PROCESS OF DEFINING THESE OBLIGATIONS TO HELP COMPANIES UNDERSTAND THE POTENTIAL IMPACTS TO FIELD ECONOMICS AND FUTURE OPPORTUNITIES.

THE DEPARTMENT OF REVENUE HAS MADE SOME PROGRESS IN WORKING WITH THE INDUSTRY TO DEFINE TAXABLE VALUE FOR PRODUCTION TAX PURPOSES. IN ADDITION TO FURTHER PROGRESS IN THIS AREA, WE BELIEVE THE DEVELOPMENT OF AN INDEPENDENT APPEALS PROCESS FOR TAX DISPUTES COULD ULTIMATELY PROVIDE A MEANS FOR REDUCING UNCERTAINTY FOR THE TAXPAYER.

TITLE 38 ALREADY DELEGATES SOME AUTHORITY TO THE DEPARTMENT OF NATURAL RESOURCES TO CONSIDER ROYALTY REDUCTIONS FOR FIELDS WHERE WEAK ECONOMICS THREATEN THE FUTURE LIFE OF THE FIELD. WE WOULD LIKE TO ENCOURAGE THE STATE TO REVIEW THE STATUTE AND HOW IT HAS BEEN ADMINISTERED HISTORICALLY. WE WOULD FURTHER SUGGEST

THAT FUTURE REQUESTS FOR ROYALTY REDUCTION BE VIEWED MORE OPENLY AND AGGRESSIVELY, PARTICULARLY FOR LOW PRODUCT PRICE REGIMES. WE ARE INTENTLY WATCHING HOW BP'S REQUEST FOR BADAMI IS BEING HANDLED.

REGULATORY PRESSURE CONTINUES TO BE THE MAJOR THREAT TO MATURE FIELDS. IT IS IMPERATIVE THAT THE STATE CAREFULLY CONSIDER INDUSTRY INPUT TO MANDATED STATUTES AND RESULTING REGULATIONS TO ENSURE THE ADOPTION OF THOUGHTFUL REGULATIONS THAT ADD VALUE.

Water Quality
the need for
regulations
FOR MARATHON, EXPLORATION OPPORTUNITIES WILL HAVE TO BE ABLE TO CAPITALIZE ON EXISTING OIL AND GAS INFRASTRUCTURES. WE VIEW THE POTENTIAL OPPORTUNITIES AS SMALL TO MODERATE IN SIZE. ECONOMICS OF FUTURE DISCOVERIES/PROJECTS ARE LIKELY TO BE DEPENDENT ON THE AVAILABILITY OF EXISTING INFRASTRUCTURE; THEREFORE, IT IS CRITICAL THAT NEW DISCOVERIES BE MADE SOON, BEFORE THE EXISTING INFRASTRUCTURE SURPASSES ITS ECONOMIC LIFE.

TO FOSTER EXPLORATORY INVESTMENT IN THE COOK INLET/KENAI PENINSULA AREA, LAND ACCESS IS OUR NUMBER ONE CONCERN. WE APPRECIATE THE EFFORTS OF THE LEGISLATURE LAST YEAR IN PASSING SENATE BILL 308 WHICH PROVIDES MORE CERTAINTY TO THE LEASE SALE PROCESS.

IN REVIEW, THE FOLLOWING SUMMARIZES OUR AREAS OF INTEREST:

- FIRST OF ALL, LET ME AGAIN STRESS THAT WE SHOULD CONTINUE TO WORK WITH THE OTHER COOK INLET AREA PRODUCERS IN DEFINING AND DEVELOPING A BROAD CONSENSUS APPROACH FOR INITIATIVES TO PROPOSE IN DETAIL THAT EITHER STIMULATE GROWTH OR AT LEAST SUSTAIN WHAT WE HAVE.
- DEVELOPMENT OF AN INDEPENDENT APPEAL PROCESS FOR TAX DISPUTES WILL REMOVE SOME ECONOMIC UNCERTAINTY.

- TAX CREDITS AND ROYALTY SUSPENSIONS COULD BE MORE LIBERALLY APPLIED FOR MARGINAL FIELDS OR TO STIMULATE MARGINAL NEW FIELD INVESTMENTS.
- PRESERVE THE CERTAINTY PROVIDED VIA SB 308 TO ENSURE TIMELY, DEPENDABLE ACCESS TO LANDS.
-  • ENSURE STATUTES AND REGULATIONS CAREFULLY CONSIDER THE IMPACT TO INDUSTRY AND ADD VALUE.

IN CONCLUSION, ALASKA IS AN IMPORTANT PART OF MARATHON'S DOMESTIC OPERATIONS AND WE ARE STRIVING TO EXPAND AND MAINTAIN OUR RESERVE BASE HERE. FINALLY, WE BELIEVE IT IS VERY IMPORTANT FOR THE TWO BODIES OF THE LEGISLATURE TO PARTNER WITH THE ADMINISTRATION TO SCOPE A FRAMEWORK FOR ACCEPTABLE INITIATIVES.

THANK YOU.

Testimony of

James A. Palmer
Director, External Affairs

BP Exploration (Alaska) Inc.

to the

Senate Resources Committee

Juneau, Alaska
February 1, 1995

Good afternoon. My name is James A. Palmer, and I am director of external affairs for BP Exploration (Alaska) Inc. John Morgan, BP's president, wished to testify himself but is out of the state on business.

Given our common challenges and shared opportunities as an industry and as a state, it's particularly fitting that we're gathered here together today to explore how we can work together to attract new industry investment to Alaska. BP is pleased to be part of this new dialogue, which we hope will lead to a new era of cooperation between state government and the state's largest investors and taxpayers.

Our industry has gone through an extended period of unprecedented change -- often painful -- to arrive at our current crossroads. We've experienced downsizing, rightsizing, restructuring, realignment, outsourcing, alliancing, shared services, streamlining, technological breakthroughs and countless other innovations in the way we do business in order to remain competitive in the global market.

As a result, we've been able to reduce costs in a climate of declining production, we've been able to hold overall production decline on the North Slope to less than 5% per year. We have been able to hold decline to these levels only by continuing to invest in new and existing fields on the North Slope. This year we expect to invest more than a half a billion dollars of capital in Alaska, successfully competing within BP for those funds.

These investments generate jobs for Alaskans and revenues for Alaskan businesses. They help to sustain the flow of revenues that fund state government spending and fuel future investments in the Alaskan oil industry. They extend the lives of our North Slope operations, and they hold one of the keys to Alaska's economic future.

Despite our best efforts within the industry, however, we remain under siege from a variety of forces undermining our efforts to attract additional investments to Alaska. In real terms, the price of oil has been on a downward trend for the past 15 years. This, combined with declining production in Alaska, has slowed the flow of revenues that fund future investments.

At the same time, a world of new investment opportunities -- literally as well as figuratively -- has been opening up to the oil industry due to falling political barriers, new technologies and friendlier relationships with many host governments in oil provinces around the world. In this global environment, companies are limiting the scope of their activities and becoming increasingly selective in choosing which project to pursue. Investments are directed to areas offering the highest returns with the lowest risks.

"5B" A big victory
capital for us

Alaska is disadvantaged in this fiercely competitive environment for increasingly scarce investment capital due to our remoteness, our declining production, our high transportation costs, our restricted markets, a state budget deficit that casts a cloud of uncertainty over all of our investments and a history of antagonism between industry and the state. Furthermore, the opportunities that do exist on the North Slope consist of marginal new oil fields or marginal projects within existing fields.

We believe the first step toward capturing the significant potential for new investments, revenues and jobs in Alaska in this emerging era of marginal development on the North Slope is to redefine "us and them." Us meaning Alaska's industry and government working together to compete globally for investment capital. It's imperative that we work together to take tangible steps today toward a strong and stable industry, toward a strong and stable Alaskan economy, tomorrow.

We're encouraged that the legislature is taking initiatives such as your hearing today to provide forums for the dialogue that will enable us to work together to develop win-win solutions to our common challenges. We're also encouraged that the governor has made unity between government and business a theme of his new administration and has reinforced his words with his actions since he took office.

The progress we've made in the past year working cooperatively to lift the federal ban on North Slope oil exports is testimony to what we can accomplish working together. Ending the ban will truly be a win-win outcome that will both enhance the flow of revenues to producers and the state and enhance the competitiveness of Alaskan investments.

Resolution of significant past tax disputes during 1994 have improved the investment climate in Alaska. We can now focus our efforts on the future without looking over our shoulders at liabilities of the past.

Recently enacted tax regulations have helped to clarify how to value oil for tax purposes for companies that refine their own oil. However, the same vagueness that led to past disputes continues for companies like BP that sell or trade the oil they produce on the North Slope. Vagueness equals uncertainty, uncertainty equals risk, and risk equals competitive disadvantage in our efforts to attract capital to Alaska.

Tax clarity for all producers would reduce our risk at no expense to the state. It would be a significant win for us and a significant win for the state. By helping to minimize our risk, you can strengthen our position to compete for investments that will benefit us all.

Additional measures may be necessary in order to compete successfully for capital to develop marginal projects. As you may have read, we are proposing a "sliding-scale royalty" for the Badami discovery east of Prudhoe Bay. Our proposal has been variously described as a royalty "reduction" and a "dispute" between us and the state. It is neither.

It is a good faith attempt on our part to find a mechanism for sharing risks and rewards with you, the state, our partner in development, by linking royalty rates with the price of oil. We were asked by the Department of Natural Resources to include the royalty proposal in our application for Badami unitization in order to stimulate discussion. When we complied, we considered our proposal just that: a basis for discussion ... not an inflexible demand, and certainly not the first volley in a protracted dispute.

If we're to work together to successfully attract investments to Alaska, we must all be flexible in approaching the challenges and opportunities posed by each new project. We believe this suggests a broader discussion in the legislative arena of the use of royalties as a development incentive tool. ✓

We're not suggesting that flexible royalty terms are necessary -- or even appropriate -- for every project. But to the extent that they can be used to enhance the competitiveness of projects whose funding otherwise might go elsewhere, it's important that the state have the tool available and ready for use.

Whether to grant flexible royalty terms -- and what kind -- will be a judgment call on the state's part. It will be incumbent on companies like BP that are seeking them, therefore, to be completely open and forthcoming with the information state regulators need in order to make that determination. Only then can we deal with each other in an honest and collaborative manner and work together toward our common objective of securing new investments.

not started
This is not the time for demands. It's not the time for threats or hollow promises, and it's not the time for brinksmanship or posturing. It is the time, if we're truly committed to working together to capture Alaska's share of industry investments, for constructive, open, productive dialogue such as we're having today that leads to win-win solutions for the industry, for state government and for all Alaskans.

I pledge BP's complete, unconditional cooperation and support in this endeavor. Thank you.

Lesson - ? - "under the curve" = "over time" - [No]
→ HL \$ - depends on circumstances

Severance taxes

Ownership = royalties (Halford believes that the severance in such should be modified rather than the ownership such)

operating costs subtracted
from the wellhead price.

EP is \$800 million to bring Badami on line.

OIL ... ALASKA'S FUTURE?

Finding Our Way from 'Here' to 'There'

John C. Morgan, President
BP Exploration (Alaska) Inc.

to the

Alaska Support Industry Alliance
Meet Alaska conference

January 21, 1995

There's a story of an old New England farmer who was sitting in the rocking chair on his front porch when a family of tourists pulled up and asked for directions.

"Excuse me, sir," said the man driving the car, "but could you tell me how to get to Bangor?"

The farmer paused, puffed on his corn cob pipe.

"Well, you go down this way a piece and turn left. Then you go a few miles until you come to a red barn, and then ... no, you don't want to go that way."

Another pause. Another puff.

"No, you want to turn around here, go back the way you came and watch for the ... no, no, that won't work either."

Another puff on the corn cob pipe. A longer pause. Another puff. Then he shook his head.

"You know," he said, "I don't think you can get there from here."

How many times in the past has it seemed like there was no way for Alaskans to get where they wanted to be from where they were?

- Statehood for a sparsely populated territory separated from the rest of the U.S. by another country and nearly half a continent? You can't get there from here.
- Rebuild from the strongest earthquake that ever shook North America? You can't get there from here.
- Engineer and construct an 800-mile pipeline from Prudhoe Bay to Prince William Sound over some of the most rugged and environmentally diverse terrain in the world in order to tap the largest oil discovery in American history? Revive the Alaskan salmon industry after the botulism scare of the early '80s? Survive the collapse in oil prices several years later? Extend the Alaskan visitor industry into the fall and spring seasons, and even begin to transform the state into a viable winter visitor destination?

You can't get there from here. But time after time, by setting aside differences and working together to achieve common goals, Alaskans have found a way.

We face the same predicament today as we confront our future as a state and as an industry. The dilemma is embodied in today's conference theme, "Oil: Alaska's Past ... Alaska's future?" There's no shortage of reasons to be skeptical:

- Competition for the limited investment capital is relentless, and many of our global competitors have an advantage because of our remoteness, declining production, high transportation costs and restricted markets.

- The threat of the state budget deficit looms over all of us, casting a cloud of uncertainty over the viability of our investments. The state's history of litigation and antagonism toward the oil industry, coupled with a volatile price environment, injects another element of uncertainty.

- And increasingly, the opportunities that *do* exist consist of marginal new fields or marginal projects in existing fields.

Oil? Alaska's future? Most certainly we can't get there from here ...

... unless you consider the growing evidence to the contrary. I'm more optimistic today than ever before that by working together again, Alaskans will find a way. You should be as well. Not just because we've overcome seemingly insurmountable obstacles in the past to get where we are today, but also because of tangible strides we've made just in the past year:

- We've repositioned our business in BP -- at least in the short term -- to survive in a world of \$14 oil ... though we're not actively seeking an opportunity to prove it again so soon.

- The framework for our "alliance" relationships with key contractors and vendors is largely in place.

- Our industry has proven we can reduce operating costs in a climate of declining production, and we've held the overall North Slope decline to an average of less than 5% a year through hard work, innovation and massive investment.

- Within BP, we've successfully competed for more than \$500 million in capital funding for Alaskan projects in 1995 ... that's half a billion dollars invested in Alaska this year alone. This is a tremendous achievement, and it's a tribute to the efforts of our staff, our contractors, our suppliers and our industry partners. It's also a place I wouldn't have believed we'd be just 12 months ago when I first addressed this group.

- We brought Niakuk on line, proving that we can successfully develop small, challenging accumulations on the North Slope.

- Thanks in part to the efforts of many of you in helping to defeat Senate Bill 377 last spring, thereby creating a climate conducive to negotiation, we now have our major past tax disputes with the state behind us and can focus all of our efforts on the future. As a result, the new legislature has \$1.7 billion in newfound reserves from settlements with BP and ARCO to help fund a long-term solution to Alaska's fiscal problems.

- We have new tax regulations that will help to avert such disputes in the future for producers that refine their own oil, though the same uncertainties continue for companies like BP that sell or trade their oil. The new regulations also enhance the economics of facility sharing on the North Slope and provide flexibility in the use of natural gas for enhanced oil recovery.

- We have a new governor who has made "unity" a key theme of his administration ... a new governor who has expressed his determination to work with us to make Alaska more competitive for oil industry investment and with the Legislature to forge a long-term state fiscal plan ... a governor whose actions since he took office have reinforced his words.

It's been particularly encouraging to see Governor Knowles visiting with the state's largest investors, as evidenced by his recent trips to Los Angeles and Houston. We at BP are looking forward to his trip to the U.K. in early March to meet with our senior management and government officials, and to see first-hand some of the solutions we've found to overcome the challenges posed by the maturing of the North Sea oil province.

- Our Alaska delegation in Washington has new clout in influencing federal policy, and Energy Secretary Hazel O'Leary has made lifting the ban on exporting North Slope crude oil a top priority. Only a year ago, removing the export restriction appeared to be another place we most certainly couldn't get from here.

- Finally, we have a very real inventory of exploration and development prospects to pursue if we can successfully compete for investments that will enable us to transform potential into projects.

Even when you factor in BP Exploration's successes in places like Colombia, the deepwater Gulf of Mexico, west of Shetlands and the North Sea over the past few years, we now project that Alaska will still account for roughly 30% of the company's worldwide oil production in the year 2002.

Let me repeat that: We now expect Alaska to provide nearly a third of our worldwide oil production after the turn of the century, even with our successes elsewhere. The proportion could be even bigger if we're able to capitalize on additional opportunities we know exist.

I'd like to discuss just two of our prospects with you today -- Milne Point and the Badami discovery. While each poses its own unique technical and commercial challenges, the key ingredients for success are largely the same ... just as they are for other projects and investments that will get us from here to there in our efforts to make oil part of Alaska's long-term future.

For nearly a decade, Milne Point teetered on the brink of shutdown. As many of you will recall, the field actually did cease production for more than two years in the wake of the mid-'80s oil price collapse.

When BP acquired Conoco's and Chevron's interests in Milne Point and became field operator a year ago, the question in most informed Alaskans' minds wasn't so much whether the field would ever expand as whether it would be able to continue to operate.

Why did we make the acquisition? Quite simply, we saw opportunities that Conoco and Chevron didn't, and we had the critical mass with our infrastructure in place in Alaska to make those opportunities worth pursuing.

Our decision was reinforced by our Cascade discovery just southeast of Milne and successful appraisal drilling in the Northwest Milne area last winter.

Developing those reserves, however, requires significant investment capital ... capital for which Milne competes with projects worldwide. In addition to competitive baggage it carries along with other North Slope fields, Milne faces its own unique competitive challenges.

It's the only North Slope field relying on subsurface pumps to enhance flow. The average Milne well still produces less than 500 barrels of oil a day, compared to more than 750 at Kuparuk and more than 1,000 at Prudhoe Bay. And some Milne leases also carry a 20 percent royalty burden, compared to 12-1/2 percent on most other North Slope leases.

Nonetheless, we've been able to make additional investments in Milne competitive by reducing capital costs and minimizing payback time. We've begun a \$120 million, three-year development program involving expansion and enhancement of processing facilities and drilling 29 new wells. Along with other planned drilling, this has enabled us to more than double our projection of Milne reserves.

In the past year, we've increased production from less than 20,000 barrels a day to nearly 25,000 barrels a day. By 1996, Milne should average at least 50,000 barrels a day.

These are wins for us and our contractors. They're wins for all Alaskans: additional revenues, additional jobs, additional throughput that will help to extend the productive life of the Trans Alaska Pipeline.

But these investments are only the beginning of the potential we see at Milne Point. And the technical, commercial and competitive challenges we've overcome to get where we are today are only the beginning of the obstacles we face if we hope to expand Milne even further.

The Schrader Bluff accumulation in the Milne Point field -- the eastern extension of the huge, shallow West Sak accumulation -- is at a depth of 4,000 feet -- compared to 7,000 at Kuparuk and 9,000 at Prudhoe Bay. The estimated 2 billion barrels of oil in place are heavy and viscous, making Schrader oil more difficult and costly to produce.

And unlike Prudhoe Bay and the other producing fields on the North Slope, where the reservoir consists of tight sandstones, Schrader is composed of loose sands that crumble when oil is produced. These sands damage production equipment, so we've had to develop technology to prevent them from entering the wellbore.

Our 1995 drilling plans include six Schrader Bluff wells from existing Milne Point pads. We'll use these wells to test new ways to increase the productivity and reduce costs of Schrader Bluff wells.

Other companies already have spent a quarter of a billion dollars trying to commercialize the shallow sands at West Sak and Schrader Bluff and have only a few million barrels of oil to show for it. So there *is* a significant risk.

We believe 200-400 million barrels of oil in the Schrader shallow sands are currently technically recoverable ... but not commercially. With the right solutions, however, we think we can double Milne's reserves and production again by the end of the century. This could also pave the way toward tapping vast new reserves in heavy oil accumulations at Kuparuk and Prudhoe Bay.

The prize at Badami may be modest compared to Milne's, but the discovery nonetheless could be a watershed in reducing the risks associated with accessing and developing smaller reserve pools across the whole of the North Slope.

With only one appraisal well drilled to date, questions remain about the size and quality of the reservoir. We're drilling two additional appraisal wells this winter and hope to have the results assessed by fall. Badami needs to hold at least 100 million barrels of recoverable oil in order to have a chance to make it commercially viable.

Traditionally, we'd be waiting for the results of those wells before selecting contractors and proceeding with development plans and permitting. But if we follow traditional paths to get from "here" to "there" with Badami, we risk not getting there at all.

Timing is crucial if we're to successfully capture the development opportunities in Alaska's future. It's imperative that we shorten the period between discovery and production -- the period when capital flows in only one direction, and that direction is out.

The approach we're taking with Badami could shorten that period by at least three years and enable us to begin production as early as 1997.

We began evaluating development options many months ago: facility sharing or stand-alone facilities? Onshore or offshore well pad? Elevated or buried pipeline? On-site staffing or remote operations?

Pending results of appraisal drilling, we're now looking at developing Badami from a single onshore well pad with stand-alone processing facilities. A small crew would man and operate the field. We plan a 30-mile buried and chilled pipeline to transport Badami oil to the Endicott oil sales pipeline, and no road. These measures will help to reduce capital and operating costs. We're now ready to move on to the next phase of engineering.

We've already developed an ongoing dialogue with state, federal and borough regulators in order to enhance their understanding of what we're trying to achieve and to incorporate their input and expertise into the planning process, rather than waiting until submitting permit applications this month.

This cooperative and collaborative approach has been valuable, and feedback from almost everyone involved has been extremely positive. We're hopeful it will resolve official and public concerns about the project and help to expedite permitting and unitization.

Meanwhile, we've assembled a team of key contractors who will provide design and construction services if we're able to develop Badami.

Our strategy is to reduce costs, encourage efficiency and innovation, and enhance the competitiveness of Badami investments by working together with contractors early in the process and sharing risks and rewards through team incentive contracts.

While some of our existing contractor alliances in Alaska incorporate the concept of shared risks and rewards, they've been based essentially on individual rather than overall project performance. In some cases, this has pitted the interests of one contractor against the interests of others, at the expense of overall performance.

By setting team targets for contractors working on the Badami project, we hope to more closely align everyone's interests in achieving common goals. We'll win together ... or we'll lose together.

This is a new way of doing business in Alaska, and it's the kind of innovation and teamwork we need in order to overcome the challenges posed by marginal projects. It has already played a crucial role in two BP developments in the North Sea: the Hyde and Andrew fields.

Like Badami, both Hyde and Andrew are marginal projects. Neither could compete effectively for funding under traditional development schemes.

Hyde, a small gas reservoir in the southern region of the North Sea, experienced its initial breakthrough when horizontal drilling technology significantly reduced drilling costs. But the project manager was concerned that taking a traditional approach to fabrication contracts would undermine the gains made through horizontal drilling. The contractor would always try to bill BP for the maximum number of man-hours possible, and BP would assign legions of its own staff to oversee the activities of the contractor and make sure we weren't being overbilled. Sound familiar?

A small team of BP personnel and the design, fabrication and installation contractors was assembled. They quickly decided to dispense with the normal

legalese in their agreements and established a mutually agreed-upon framework for sharing risks and rewards.

Hyde was developed. Costs came in at less than 80 percent of original estimates. BP saved money. In addition to their normal profit margins, contractors earned an additional 15-20 percent in performance bonuses. Everyone from managers to roughnecks on the rig floor received a sizeable bonus. Win-win.

A similar approach is being taken with Andrew, a 100 million-barrel oil field in the central North Sea. A target cost has been established by a team of BP and seven contractors. If the project is delivered at that cost, contractors will earn their normal profit margins. If costs come in under estimate, the savings will be split 60 percent to the contractors and 40 percent to BP. If there's a cost overrun, BP and all of the contractors will share the liability, though the contractors' risk is capped.

To date, the team has saved 2 percent from the target cost and identified another 4 percent in savings. That's in addition to not spending any of the 10% contingency built into the original target. The team now has a stretch target of delivering the project at 20 percent under the team target. Win-win.

Did I mention that in both instances, the contractors were initially suspicious of BP's motives?

I recognize that change breeds uncertainty ... and that uncertainty breeds skepticism. But it's already been proven elsewhere that this new team approach works. It can work in Alaska, it will work in Alaska, and we want contractors with a commitment and a track record to make it work.

Projects like Badami and the Milne Point expansion won't offset the decline of Prudhoe Bay. They *do* hold the key to minimizing overall production decline through this critical period ...

... to sustaining the flow of revenues that fuel future investments for the state and the Alaskan oil industry ...

... to extending the productive lives of North Slope infrastructure and the Trans Alaska Pipeline ...

... to generating oil industry jobs for Alaskans and revenues for Alaskan businesses.

They hold the key to ensuring oil's role in Alaska's future.

The sheer magnitude of the challenges, of the opportunities, of what's at stake for all Alaskans, demands that we move on from the platitudes of partnership ... and that we sit down at the same table, roll up our sleeves, get down to the serious business and hard work of pinpointing the critical issues that face us, and find the right solutions.

What will it take to compete successfully for investment capital, and how can we work together to reinforce our common bonds and capture the prize within our collective reach? What tangible steps can we take today toward ensuring a strong and stable industry, and thereby a strong and stable Alaskan economy, tomorrow?

Perhaps a sliding-scale royalty such as we're proposing for Badami that would more closely align our risks and rewards with those of the state by linking the royalty rate with prices. Perhaps federal incentives for heavy oil development not only on the North Slope, but elsewhere, in order to boost domestic production. Perhaps investment credits or a streamlined permitting process.

However, this is not the time for demands. It is not the time for threats or hollow promises, and it is not the time for brinksmanship or posturing. It *is* the time, if we're truly committed to getting from here to there by finding a way to capture investment capital, for constructive, open, productive dialogue leading to win-win solutions for the industry, for the government and for the state.

There will be forks in the road ahead. But progress we've made in the past year has provided us with a new map that clearly signals which way we must turn.

It's clear we must choose an uncompromising commitment to environmental and safety excellence rather than allowing our performance to continue to deteriorate as it did in 1994.

It's clear we must choose to build on the framework of our strategic alliances between contractors and producers rather than settling for the mere structure of closer business relationships.

It's clear we must choose to make our past achievements a springboard rather than a crutch. Instead of fostering conformity and convention, they must inspire innovation and new ideas to clear the roadblocks standing between us and our shared goals -- the export ban, the fiscal gap, fiscal schemes and uncertainties that discourage investment in marginal projects.

It's clear we must choose dialogue over dispute in our dealings with government. We must redefine "us and them" to mean Alaska's unity as we compete globally for increasingly scarce investment capital rather than our divisiveness as we fight among ourselves.

It's clear that oil can be Alaska's future. Working together, we will find our way from here to there. We've come this far despite our past disputes. We'll reach our destination by redirecting our energies to our common foes in the competitive arena, to our shared opportunities in a healthy environment for investment ... and by getting on with the tremendous task we face together.

Union Oil Company of California

Testimony on Incentives
Senate Resources Committee
February 1, 1995

Mr. Chairman and members of the Resources Committee--My name is Kevin A. Tabler, Land Manager for Union Oil Company of California (Unocal) in Alaska. I appreciate this opportunity to be heard today and to present Unocal's comments on our concerns and possible incentives to help promote development in Cook Inlet. I emphasize Cook Inlet because Cook Inlet is where our infrastructure base and manpower is best defined. Although we do have working interests in fields on the North Slope, our ownership interest is such that we play a minor role in the development and operation of these fields. While it is recognized that any development incentives or financial relief available to North Slope producers will have a beneficial impact on Unocal, that impact is magnified when applied to the marginal nature of mature fields in Cook Inlet. For this reason I would like to limit my comments to, and address the concerns of, Unocal's operations in Cook Inlet.

Unocal's activity in Alaska started in the early 1900's, when we began selling petroleum products throughout the state. We have participated in every major lease offering and explored in geologic basins statewide. Our early successes were located in and around the Cook Inlet. It is an area we know best and one in which we have concentrated our efforts. For the last five years, we have consolidated and restructured our Alaskan operations to take advantage of our strength as the lowest cost producer in Cook Inlet. We have, through either purchase and/or exchange of properties, positioned ourselves to have the most cost effective operation possible. This cost effectiveness is evidenced by the number of active producers remaining in the Inlet today. Our Cook Inlet operations include operatorship of ten (10) of fifteen (15) platforms and five (5) of eleven (11) producing gas fields, clearly establishing Unocal as the dominant operator in the Inlet. The Cook Inlet, with its mature and declining fields, low margin properties, high operating cost and regulatory uncertainty, creates a very challenging environment in which to stay profitable. Unocal's considerable stake in its infrastructure, manpower and capital investments are continually threatened by global competition for investment dollars, low oil prices, and an uncertain and changing regulatory climate.

Unocal's operations in Cook Inlet, unlike other producing areas in Alaska, are extremely vulnerable to external influences, such as changes in effluent discharge standards for platforms and facilities and requirements for tanker escorts, both of which are under review and discussion at this time. Although these external influences are regulated by the Federal government, the State has significant input into the formulation of federal guidelines and regulations, as

they pertain to our operations, in addition to its own water quality regulations. Another area of concern and a factor in determining field life, is platform abandonment regulations also under review at this time. Additionally, product price plays a key role in any field development, but in fields which are at their economic limit, this one factor alone limits the remaining development opportunities. Any one of these external influences significantly impacts the economic viability of our operations and accelerates field abandonment. As mature fields deplete, operating costs increase. Couple this with additional regulatory constraints, and all of the reorganizations, rationalizations of properties, and manpower downsizing will have had little positive effect without a cooperative effort of all interested parties.

It is clear from my comments that we are at a critical juncture in the continued development of the existing producing fields in Cook Inlet. We need to create a more favorable climate to eliminate uncertainty. We need to take action to reduce economic risk. Otherwise, investment capital, which is extremely sensitive to field life and product price, will be hard to come by when competing on a global market.

Up to now I have concentrated on the condition of the Inlet and what is driving our decision-making process. I would like, in a broad sense, to touch upon the areas of concern expressed earlier and offer suggestions for additional investigation.

Relief for Marginal Fields in Cook Inlet

Four (4) of the ten (10) Unocal operated producing platforms produce less than 2,000 BOPD each. One (1) produces less than 900 BOPD. Expenses on all of these properties make them marginally profitable. In an effort to increase production, Unocal has committed over \$80 million in capital investments over the last two years, with the potential to spend an additional \$31 million in 1995 on these four (4) platforms. At this point, it is difficult to commit additional capital to develop these properties due to their short remaining platform lives and marginal profitability. Reducing or eliminating the State's royalty on these marginal properties could make the projects economically viable and significantly increase the economic life of the platforms, thereby maintaining employment and the associated community benefits. A variety of options exist. One is to have any reduced royalty applied to future development in the same field or area. For fields or platforms facing abandonment today, (such as a platform with less than 1000 BOPD) complete royalty relief is warranted. These properties provide minimal income to the state and complete royalty relief will extend field life and employment by one or two years. For other properties, reducing royalty based on capital investment will create value for the state and industry. Other scenarios to look at, would include a sliding scale royalty structure tied to price, production or a combination of both. It is important to

note, that what is economically viable for the Cook Inlet may not be viable for the North Slope and visa versa. A statewide application of this approach may not be appropriate. Unocal reserves its judgment as to which method or approach it subscribes to pending a more thorough economic analysis. The state currently has the ability to reduce royalty, but depending on the administration, the application of these regs can vary. State royalty reinvested into additional development opportunities could extend the life of these fields and yield more royalty for the state over the life of the field. This is truly investing in your future.

New Field Development Incentives

The State of Alaska needs a positive incentive program in order to promote exploration and development of new and/or smaller marginal accumulations of oil and gas. Alaska could reduce the royalty rate on new field exploration or eliminate royalty until payout. Allowing the recovery of all capital costs by the risk bearing parties before the state receives its royalty share would result in more development of marginal fields. The recovery of capital costs by an investing party before the non-investing party participates is a standard in the industry and a solid concept in joint venture partnerships. Granting such incentives appear possible under current regulations. Until now, prolific field production elsewhere has curtailed the need to do so. However, today's economics call for a reexamination of the utility of these incentives and the flexibility inherent in existing regulations. Another way of inducing capital expenditure is to tie the reduction in royalty rate to the amount of capital expenditure incurred. Both reductions would enhance the economic decision of investing capital in Alaska.

I encourage the state to broaden the application of exploration incentive credits. Credits are already available on some leases, but amendments to make them more accessible or useable would encourage investment.

Great movement in the right direction was achieved with SB 308 last year. Additional legislation which will enhance the lease sale process and provide stability and reliability for manpower and budgetary planning purposes is desired.

Creation of incentives and regulations pertaining to Coalbed Methane development should be encouraged as an area with huge potential. The state must determine which department has jurisdiction over this type of new development and work closely with industry to establish cost effective regulations which encourage companies to invest in this type of high risk venture.

Creating new, or expanding existing industries in Cook Inlet will help in that new markets will provide incentives to explore and develop additional reserves. We recognize there is a bit of a chicken and egg effect at work here.

The state's overriding philosophy must demonstrate flexibility and a willingness to partner with industry in trying to maximize each field's ultimate potential. I don't believe any one particular incentive will be the answer to all problems for all fields. We need a thorough review of existing statutes and regulations to assess what alternatives are already in place and a new mindset created in all departments throughout the state.

Tractor Tugs and Pilot Vessels in Cook Inlet (Tanker Escorts)

The U.S. Coast Guard is currently reviewing the applicability of tanker escorts in all U.S. waters. Currently, Cook Inlet is exempted from this practice; however, there is a mounting surge of enthusiasm by the commercial fisherman and environmental groups to impose tanker escorts in the Inlet. Expensive tanker escort tugs would cost \$5 million per tug per year to implement. I believe there are other ways of addressing the concerns of commercial fisherman and environmental groups. If we work together to implement vessel tracking systems, establish vessel traffic lanes, activate additional navigational aids, etc., I am convinced we can address the concerns of all without imposing unnecessary, costly and oppressive restrictions which will significantly reduce the economic life of the producing fields in Cook Inlet. The state needs to take a proactive posture in protecting its royalty investment. The incentive already exists for the state and industry to seriously address this issue. There are significant benefits to the local community through employment and local purchase of goods and services when we invest millions of dollars working over existing wells and drilling new ones. If we are forced to divert our funds toward escort vessels, most likely the owners will not be Alaskan and that money will flow out of the state.

Water Quality Issues

There are three water quality issues significant to continued operations in Cook Inlet: revision of the State of Alaska Water Quality Regulations (phase I and II); EPA's Coastal Effluent Guidelines for Oil and Gas Industry, and EPA's Cook Inlet/Gulf of Alaska General National Pollutant Discharge Elimination System (NPDES) permit.

Water Quality Regulations and the Coastal Effluent Guidelines will determine the conditions of the renewed Cook Inlet/Gulf of Alaska NPDES permit. Unocal currently discharges a variety of effluents, primarily-produced water, drilling muds and cuttings, under the existing NPDES permit. Continued operation of Cook Inlet facilities requires continued discharge under the new permit.

Water Quality Regulations

In December, 1994, Phase I of the triennial review of the State Water Quality Standards was signed into effect. In January, 1995, the Sierra Club Legal Defense Fund filed a petition requesting that the new regulations be repealed or amended so that more stringent requirements can be implemented. In response to the petition, the Knowles administration decided to open a public comment period on the new regulations to review the decisions that were made. While Unocal did not support all of the Phase I revisions, we encourage the State of Alaska not to modify the revisions. Unocal would like to work with the administration and ADEC to ensure that the issues are properly addressed.

Coastal Effluent Guidelines and Cook Inlet/Gulf of Alaska General NPDES Permit

The Environmental Protection Agency (EPA) is in the process of drafting both the Coastal Effluent Guidelines for oil and gas industry discharges and the Cook Inlet/Gulf of Alaska General NPDES Permit. ADEC will have an opportunity to comment on the guidelines and permit when issued in the near future. A zero discharge of effluents from Cook Inlet facilities would result in premature closure of the Trading Bay and McArthur River Fields due to retrofit costs exceeding \$50 million. This would result in lost revenues of over \$500 million, most of which goes to the local community, and approximately 800 lost jobs. The state would lose nearly \$100 million in royalties and taxes.

It is important that the State coordinate comments between all State agencies supporting technically and economically based guidelines and permits for Cook Inlet's oil and gas operations.

Platform and Pipeline Abandonment Regulations

Unocal has worked closely with other industry representatives concerning modification of the existing Alaska Oil and Gas Conservation Commission (AOGCC) Regulations affecting platform abandonment. On September 14, 1994, testimony was given during public hearing to support new regulations which, if adopted, would significantly reduce the cost of platform and pipeline abandonment. The AOGCC recognized some time ago the need for a cooperative and joint effort in updating and revising its existing regulations to address the concerns of operating in today's business and environmental climate. They are to be commended for their partnering efforts introduced early on in the review process. Their initiative to review outdated regulations created the incentive and opportunity for industry to provide input and hopefully certainty

into the abandonment process. If the proposed regulations are implemented as suggested, this fiscal and environmentally sound determination will have an extremely positive effect on field economic life.

Examples of the types of proposed results achievable are as follows:

Current regulations call for the platform site to be completely cleared of all equipment and structures. The proposed plan calls for the site clearance of only obstructions that would interfere with fishing or shipping interests. This would not result in complete site clearance, the towers of the platforms would actually be left on bottom and corrode away over time.

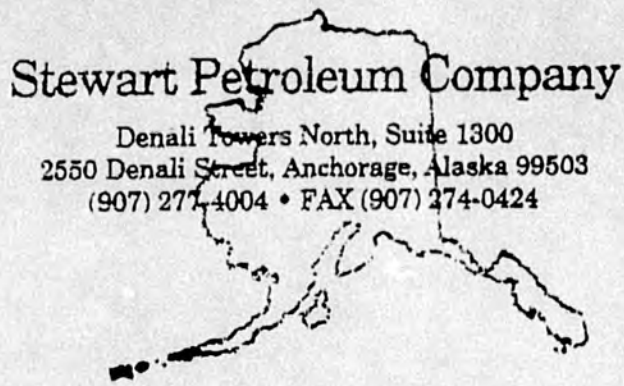
Current regulations call for the platform pilings and casing strings to be cut off fifteen (15) ft. below the mud line. A fifteen (15) cut off below mud line is extremely unsafe for divers due to the strong current and low visibility in the Inlet. Washing around the legs of the platform to make this cut could destabilize the platform further endangering divers. A cut off one (1) ft. below mud line accomplishes the same objective and is proposed.

Pipeline abandonment procedures are not specifically addressed in the current AOGCC Regs. The opportunity was taken to propose regulations that would deal with this issue. Abandonment of pipelines in place is a common way of handling pipelines, it's relatively inexpensive and has a negligible environmental impact while providing industry with increased certainty for economic field life analysis.

A waiting period of ten (10) years after cessation of platform utility was also included in the proposed regulations to allow the operator to abandon platforms in groups rather than one at a time. This of course would lower abandonment costs by taking advantage of economies of scale.

In conclusion, I would like to thank the committee for actively seeking input on possible incentives, which if developed and applied would have a profound impact on the way we approach the shared responsibility for the future of the oil industry here in Alaska. Recognition of the problem and proper diagnosis are the first steps in finding a cure for the ailments we are experiencing in the state's most vital industry.

Thank You



Stewart Petroleum Company

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(907) 274-4004 • FAX (907) 274-0424

February 1, 1995

Re: Testimony on
Oil & Gas Incentives
Senate Resources Committee

VIA FACSIMILE (465-3810)
ORIGINAL MAILED

Senator Loren Leman
Alaska State Capitol
Juneau, AK 99801-1182

Dear Senator Leman:

Stewart Petroleum Company is a small independent oil and gas exploration and production company based in Alaska. We are active in Alaska and seven other states. Our current area of interest within Alaska is Cook Inlet Basin. We have been fortunate in discovering an oil field of significant size on the west side of Cook Inlet and are in the early stages of development of that field (named West McArthur River Oil Field) at the present time. With a pipeline system in place, production of the discovery well and one development well is underway. According to available information, we are the first independent company to establish commercial oil production in Alaska in modern times.

It is my understanding that the committee is exploring possible incentive programs for development and production of oil and gas in Alaska. Due to lack of preparation time for today's hearing, we are limiting testimony to a few major areas as follows:

1. Royalty Incentives

The State of Alaska had a discovery royalty program in effect until its abolishment in the early 1970's. Under the program, royalty burden on a discovery lease was reduced from 12.5% to 5% for a period of ten years. Any and all wells located on the lease received the reduction. Perhaps this program or some variation thereof could be reinstated. The incentive created would result in more aggressive development schedules.

Mr. Loren Laman
February 1, 1995
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2. Make Acreage Available

At about the same time the discovery royalty program ceased to be, all State lands were classified for competitive bid only and prior non-competitive programs were eliminated. The Federal government and many oil producing states maintain non-competitive leasing programs. The mentality in Alaska has been to maximize lease bonuses. It can be better for both industry and State if those dollars go into exploration and development activities resulting in long term production of oil and gas.

3. Simplify Permitting

Alaska's permitting system is overwhelming and often counter productive. Changing the system will not be easy. A "lead agency" concept for oil and gas may be a solution but not if it is simply another layer of regulation. The lead agency would have to replace the existing permitting functions of other agencies and provide "one stop shopping" for industry. Also, reasonable time limits for issuance or rejection of a permit are needed.

4. Reduce DEC Financial Responsibility Requirements

These requirements were created in the wake of the Exxon Valdez incident. Even with the reductions enacted last year by the Legislature, the required coverages are very hard to come by for a small company, especially with the "Direct Access" provision.

5. Create Development Funding Programs

With Alaska's high cost of operating, State funding for development activities would significantly encourage exploration and more discoveries by the independent sector. A development loan program, which would be available only after discovery in paying quantities, would encourage aggressive development and benefit both the State and industry. I know from experience that oil and gas operations do not fit the AIDA programs. A new funding mechanism would be required.

Our project at West McArthur River has involved more than \$42 million in investment to date. During periods of drilling, approximately 40 full time on-site jobs are created together with approximately 20 support jobs in Anchorage or Kenai. Pipeline construction involved approximately 30 full time on-site jobs and 15 support jobs. After full development of the field, about 15 permanent on-site and support jobs will be involved in producing operations. Upon full development of this field, we estimate taxes and royalties to the State of Alaska will exceed \$6 million per year. Total revenues to the state are estimated at more than \$100 million over field life.

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Independents can function in Alaska, but these types of incentives are needed. As an independent producer, we are in touch with many other independent producers. There are roughly 10,000 members in IPAA, the Independent Petroleum Association of America. Most of the IPAA members will never venture to Alaska, but in the wake of our success, we are beginning to hear expressions of interest from quite a few.

Thank you for your consideration. We look forward to continued work with the committee and we are prepared to assist with specific language to accomplish these suggested changes.

Sincerely,



W. R. Stewart
President

WRS:rs

Alaska Oil and Gas Association



121 W. Fireweed Lane, Suite 207

Anchorage, Alaska 99503-2035

Phone: (907)272-1481 Direct: (907)272-7424 Fax: (907)279-8114

L. A. (Ardie) Gray, Public Affairs Manager

January 31, 1995

The Honorable Loren Leman, Chairman
Resources Committee
Alaska State Senate
Capitol Building
Juneau, Alaska

Dear Senator Leman:

Attached, for your information and reference, is a synopsis of Alaska oil and gas taxes and a listing of current incentives.

The listing of incentives was compiled by AOGA based on conversations with agency personnel from the Departments of Natural Resources and Revenue. Input also was received from Gordon Harrison, Legislative Research Agency. Information on the application of some of the incentives was based on the recollection of agency staff.

Please let us know if we can be of any additional assistance.

Sincerely,

A handwritten signature in cursive script, appearing to read "L. A. Gray", is written over the typed name and title.

L. A. GRAY
Public Affairs Manager

Attachment

B:\agf.Sres.incentives

ALASKA**CURRENT TAXES**

Income Taxes	9.4% Corporate Income Tax
Property Tax	20 mils/2% of assessed value
Severance/Production	Gas 10% of Market Value or \$0.064 per MCF, whichever is greater Oil 12.25% of Market Value for first five years 15% after first five years or \$0.80 per barrel, whichever is higher. * Oil Oil and Gas Severance Taxes subject to Economic Limit Factor (ELF). See Below.
Conservation Tax	Gas 4 tenths of a percent per 50,000 cubic feet of natural gas Oil 4 tenths of one percent per barrel with conservation surcharge of \$0.03 and \$0.02 per barrel of crude oil to fund Oil and Hazardous Substance Release Prevention and Response Fund (\$0.02 per barrel surcharge suspended when Response Account balance equals \$50 million.)

ECONOMIC INCENTIVES - PRODUCTION/DEVELOPMENT

AS 43.55.013 - Economic Limit Factor - The respective severance tax rates for oil and gas are reduced by a field's ELF. During the life of a field, production diminishes faster than operating costs. At the economic limit total costs including operation costs, royalties and production taxes exceed gross revenue and the field becomes uneconomic. Production tax rates for each individual field are modified by the economic limit factor (ELF) which is a value between zero and one. The ELF is a factor which is multiplied by the nominal production tax rate to derive an effective production tax rate for each field. The ELF varies based upon a field's size, as measured in total throughput, and by the field's average per well productivity. **Severance taxes paid on oil production** - Of the 26 producing leases or properties, four major fields pay the majority of severance taxes, two fields pay nominal severance taxes.

Co-Mingling: 15 AAC 55.027 of the new production tax regulations (effective Jan. 1995) will allow producing fields to share facilities while maintaining each field's "distinct field" status for ELF purposes. Three "sets" of fields are currently sharing facilities. No application for co-mingling/shared facilities has been denied. Section 027 of the new regulations provide for appealing DOR's decision if an application is denied. The Commissioner of Revenue makes the ultimate decision.

Non-Taxed Produced Gas 15 AAC 55.151 (a) of the new production tax regulations allow free use of gas for enhanced recovery purposes.

Alaska Incentives**Page 2**

AS 38.05.180 (j) - Royalty Reduction After two years of lease production, royalty may be reduced to prolong economic life of a field. Lessee must show revenue is insufficient to yield a reasonable rate of return. According to Dept. of Natural Resources, only one has been granted in the recent past (Note-information from DNR is not conclusive). The DNR Commissioner has ultimate authority to approve royalty reduction.

Code Sec. 43 - EOR Credit Federal Enhanced Recovery income tax credit deduction may be claimed on state income tax. May be taken as a line item deduction on state income tax return. DOR does not have compiled information on number of companies or amount of credits claimed or allowed.

AS 43.20.042 - Industrial Incentive Credit of 10% of cost for gas processing projects applied against income tax. May be taken as a line item deduction on state income tax return. DOR does not have compiled information on the number of companies or amount of credits claimed or allowed. Through the audit process claims can be contested or denied. Appeals are handled through the existing appeals process i.e., informal conference and formal hearing process. The Commissioner of Revenue ultimately signs the findings of the formal hearing.

AS 38.05.180 - Discovery Royalty Credit - Repealed by Chapter 65 SLA 1969 - Provides that a lessee who makes first discovery of oil or gas in commercial quantities in a geologic structure pay a royalty of five percent for 10 years following the date of discovery and 12.5 percent royalty thereafter. Some leases issued up to the point of repeal could still qualify.

ECONOMIC INCENTIVES - EXPLORATION

AS 38.05.180 (l) - Exploration Credits Provides for a credit of up to 50% of certain exploration costs that can be applied against royalty, rentals and severance taxes due the state. This provision is accomplished by state leases. Covers two years following the lease sale and applies to well footage drilled and geophysical costs. Geophysical data must be made public. EIC has been offered in 10 sales. Credits have been granted on 20 EIC wells. Only one application for credits has been denied recently, according to DNR (Note-information from DNR is not conclusive). 11 AAC 83.820 defines the process for appeal to the DNR Commissioner, who makes the final decision.

NEW EXPLORATION INCENTIVES

AS 41.09.100 - Exploration Incentive Credits Provides for a credit of \$5 million per project (total of all credits \$30 million) for geophysical work, exploration or strat test wells. Credit may be applied against taxes or bonus payments. Credit may not exceed 50% of eligible costs on state-owned land and 25% on land not owned by the state. Credit must be used within 5 years and may be assigned. Data confidential for 24 months. Status - Regulations pending.

Exploration Licensing Provides for licensing of up to 500,000 acres conditioned upon an obligation to perform a specific work commitment. (Maximum acres which can be held under license 2 million acres.) Gives licensee option to convert to lease upon completion of work commitment. Status - Regulations pending.

AOGA key policy issues recommendations

The 17 AOGA member companies identified and developed consensus positions on the following key issues which, if resolved, would enhance oil and gas development to the benefit of industry and the State of Alaska.

AGENCY	DESIRED ACTION	BENEFIT
REVENUE	Initiate an independent review of state tax audit and appeals process.	A timely, fair, impartial tax audit and appeals system will benefit both the state and the industry by cutting back the amount of expensive and time-consuming litigation, giving needed certainty as to what taxes are actually currently owed.
REVENUE	Clarify and simplify regulations for taxable value of production and ROI for tankers.	The issues of prevailing value and "ROI" have been a continuing source of complex, changing and inconsistent audit decisions over the years, resulting in continuing rounds of controversy and litigation. The industry and the state would benefit from simple-to-apply, and as a result, timely and litigation-free rules for these two issues.
NATURAL RESOURCES	Develop policies and regulations which accomplish the certainty of lease closure.	Adoption of policies and regulations will provide guidance to both state and industry on the full extent of obligations upon lease termination.
NATURAL RESOURCES	Implement an oil and gas leasing policy work session to improve and strengthen the state's leasing program.	A predictable oil and gas leasing program allows the state, public, local governments and the industry to efficiently plan for oil and gas related activities and fiscal expenditures.
ENVIRONMENTAL CONSERVATION	ADEC should (1) implement water quality regulations developed during final Phase I of the Triennial Review; (2) establish an Advisory Group process for Phase II that will result in timely development of scientifically-based Standards; and (3) coordinate with other state agencies in comments to EPA supporting technically and economically based Coastal Effluent Guidelines and NPDES permits.	These regulations will set the stage for standards to be developed under Phase II. Restructuring the Advisory Group to a smaller number of participants who are empowered to represent their constituencies and are allowed to participate in the drafting of regulatory proposals will increase the efficiency of the process and ensure the concerns of Alaskans are appropriately considered. Coordination of a state response to EPA proposals governing offshore discharges will ensure the state's interests in both environmental protection and continued oil and gas production are considered.
ENVIRONMENTAL CONSERVATION	Streamline oil spill prevention and response requirements.	Limited public and private resources will be reduced without sacrificing protection.

<i>AGENCY</i>	<i>DESIRED ACTION</i>	<i>BENEFIT</i>
ENVIRONMENTAL CONSERVATION	ADEC should adopt air quality regulations which incorporate recommendations received from the regulated community; centralize the permit program in Anchorage; and report regularly on program and administrative costs and fees.	Adoption of a state program ensures the unique conditions faced by Alaska facilities are recognized and allows the state to set fees which are fair and equitable. Administration of the program by a centralized function operating out of Anchorage will result in reduced program costs, increased permitting efficiency and consistent statewide permit decisions.
ENVIRONMENTAL CONSERVATION	ADEC should provide for flexible solid waste management regulations for municipal landfills and facilitate permitting a new North Slope Borough landfill near Deadhorse.	New federal landfill criteria could drive small communities to avoid permitting a landfill altogether, leading to the potential for open dumping and environmental degradation. Unless EPA allows the state to have added flexibility in the management of local landfills, the state may have to provide financial assistance to small bush communities in order to establish compliance, thereby increasing the demand on state funds at a time when oil and gas revenues are declining.
ENVIRONMENTAL CONSERVATION	ADEC should promulgate Solid Waste Regulations that provide for timely, cost effective closure of reserve pits.	Adoption of appropriate regulations will add clarity and certainty to the process, facilitate state decision-making on these reserve pits, and resolve long-standing reserve pit issues.
GOVERNOR	A task force should be established to review authorities and regulations governing oil and gas operations to identify opportunities for consolidation and elimination of redundancy.	The independence and funding of the Alaska Oil and Gas Conservation Commission is fundamental to the state's interests. Identification and elimination of overlapping or duplicative authorities will result in increased efficiency of state agencies, with commensurate savings of state expenditures.
GOVERNOR	The State should work with Alaska Stakeholders and the Congressional Delegation to secure legislation in the 104th Congress addressing Alaska's wetlands problems.	Development of reasonable wetlands legislation and regulations and adoption of policies which recognize the unique position of Alaska will allow development of needed infrastructure in coastal communities and allow Alaska's resources to be developed without sacrificing environmental protection.
GOVERNOR	The State should encourage the USFWS to develop a Polar Bear Habitat Conservation Strategy that does not restrict subsistence activities or access to lands such as ANWR and offshore areas.	State involvement in commenting on this federal initiative will protect the state's interests in development of resources on state lands and subsistence rights of native Alaskans.

House
Res 2/15/95

❖ ARCO Alaska, Inc.

House Resources Committee

Agenda



Common Goals

International Competitiveness

What it Takes

Immediate Actions

Next Steps

Common Goals



The State and ARCO Share Important Common Goals

Jobs for Alaskans

Incremental Revenues

- **No Changes in Producing Reservoirs in Existing Fields**
- **Opportunity to Increase Permanent Fund Contributions, While Maintaining Current Contribution Levels**

Achieved By Sustained Economic Development

- **Exploration**
- **Marginal Developments**
- **Extension of Field Lives**

To Achieve Sustained Economic Development the Environment Must be Competitive

Worldwide Fiscal Regimes are Getting More Competitive

 **Low Cost
& Long Term**

EXAMPLES:

Australia introduced Resource Rent Tax in 1985 for offshore projects.

Venezuela:

Income tax rate for extra heavy crude developments lowered from 67% to 34%

Removal of onerous tax provisions for multinational firms

Alberta/Canada: Fiscal reformations lead to oil&gas industry turnaround after 1986 crash.

Norway abolished royalties on new fields in 1986. Removal of Sliding Scale state participation for new leases in 1992.

UK abolished royalties on new fields in 1984 and PRT for new fields in 1993, leading to a revival of UK oil industry.

Fiscal Regime Comparison as of 1994 (New Fields)

**APCO
Safe** **Low Cost
& Long Term**

	<u>Alaska</u>	<u>U.K.</u>	<u>Australia</u> (Offshore)
Profit taxes			
Corp. Income Tax	39%	33%	33%*
Revenue Taxes			
Royalty	13%	0% after 1984	0% after 1985
Production Tax	0-15%	-	-
Other			
Ad Valorem Tax	2%	-	-

* In addition a Resource Rent Tax kicks in once oil co's earned a return on investment. For marginal developments, this would add 0 to 5%pts at today's prices, and about 10%pts at \$20 WTI.

Summary of Worldwide Fiscal Regimes (Petroconsultants, 1994)

Safe Low Cost
& Long Term

Number of Fiscal Systems by Category

<u>Production Sharing Contract</u>			<u>Tax/Royalty System</u>			<u>Total</u>
Standard PSC	<u>w/ Royalty</u>		Profit- Based Tax Only	<u>Royalty</u>		
	Variable	Fixed		Variable	Fixed	
19	7	9	8	10	17	<u>70</u>

Countries > 200 MBOPD

9	1	5	3	1	3	<u>22</u>
Indonesia Oman Qatar Egypt Ecuador India Libya Angola Syria	China	Yemen Malaysia Algeria Columbia Gabon	U.K. Norway Australia	Canada	U.S. Argentina Nigeria	

What it Takes



Work With the State to Develop That Competitive Environment

- **Support State's Effort to Achieve Soft Landing**
- **Develop Competitive Tax / Royalty Structure**
- **Transition to More Flexible Regulatory Environment**
- **Industry Must Focus on Keeping Cost Structure Low**

Immediate Actions for the Short Term



Review / Clarify Legislative Intent for Application of Existing Incentives

- **Exploration Incentive Credits**
- **Lease Sale Schedule**
- **Discovery Royalty Credit**

Review / Support Flexibility in DNR to Provide Royalty Relief

- **Lease Sale Terms**
- **Smaller Discoveries**
- **Prolonging Economic Life**

Support Calls for Federal Tax Incentives for Oil and Gas Development

Next Steps for the Long Term

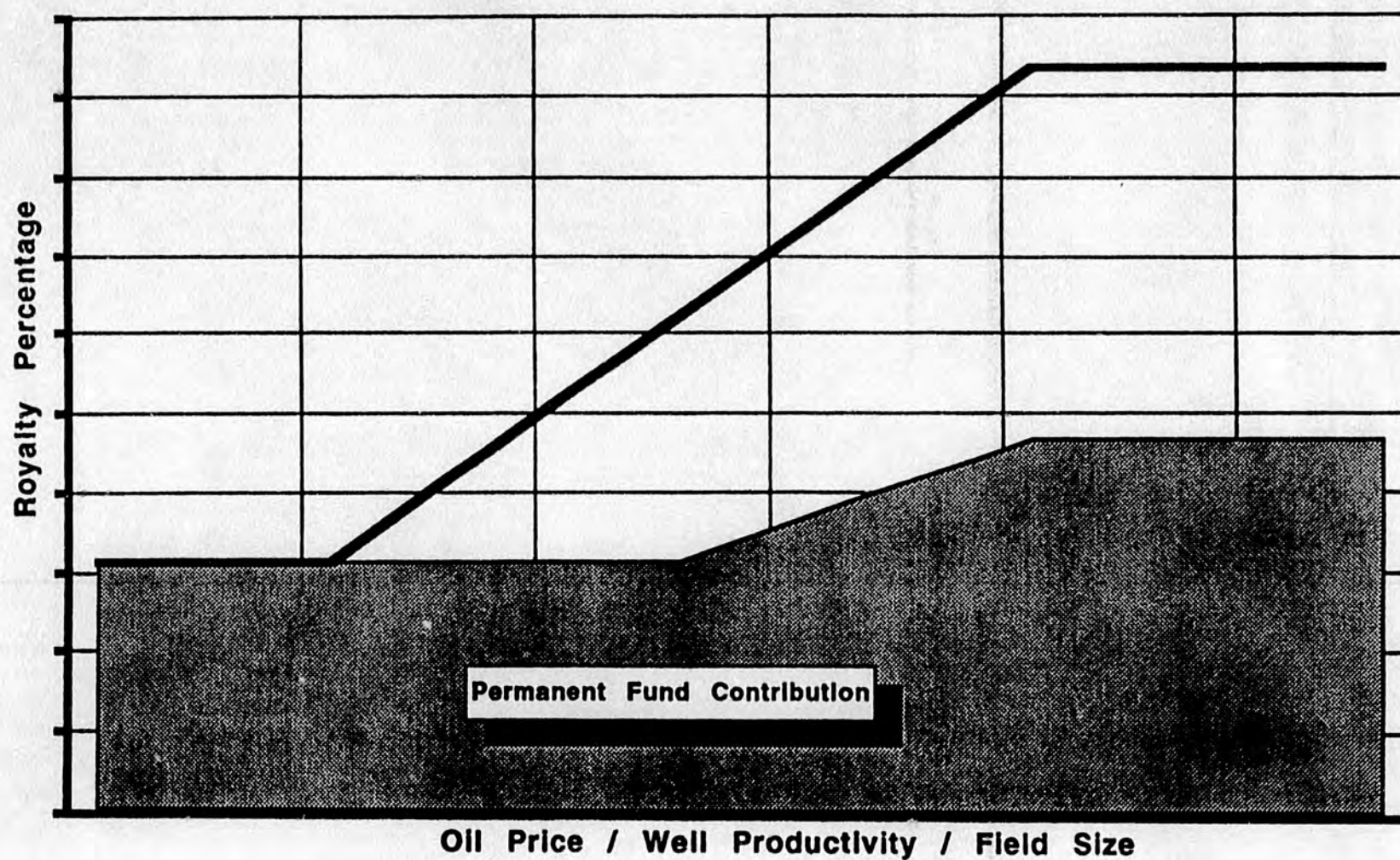


Implement the Process Described Below to Examine Alaska's Long Term International Competitive Position and Recommend Alternative Proposals for Legislative Consideration

- **Legislative / Administrative / Industry Cooperation**
- **Focus First on Gathering Information on Competitive Fiscal Regimes**
- **Develop a Broad Range of Options**
- **Narrow Finally to Specific Proposals for Legislative Action**

Conceptual "Fixed-Variable" Royalty

safe Low Cost
& Long Term



Potential "Project Partnering"



Whatever the New Tax/Royalty Regime Decided for Alaska

— There May Still be Projects on the Non Competitive Margin

For Those Projects Where the State's New Changes Aren't Enough

— ARCO Will Propose a "Project Partnering" Approach

ARCO Would Come Forward With Information Shared Openly

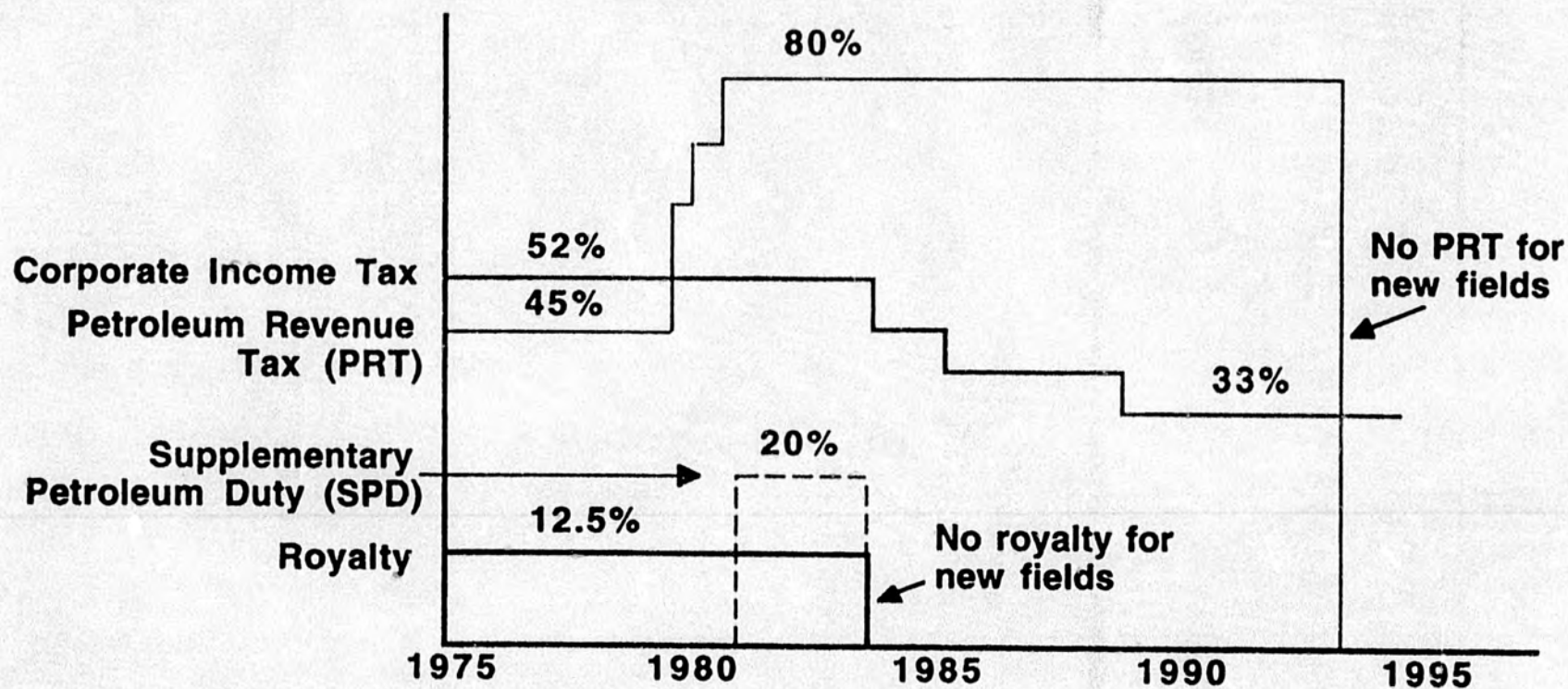
— The State Would Decide

Potential Categories of Projects For This "Project Partnering" Process

- **New Marginal Exploration** (eg, Lease Sale 79)
- **Marginal Development, New Field** (eg, West Colville)
- **Marginal Development, Existing Field** (eg, West Sak)
- **Fields Near Abandonment** (eg, Cook Inlet or Kenai)

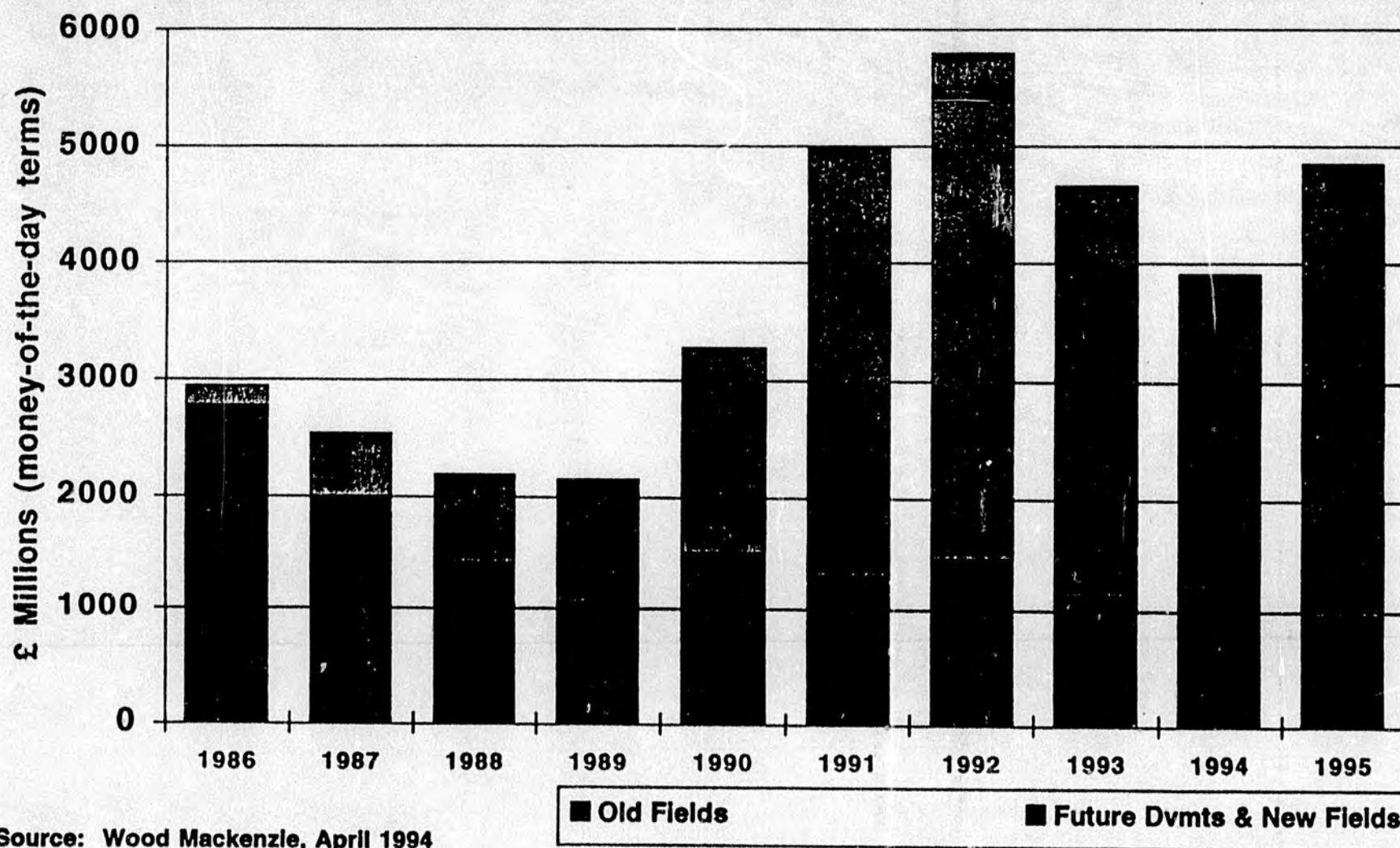
U.K. Taxation History Overview (New Fields)

AND safe Low Cost
& Long Term



Capital Expenditures U.K. North Sea

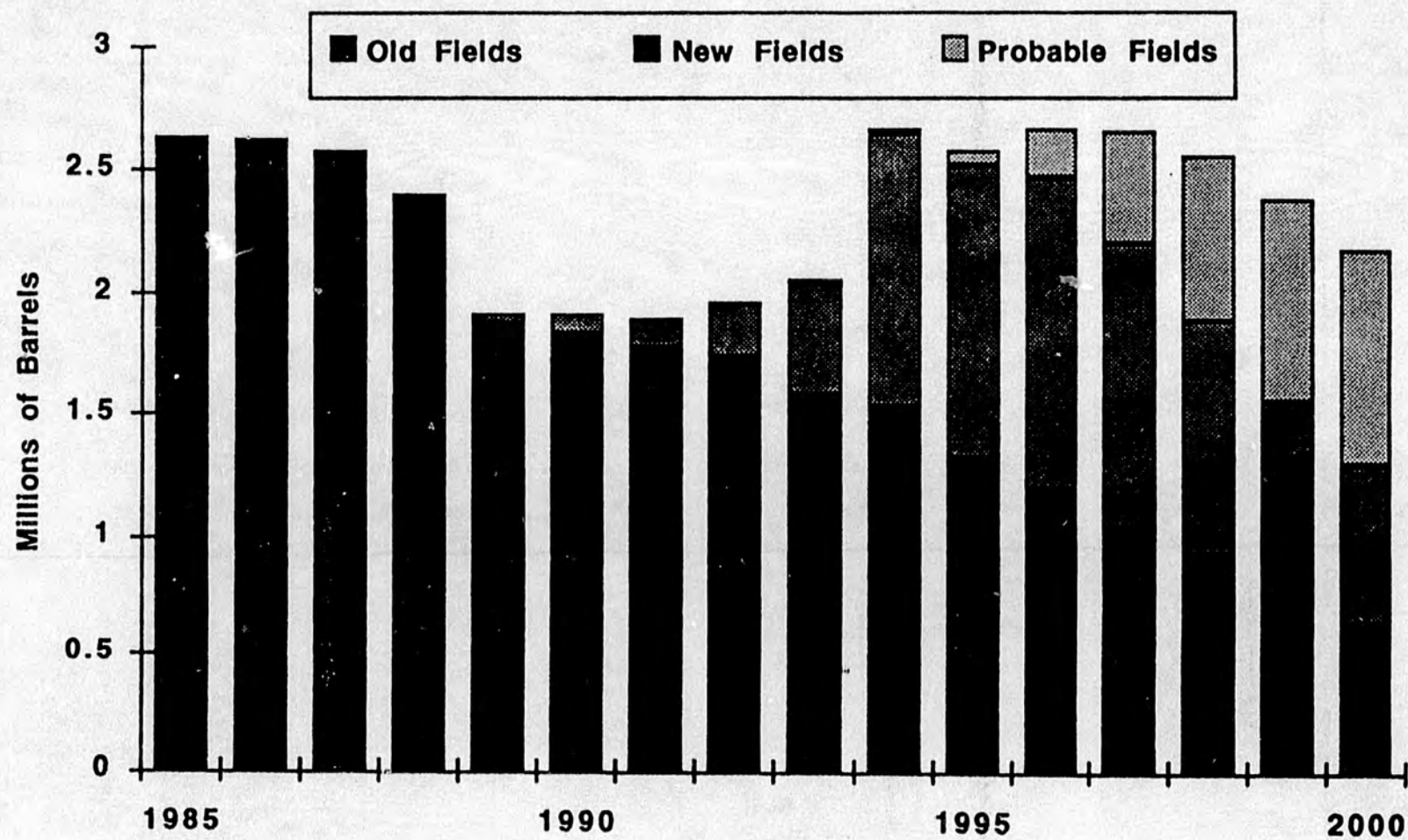
safe **Low Cost
& Long Term**



Source: Wood Mackenzie, April 1994

UK North Sea Production Profile

safe Low Cost
& Long Term



**Testimony
of
J. Ken Thompson
President, ARCO Alaska, Inc.
to
the
House Resources Committee
February 15, 1995**

Slide 1: Agenda

- Hello. For the record, I'm Ken Thompson, President of ARCO Alaska, Inc.
- Pleasure to be here. Thanks for opportunity to testify.
- Here today to talk about common goals shared by ARCO Alaska and the state.... and what its going to take to achieve our goals.
- I'll be sharing information about what other oil provinces are doing to boost production and create jobs for local residents. And I'll talk about some steps we can take today and in the future..... to ensure that oil and gas investment opportunities in Alaska remain competitive. When I'm done, I hope you'll be persuaded that the state can make a difference..... that the state can change the economic equation for marginal oil accumulations on the North Slope.

Slide 2: Common goals

- State and ARCO share common goals.
- The first is to mitigate the production decline now occurring in existing fields through the discovery and development of new oil accumulations and the development of marginal horizons in existing fields.

- Second..... we need the incremental revenue that will be derived from new production.

- Let me underscore the words "New Production." ARCO is not seeking changes in the tax or royalty treatment of existing production. Instead, we're asking that the state be willing and able to consider changes in the regulatory, tax and royalty treatment of marginal projects which can't go forward without such consideration. In short..... we must work together to turn zeroes into positive numbers.... which show up on our balance sheet and in your treasury. Or as was said on a recent Juneau news report..... half a loaf is better than none.

- If we can turn zeroes into positive numbers..... then you'll have the opportunity to increase Permanent Fund contributions over what they would otherwise be.... while maintaining current contribution rates.

- Finally.... we want to create jobs and economic opportunity for Alaskans. Those who work in our industry and those who don't.

- The only way to reach these common goals is through sustained oil and gas development. That means:

- Continued exploration of Alaska
- Development of marginal oil accumulations
- And by extending the economic lives of existing fields.

- To have sustained oil and gas development we must be competitive.

- Companies like ARCO must reduce costs through improved operating practices and development of new, more cost effective technologies.

- And the state must be willing and able to consider changes in the tax, royalty and regulatory treatment of proposed oil and gas

projects when change is necessary to turn a zero.... into new production..... new revenues..... and new jobs.

- We both have parts to play.
- There's a lot at stake.
- 85 percent of current state revenue dependent on oil production. According to state projections.... North Slope oil production will decrease more than 30 percent over next five years.

Slide 3: World fiscal regimes more competitive

- Other countries are turning zeroes into jobs, production..... and incremental revenue.
- Norway abolished royalties on new fields in 1986 and removed sliding scale state participation in new leases in 1992.
- Australia introduced a Resource Rent Tax in 1985 for offshore projects.
- Venezuela cut the income tax rate for heavy crude development from 67 to 34 percent. Removed onerous tax provisions for multinational firms and improved bidding structure for operating contracts for marginal fields.
- In Alberta, Canada fiscal reformations led to oil & gas industry turnaround after the 1986 crash.
- Why all this change? Simple. Oil Prices are down and have been down for some time. Investment capital is in short supply and there is an abundance of oil and gas investment opportunities available.
- Mr. Chairman... members of the committee I'm an here today as one of Alaska's oldest and best customers. We've been doing business here more than 40 years. It's been a tremendous relationship. I like shopping in your store. I like the merchandise

you carry. I want to keep shopping here. But a giant discount warehouse has moved in across the street. The merchandise is excellent.... and the terms are better. To survive.... to prosper.... Alaska and the companies that do business here must meet that competition.

Slide 4 – UK fiscal history

- This graph shows how the United Kingdom has moved, incrementally.... and systematically to ensure the continued competitiveness of the North Sea.
- In 1984 they eliminated royalties on new fields.
- In 1993 they eliminated the Petroleum Revenue Tax, which is similar to Alaska's severance tax on new fields.
- Today....depends on 33 percent corporate income tax to collect incremental revenue on new production.

Slide 5 -- Fiscal regime comparison as of 1994

- This slide compares fiscal regimes in UK, offshore Australia and Alaska.
- All have corporate income taxes. In Alaska combined state and federal take is about 39 percent. (35% federal plus 9.4% state equals 39% total because of deductibility of state taxes on federal returns.)
- Of the three.... only Alaska has royalty, severance and ad valorem on new fields.
- Now, you've had a look at the competition. Now.... what can we do to ensure that oil and gas investment in Alaska remains competitive with opportunities elsewhere in the world?

Slide 6 - Summary of world wide fiscal regime comparisons

- During 1994, Petroconsultants surveyed the oil and gas fiscal regimes in 70 countries.
- Survey shows that 18 of the 22 nations with production greater than 200 M bopd rely on production or profit sharing arrangements to derive revenue from oil and gas production.
- Alaska, and the United States are not among the 18. Alaska and the United States are among only three countries which still employ a fixed rate royalty.

Slide 7 - What it takes

- Industry, state must work together to create competitive environment.
- Industry must focus on keeping cost structure low.
- State -- faced with declining production and revenues -- faces many of the same challenges. We support efforts to gradually balance spending with revenues, closing fiscal gap and achieving soft landing.
- Encouraged by what we're hearing from Administration, Legislature about budget discipline. Closing fiscal gap will increase investor confidence in Alaska.... and give us confidence that any incentives you provide today..... will be honored tomorrow.
- State must develop a more competitive tax and royalty structure for new fields. Alaska must meet the competition.
- Finally, the state must be willing and able to consider alternative business arrangements when necessary for marginal projects. Current regulations may not provide necessary flexibility.

Slide 8 -- Immediate actions

- I know that many of you are eager to take immediate action to improve Alaska's competitiveness. I'm encouraged by your enthusiasm and willingness to consider positive change. However, we must move carefully, coordinate among the legislature, the administration and industry and ensure that the steps we take are the right steps and will be effective.

- That's why I'm recommending today that your first step be a comprehensive review of the incentives the Legislature has already approved.

- Are they being used effectively? Are they being used in the way you intended? Are they obtaining the results you expected?

- **Exploration Incentive Credits:** State has exploration incentive credit program. DNR still grappling with how to administer. Rules, guidelines unclear as to what qualifies, what doesn't. In fact, regulations don't exist yet.

- In the last year, we've approached DNR three times. We've been turned down three times. We're concerned about the final form these regulations will take and believe that in order to be effective, the incentive must apply to a broad range wells.

- For example.... any well that meets the IRS / SEC definition for an exploratory well. Simple, straightforward application of exploration incentive credits could increase the number of exploratory wells drilled in Alaska every year, attract outside capital to Alaska and increase the likelihood of additional commercial oil discoveries.

- **Lease Sale / Land Access:** Existing program not working well. State having difficult time maintaining sale schedule. Even when sales occur, lawsuits likely. Increased certainty created by HB 308 appreciated. The administration and legislature worked well together to enact that law.

- **Discovery Royalty Credit:** Currently covers only the lease on which the discovery well is drilled. Good for ten years from date of discovery. Time required to permit, develop Alaska

discoveries reduces value / incentive of this credit. This credit would provide more of an incentive if, for example, the credit were applied for five years from date initial production and / or were applied to leases covering the entire discovery. This would make investment in the new fields more attractive because the credit would lower our up front development costs.

SUPPORT FLEXIBILITY DNR ROYALTY RELIEF

- **Prolonging Economic Life:** Statutes allow DNR to reduce royalty in specific circumstances on fields nearing the end of their productive, economic lives. However, this relief is difficult to attain. Companies sometimes required to jump through impossible hoops. For example, one Cook Inlet operator was asked to provide detailed cost records back to field discovery. The company couldn't provide those records because it didn't have them. It had purchased the field from another operator. And yet, that was the reason the royalty reduction was declined.
- **Lease Sale Terms:** Existing lease sale program not working. Number of bidders participating in sales is half what it was six years ago. Your old customers aren't coming in the door anymore. They are going where the deals are better, the returns are higher.
- Lease sale bonus bids not major source of revenue for state, especially when compared to severance, royalties. Revenue results from production. State should be doing all it can to encourage evaluation and exploration of its lands.
- Existing law gives DNR authority to vary lease terms, relying less on bonus bids and offering more attractive royalty terms.... net profit share royalties, for example, in place of fixed percentage.
- In fact, we have proposed a net-profit share royalty for State Lease Sale 79 scheduled later this year. We think this approach will increase interest and participation in the lease sale.

- **Smaller Discoveries:** Exploration may yield discoveries which are too small or too marginal during periods of low oil prices to carry the royalty rate under which they were originally leased. DNR has flexibility to reduce royalties in certain circumstances. However, that authority may not extend to new discoveries.

- There should be a means through which the state can help bring these fields on production by reducing the royalty burden. We need a mechanism which allows us to ask for royalty relief and the state to grant it if the state deems action necessary and beneficial.

- **Federal Tax Incentives:** As you saw earlier.... in the UK, Australia, Alaska comparison..... Alaska is the only jurisdiction in which industry is taxed by multiple jurisdictions. There have been some discussions of federal incentives for the oil and gas industry. We would urge you to express your support for those proposals.

- State support of efforts to open ANWR and lift the Export Ban are also necessary.

COMPETITIVENESS

- Finally, we urge you to support and participate in a broad-based process to develop recommendations aimed at enhancing Alaska's international competitiveness.

Slide 9: Next steps

- Making the changes necessary to keep Alaska competitive will not be simple or easy. The initiatives the state undertakes must be chosen carefully, through an open, public, bi-partisan process which involves the legislature, the administration and the industry.

- We must ensure that the steps we take are the right steps. We must understand the competition. We must know and understand what other oil provinces are doing to attract oil industry investment.

- Only then can the administration and the legislature begin to develop options.
- This process will take time. I know that many are eager to act today. But this is far too important a process to hurry along. We must build public consensus if this effort is to succeed.
- I know concern has been expressed that variable or sliding scale royalty rates would adversely impact contributions to the Permanent Fund.
- Again..... I'd ask you to remember that the changes we're asking you to consider are changes designed to turn oil accumulations which are zeroes today --- into jobs, production and additional revenues. Contributions to the Permanent Fund will be higher than they would otherwise be.
- You..... as legislators will decide how to allocate incremental revenues from incremental production.

Slide 10: Conceptual "fixed / variable" royalty

- This slide shows one of the options available to you. The vertical axis is the royalty percentage. Here the royalty percentage increases as a function of oil price, well productivity or field size..... increasing from a low of 6.25 percent ramping up to percentages which would exceed the traditional 12.5 percent.

That's the variable portion of the royalty.

- The shaded area shows the contribution to the Permanent Fund. For this illustration..... we've set the minimum contribution at 6.25 percent, which is the prescribed contribution for production from leases issued since 1979.

As you can see..... the permanent fund contributions could be protected.... and even enhanced if the royalty rate exceeded 12.5 percent because of high oil prices or the discovery of a very large field.

Slide 11: Project partnering

- No matter what the oil price is..... no matter what the state's ultimate tax and royalty regime..... there may be projects on the margin.
- ARCO will look for ways to make these projects happen..... by lowering their cost....developing new technology..... reducing their scope. Those efforts may not always be successful.
- If we can't make a project work on our own ... we may ask you to help us find innovative ways to make the project happen.
- We envision a process in which we explain the project.... in which we explain the economics.... in which we lay our cards on the table. Then it's up to the state to evaluate the data and determine whether the proposal offered is in the state's best interest.
- West Sak might fall into this category.
- We are re-evaluating West Sak at this time. Our goal is to find a way to begin West Sak production at current and expected oil prices. This is a difficult challenge. It will take new technology, and continued reduction in our operating costs. We don't know if we can get there from here.
- If we can't, we may be coming to you with a proposal. We'd like to think the state is willing and able to consider and implement new ideas for making West Sak happen.
- The state can make a difference. State can change the economic equation for marginal oil accumulations in Alaska. I'd like to close this presentation by showing you what can happen..... what did happen in the UK.
- Other areas which might benefit from project partnering are the Lease Sale 79 area, the Western Colville and for fields near

abandonment..... which would not impact ARCO, but might help some Cook Inlet operators.

Slide 12: Capital expenditures UK

- This slide shows capital investment in the UK after the UK began turning zeroes into positive numbers by reducing the tax and royalty burden on new fields...
- The slide shows that \$45 billion has flowed to the UK North Sea for development of new fields. 23 new fields have come on production since 1985. Twelve new fields are scheduled to come on line this year. That's 35 new fields.....

Slide 13: UK North Sea production

- Production from new fields totals more than 1 million barrels a day and accounts for 40 percent of UK North Sea production. UK North Sea production is at record levels.
- The UK changed the economic equation for new, marginal North Sea fields.
- If we work together.....the legislature, the administration and the industry..... we can do it here.