

HB

325

SENATE COMMITTEE REPORT

First Committee of Referral

DATE: 4/2/96

FURTHER: Finance

DATE TURNED INTO OFFICE: 4-22-96

The Resources Committee considered CS FOR HOUSE BILL NO. 325(FIN) am

Relating to modification of royalty to encourage production from an oil pool containing heavy oil; efd.

and recommends:

- be replaced with SCR CS HB325 (YES)
- adopt previous _____ CS _____ (_____)
- attached amendment(s)
- adopt Letter of Intent by _____ Committee
- further referral to the _____ Committee

- Senate Bill:
- same title
 - new title
- House Bill:
- same title
 - technical title
 - new: SCR^e _____

SIGNING DQ PASS	DP	OTHER RECOMMENDATIONS	NR	DNP	AM
<i>Rich Hatfield</i>		<i>[Signature]</i>			<input checked="" type="checkbox"/>
<i>Abner</i>		<i>Chris I. Tap</i>			<input checked="" type="checkbox"/>
<i>[Signature]</i>		<i>[Signature]</i>			<input checked="" type="checkbox"/>
<i>[Signature]</i>					
CHAIR: <i>Steve D. Jensen</i>	<input checked="" type="checkbox"/>	CHAIR:			

NEW FISCAL NOTE(S):

Department	Date	Zero	Fiscal

PREVIOUS FISCAL NOTE(S):*

Department	Date	Zero	Fiscal
Revenue	3/1/96	<input checked="" type="checkbox"/>	
INT. OIG	4/2/96		(2200)

*PN 40
C. 1102*

APPROPRIATION -- no fiscal note

*include fiscal notes accompanying Governor's bill

SENATE CS FOR CS FOR HOUSE BILL NO. 325(RES)
 IN THE LEGISLATURE OF THE STATE OF ALASKA
 NINETEENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
 Referred:

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to modification of royalty to encourage production from an
 2 oil pool containing heavy oil; and providing for an effective date."

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

4 * Section 1. AS 38.05.180 is amended by adding a new subsection to read:

5 (dd) Notwithstanding any other provision of this section or any provision in
 6 a lease, unit agreement, or other agreement between a lessee and the state that
 7 establishes an obligation to pay royalty on production, royalty is payable at a rate of
 8 two percent, under the conditions and to the extent described in this subsection, for the
 9 production of heavy oil that is removed or sold from a lease or leases located north
 10 of the Umiat baseline, as follows:

11 (1) under this subsection, the reduction in payment of royalty applies

12 (A) only to the portion of the lessee's reported royalty, as may
 13 be later adjusted, before any field cost deduction, as calculated for the month of
 14 production, for the first 450 barrels of daily production of heavy oil from the

1 well, the royalty value of which does not exceed \$15 per barrel as estimated at
2 the lease automatic custody transfer meter at which custody is first transferred
3 into a common carrier pipeline;

4 (B) only if the initial drilling of the well from which the heavy
5 oil is produced began on or after July 1, 1996, and before July 1, 2006; for
6 purposes of this subparagraph, "initial drilling" does not include plug-backs of
7 existing wells, sidetracks from existing wells, multi-lateral or dual completions
8 of existing wells, or sidetracks of redrilled wells;

9 (C) only to heavy oil produced during the first 1,825 days of well
10 operation after the initial production of oil from the well, as reported to the
11 Alaska Oil and Gas Conservation Commission; for purposes of this
12 subparagraph, "initial production" means production following initial drilling;

13 (D) for a well only if the lessee

14 (i) submits with its royalty report for the first month for
15 which the reduction in royalty payment under (A) - (C) of this paragraph
16 is claimed and with subsequent royalty reports for so long as the
17 reduction continues, oil gravity test results performed during the period
18 for which the royalty report is filed demonstrating that the oil tested is
19 heavy oil; the oil gravity test must be in accordance with the standards
20 for measurement and testing set out in the regulations of the Alaska Oil
21 and Gas Conservation Commission; the oil gravity test must be conducted
22 at quarterly intervals except that, for oil that, when tested, has a weighted
23 average of 19 degrees API gravity or greater, the oil gravity test must be
24 conducted not less often than monthly; and

25 (ii) maintains, for a period of at least six years after the
26 last day of the royalty payment reduction authorized by this subsection,
27 records of production that show the actual date that drilling of the well
28 started, the daily production from the well, and the API degree gravity
29 data, and allows the department to inspect the records during regular
30 business hours; and

31 (E) only if the deepest producing perforation of the well from
32 which heavy oil is produced is shallower than 5,000 feet;

1 (2) by taking a reduction in the payment of royalty under this
2 subsection, the lessee waives any right that the lessee might otherwise have under its
3 lease, unit agreement, or other agreement with the state to deduct, against royalty due
4 the state, any field costs associated with the production of the heavy oil for which the
5 reduction is taken;

6 (3) when a reduction in payment of royalty is obtained on the
7 production of heavy oil under this subsection, for a period of 20 years after the last
8 day on which a royalty payment reduction is taken under this subsection, the lessee
9 may not apply for further adjustment of royalty, whether through contract or a
10 provision of law authorizing a royalty modification, on the production of oil from the
11 well for which a reduced royalty was taken under this subsection;

12 (4) for purposes of calculating the first 450 barrels per day of daily
13 production of heavy oil from a well, the production from dual completions and other
14 forms of multiple completions in a well is to be added together and counted as
15 production from a single well;

16 (5) in this subsection,

17 (A) "field costs" includes the lease or unit expenses identified
18 in (f) of this section;

19 (B) "heavy oil" means oil having a weighted average equal to
20 or less than 20 degrees API gravity as the term "API gravity" is defined in
21 AS 43.55.900.

22 • Sec. 2. This Act takes effect immediately under AS 01.10.070(c)



Alaska State Legislature


Senate Resources Committee

Official Business

State Capitol
Juneau AK 99801

MEMO

TO: Legal Services
via fax: X2029 this page only

FROM: Annette Kreitzer, Aide to 
Senate Resources Committee

DATE: April 22, 1996

RE: CS HB 325 : North Slope Heavy Oil Royalty Modification

Please draft a FINAL Resources committee substitute for HB 325 using 9-LS1122Z with the following amendments:

- 1) Page 2, Line 1 following well
INSERT: well, [THAT] the royalty value of which does not exceed \$15 per barrel with value estimated at the Lease Automatic Custody Transfer meter(s) where custody is first transferred into a common carrier pipeline.

9-LS1122VZ
Chenoweth
4/21/96

SENATE CS FOR CS FOR HOUSE BILL NO. 325(RES)
IN THE LEGISLATURE OF THE STATE OF ALASKA
NINETEENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): REPRESENTATIVE GREEN

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8 two percent, under the conditions and to the extent described in this subsection, for the
9 production of heavy oil that is removed or sold from a lease or leases located north
10 of the Umiat baseline, as follows:

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12 (A) only to the portion of the lessee's reported royalty, as may
13 be later adjusted, before any field cost deduction, as calculated for the month of
14 production, for the first 450 barrels of daily production of heavy oil from the

1 well that does not exceed \$15 per barrel:

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3 oil is produced began on or after July 1, 1996, and before July 1, 2006; for
4 purposes of this subparagraph, "initial drilling" does not include plug-backs of
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27 data, and allows the department to inspect the records during regular
28 business hours; and

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30 which heavy oil is produced is shallower than 5,000 feet;

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32 subsection, the lessee waives any right that the lessee might otherwise have under its

1 lease, unit agreement, or other agreement with the state to deduct, against royalty due
2 the state, any field costs associated with the production of the heavy oil for which the
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Alaska State Legislature


Senate Resources Committee

Official Business

State Capitol
Juneau AK 99801

MEMO

TO: Legal Services
via fax: X2029 this page only

FROM: Annette Kreitzer, Aide to 
Senate Resources Committee

DATE: April 20, 1996

RE: CS HB 325 : North Slope Heavy Oil Royalty Modification

Please draft a Resources committee substitute for HB 325 using 9-LS1122U (HB0325d) with the following amendments:

- 1) Page 2, Line 3:
DELETE:
[ACTUAL]
- 2) Page 2, Line 22:
DELETE:
[TWO]
Insert:
six
- 3) Page 2, Lines 28-29:
DELETE ALL MATERIAL
Insert:
(E) only if the deepest producing perforation of the well from which the heavy oil is produced is shallower than 5,000 feet.
- 4) Page 3, Lines 3-7:
DELETE ALL MATERIAL
Insert:
(3) when a reduction in payment of royalty is obtained on the production of heavy oil under this subsection, for a period of 20 years after the last day on which a royalty payment reduction is taken under this subsection, the lessee may not apply for any further adjustment of royalty, whether through contract or any provision of law authorizing a royalty modification, on the production of oil from the well for which a reduced royalty was taken under this subsection.
- 5) Page 3, Line 8:
DELETE:
[500]
Insert:
450



Alaska State Legislature

NOTE TO REPRESENTATIVE GREEN (Jeff Logan); and to KEN BOYD:
These are the amendments proposed for HB 325. Please look over and let
me know if you have further suggestions, comments or if you disagree with
Official these amendments. AK (X4907) Juneau AK 99801

MEMO

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via fax: X2029 this page only

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DATE: April 20, 1996

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Insert:
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production of heavy oil under this subsection, for a period of 20 years after the last day on
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authorizing a royalty modification, on the production of oil from the well for which a
reduced royalty was taken under this subsection.
- 5) Page 3, Line 8:
DELETE:
[500]
Insert:
450

- END -

Conclusion

*Top Revenue
20 million
via 2007
100 million*

1) Page 1, line 15 set the \$15 per barrel level as the point below which heavy oil will qualify for reduced royalty. At what point is it intended that the \$15 price be measured?

in 100% market when 100% of the oil is produced

2) Page 2, line 22—why was a two year period selected for production records retention rather than using the same period for which the state has audit rights for taxes and royalties?

3) Page 3, line 8—the 500 barrel limit needs to be changed to 450, as amended on the House floor.

Page 3, line 9—provides that, for the purposes of calculating the volume of oil to which royalty reduction applies in wells with dual compilations, production is to be added together. What happens if oil with a higher gravity is blended with lower gravity oil to produce a blend that is higher gravity than the low gravity oil, but lower than the 20 degrees API cut-off under the bill?

*100%
100%*

*100%
100%*

*100%
100%*

*100%
100%*

*100%
100%*

Proposed Amendment to CSIB 325(FIN) am

Amend P. 3, ls. 3-7 as follows:

(3) when a reduction in payment of royalty is obtained on the production of heavy oil under this subsection, for a period of 20 years after the last day on which a royalty payment reduction is taken [ALLOWED] under this subsection, the lessee may not [CLAIM OR OBTAIN THE BENEFIT OF AN] apply for any further adjustment of royalty, whether through contract or any provision of law authorizing a royalty modification, on the production of heavy oil from the well for which a reduced royalty was taken under this subsection [UNDER CONTRACT OR ANY OTHER PROVISION OF LAW AUTHORIZING A ROYALTY MODIFICATION]

Corporate

578-2559

Rationale for Proposed Amendment to CS HB 325(FIN) am

In the House Finance Committee, HB 325 was amended to ensure that, if a lessee claimed the legislation's five-year incentive for a new heavy oil well, it could not, after those five years, seek an additional royalty reduction on continued heavy oil production from that well. The prohibition would last 20 years.

HB 325 benefits the state because, in return for materially improving project economics through a five-year reduced royalty, the state would receive full royalties—at either 12.5% or 20%—over the remainder of the projected 40-year field life of the development. The Finance Committee amendment was aimed at assuring that those full royalties were actually received after the five-year incentive period ended.

Unfortunately, by barring a lessee from claiming any reduced royalty on the "production of oil" for 20 years, the Finance Committee seems to have prohibited any reduced royalty for *any oil production* in Alaska, and not just the heavy oil for which the incentive was taken. The proposed amendment confines the prohibition to its intended reach.

Replace the language on p. 2, ls 28-29 with the following language:

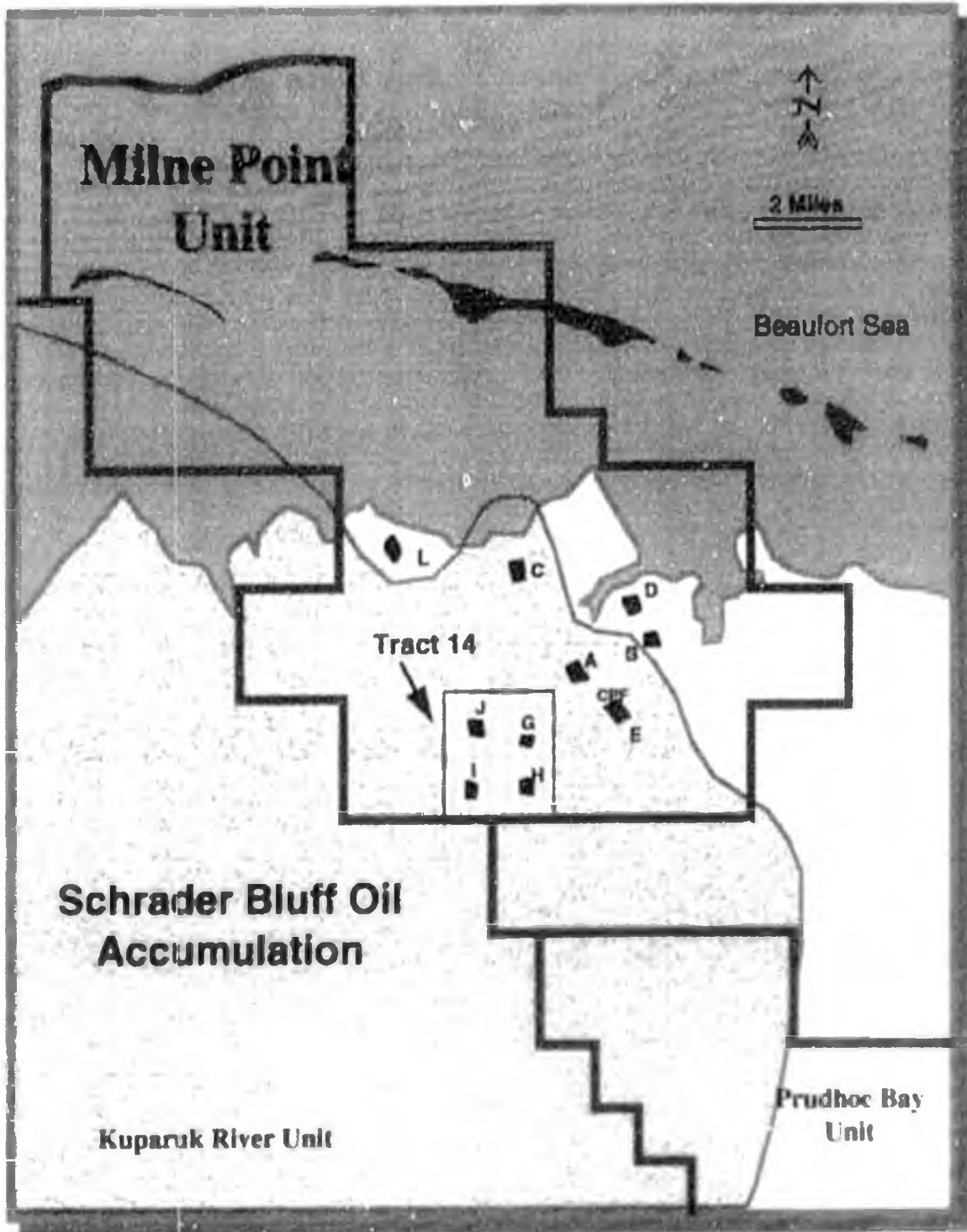
(E) only if the deepest producing perforation of the well from which the heavy oil is produced is shallower than 5,000 feet;

OXY USA Inc.

Presentation to the Senate Resources Committee on

CSHB 325(FIN) am

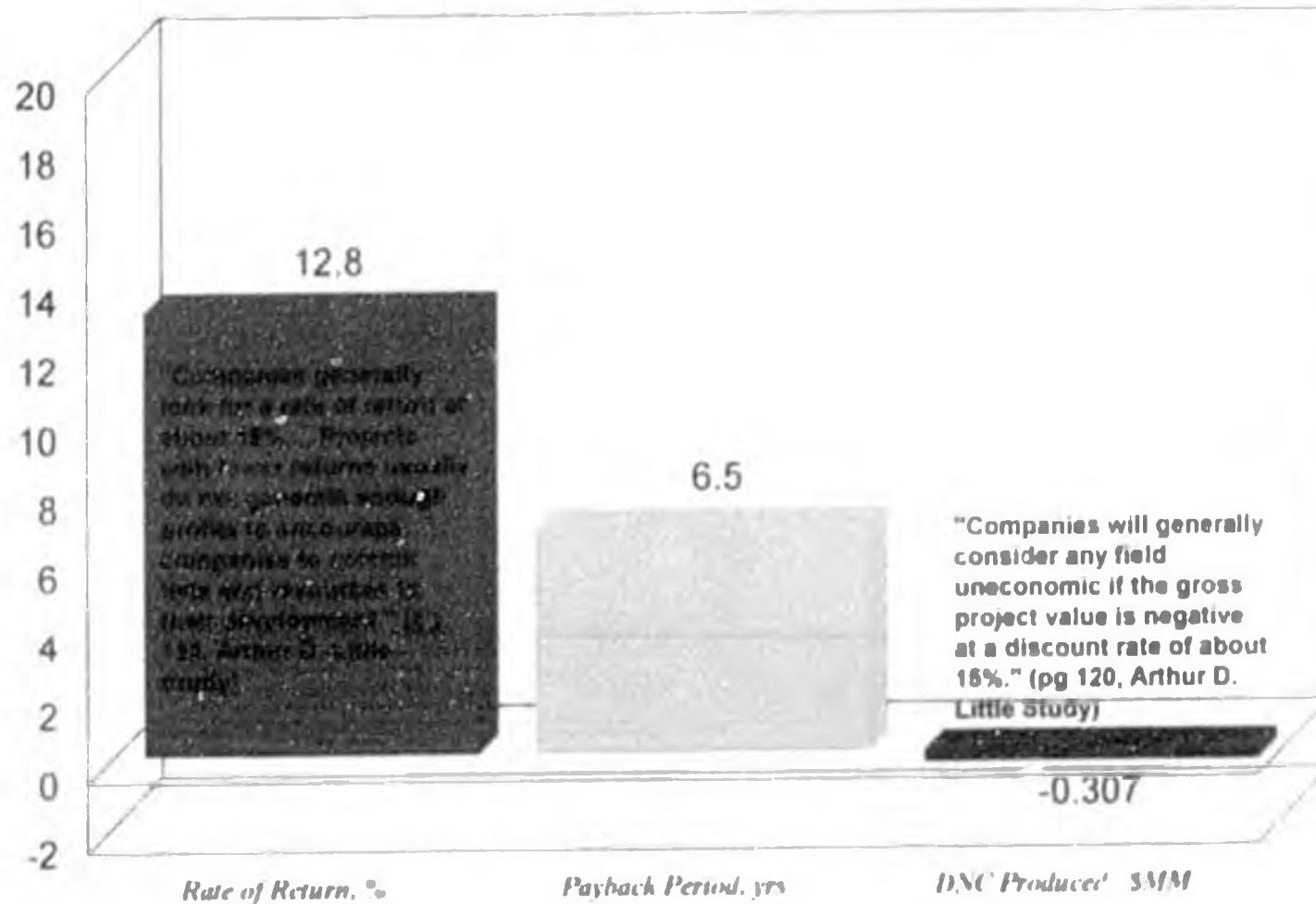
April 17, 1996



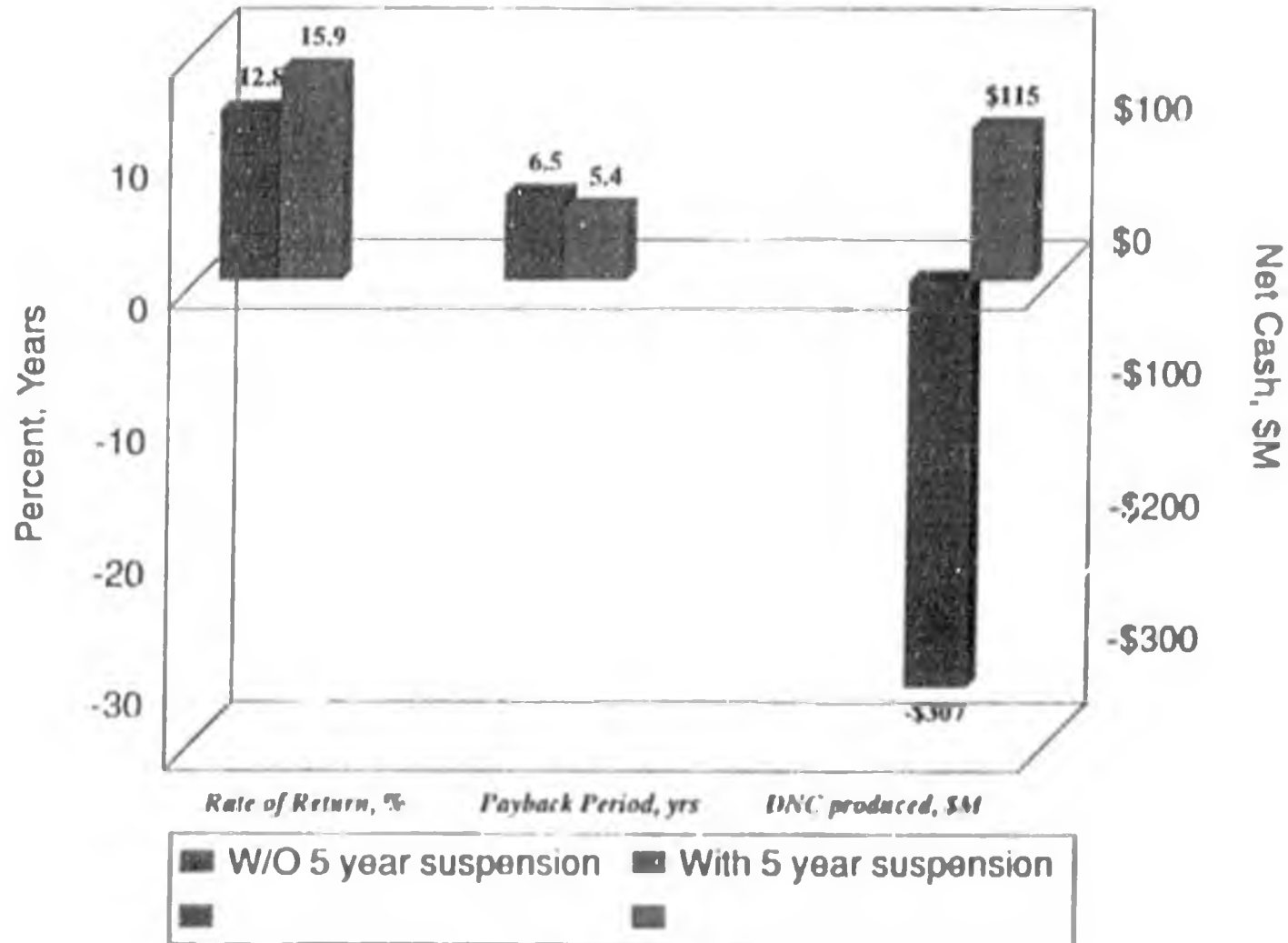
Schrader Bluff Oil Accumulation

Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14



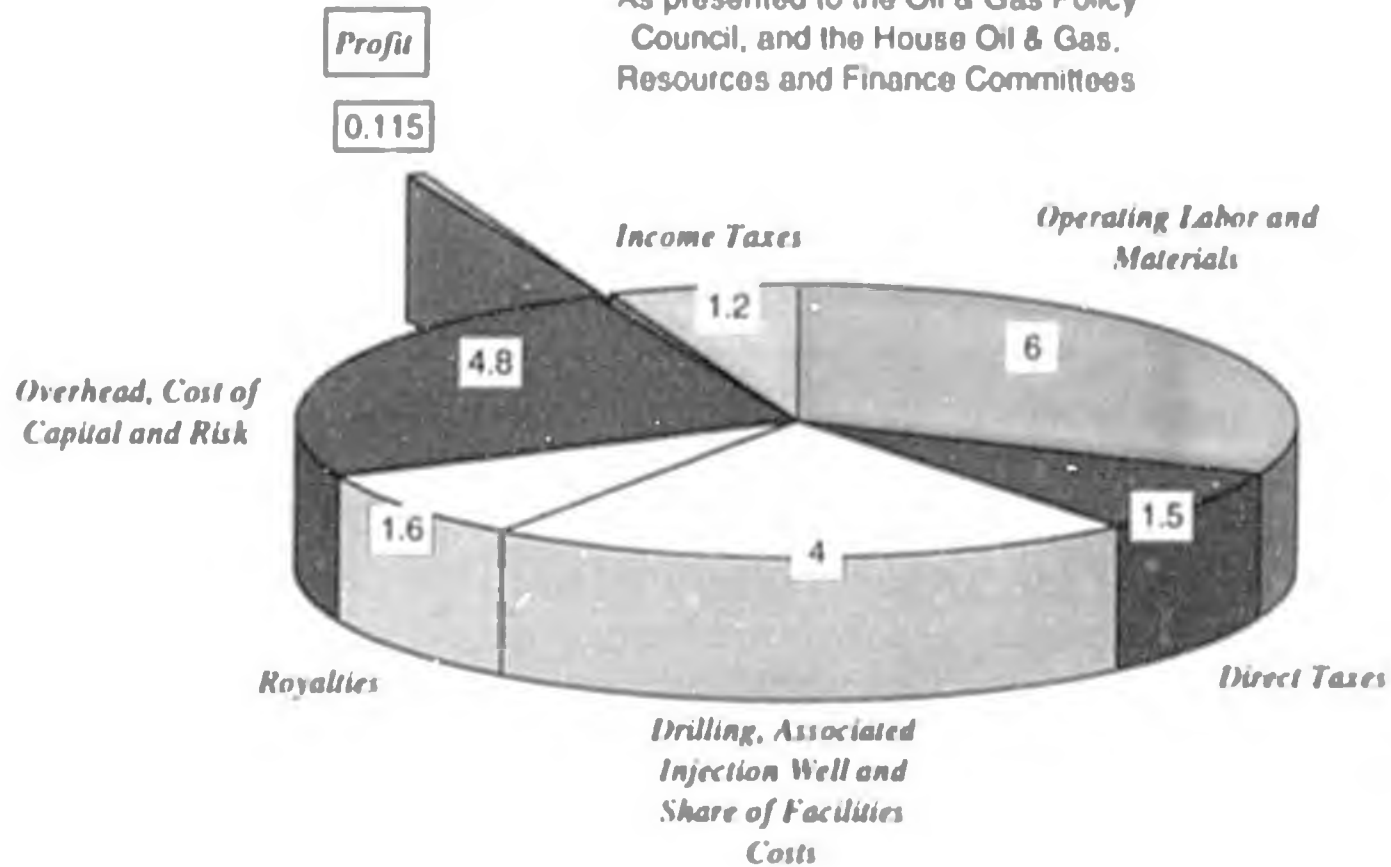
The Effect of Royalty Suspension on Schrader Bluff Economics



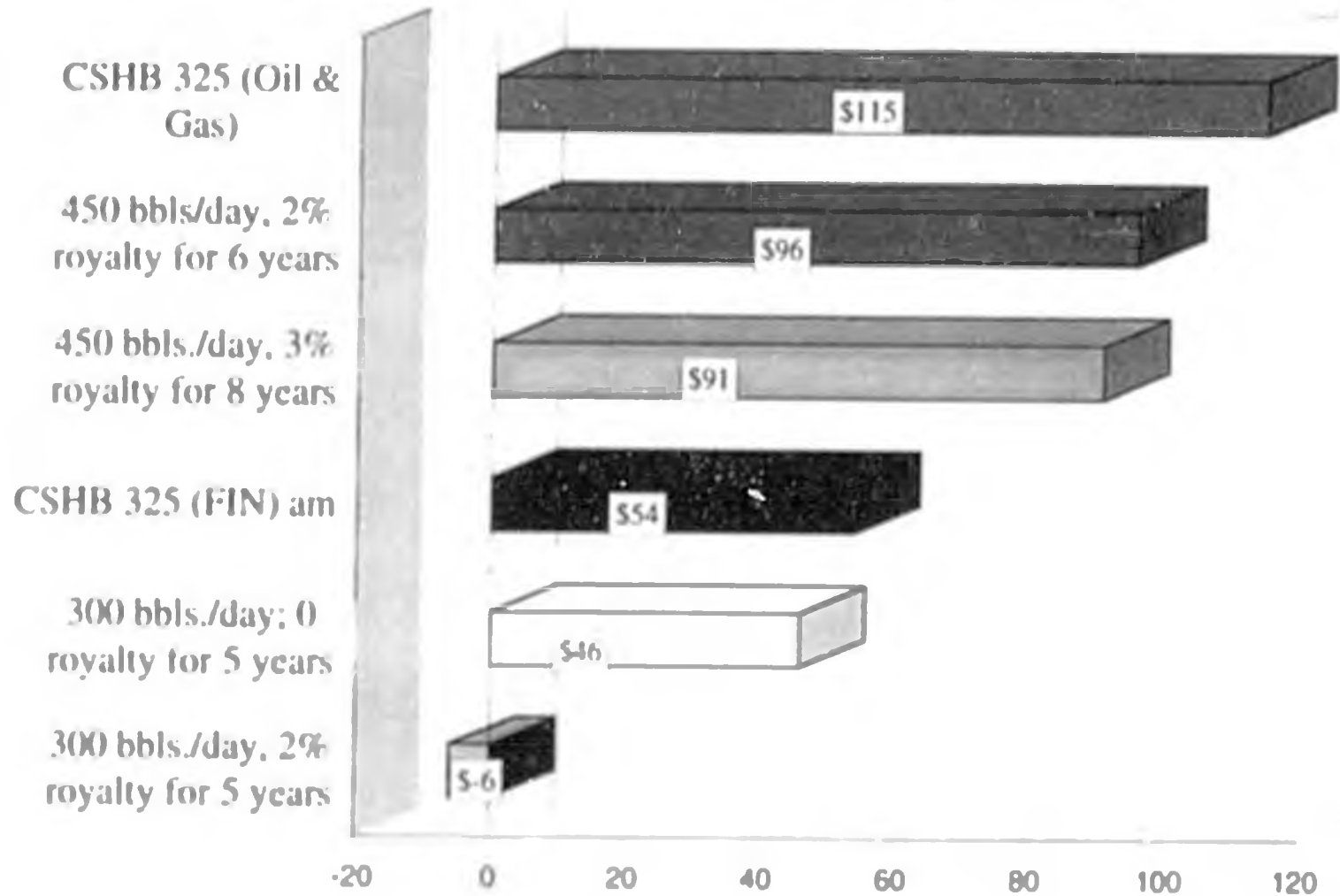
Where the Revenues from Heavy Oil Development Go

OXY Per Well Economics (in millions)

As presented to the Oil & Gas Policy Council, and the House Oil & Gas Resources and Finance Committees

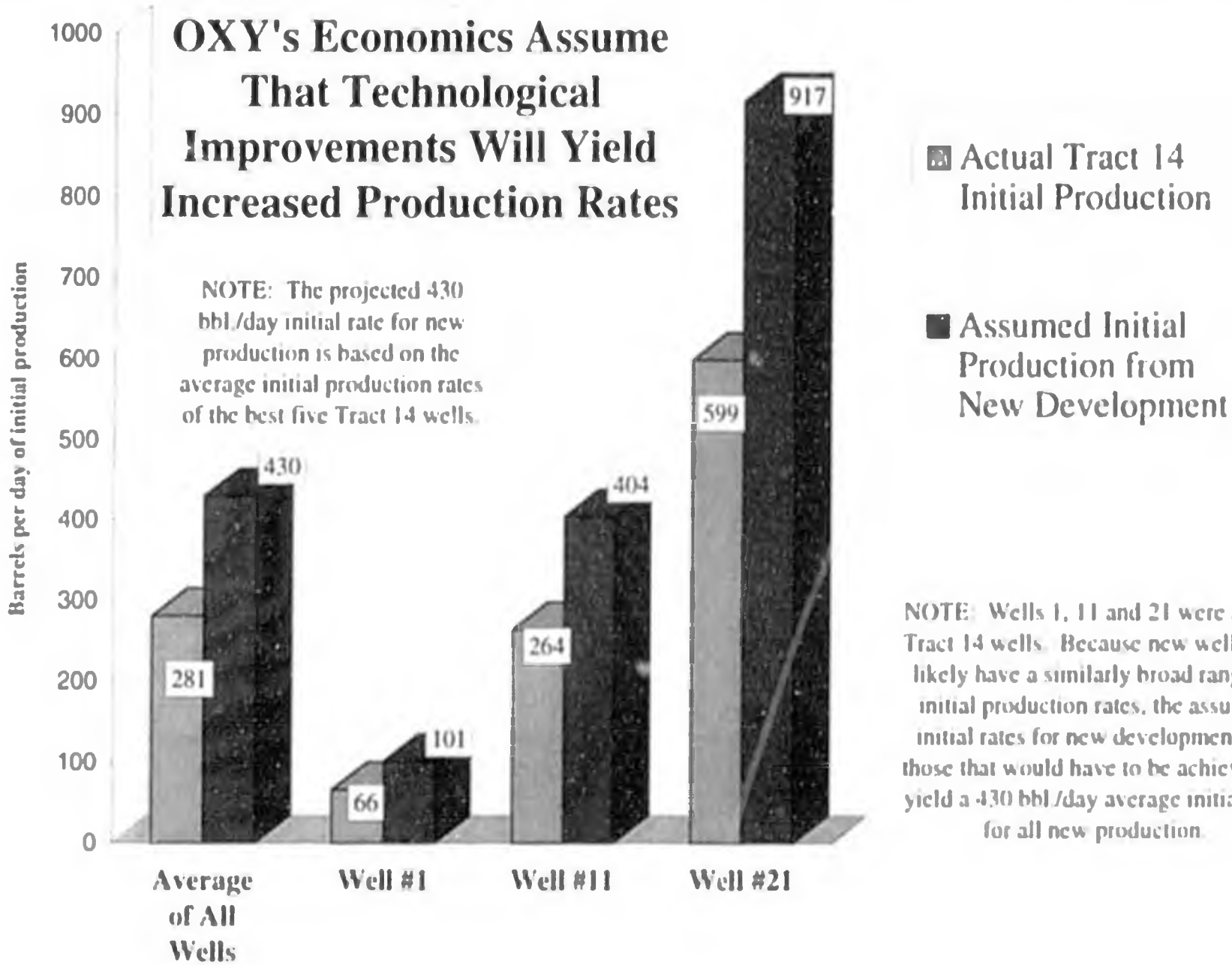


Projected Profit from Each \$4 Million Well and Facility Investment Under Various Scenarios



In thousands of dollars @ a 15% discount

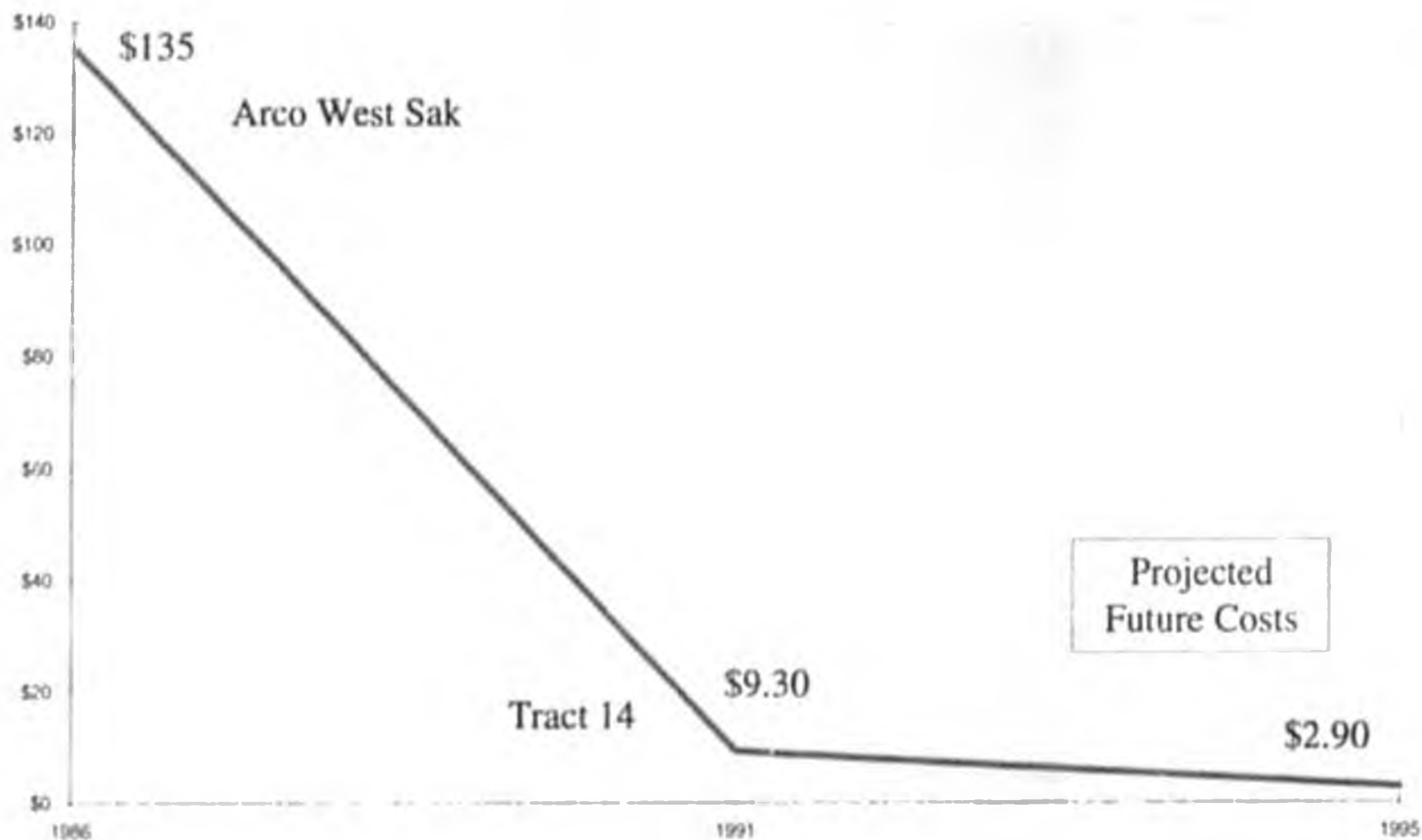
OXY's Economics Assume That Technological Improvements Will Yield Increased Production Rates



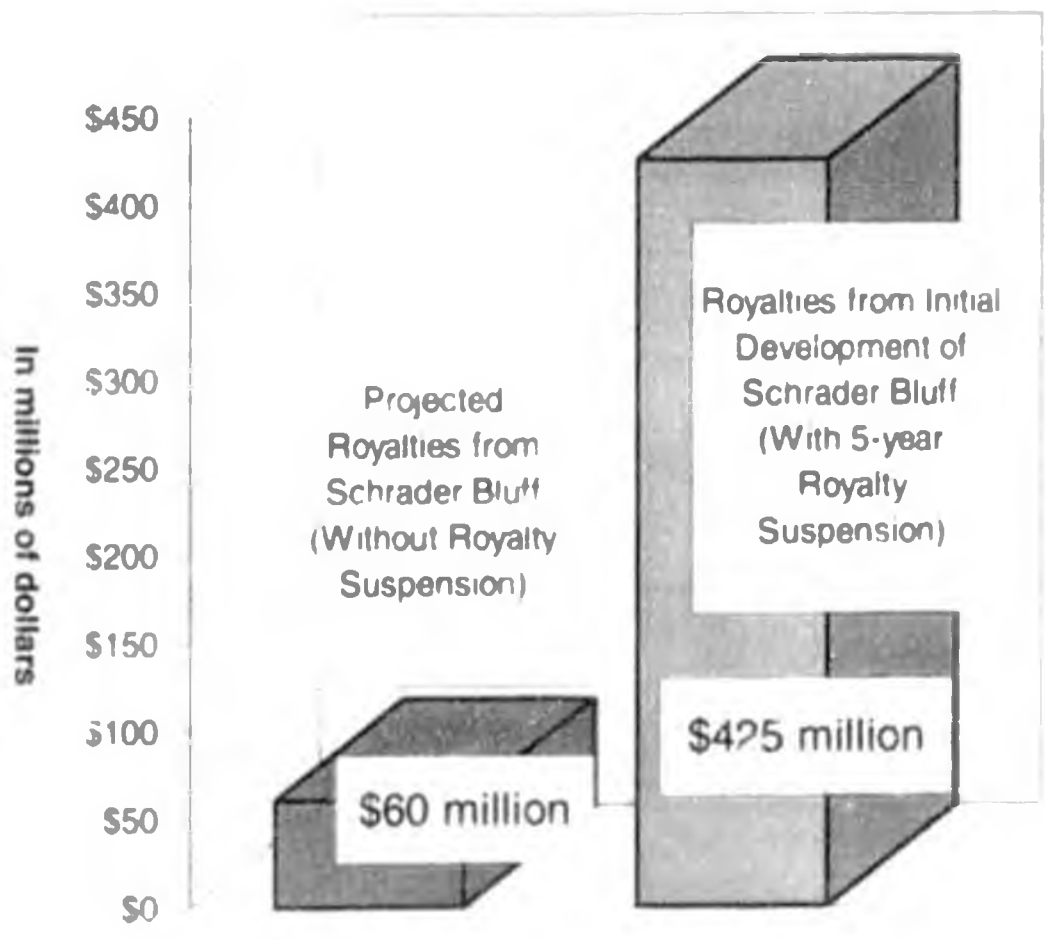
NOTE: Wells 1, 11 and 21 were actual Tract 14 wells. Because new wells will likely have a similarly broad range of initial production rates, the assumed initial rates for new development are those that would have to be achieved to yield a 430 bbl/day average initial rate for all new production.

History of ANS Heavy Oil Development Costs

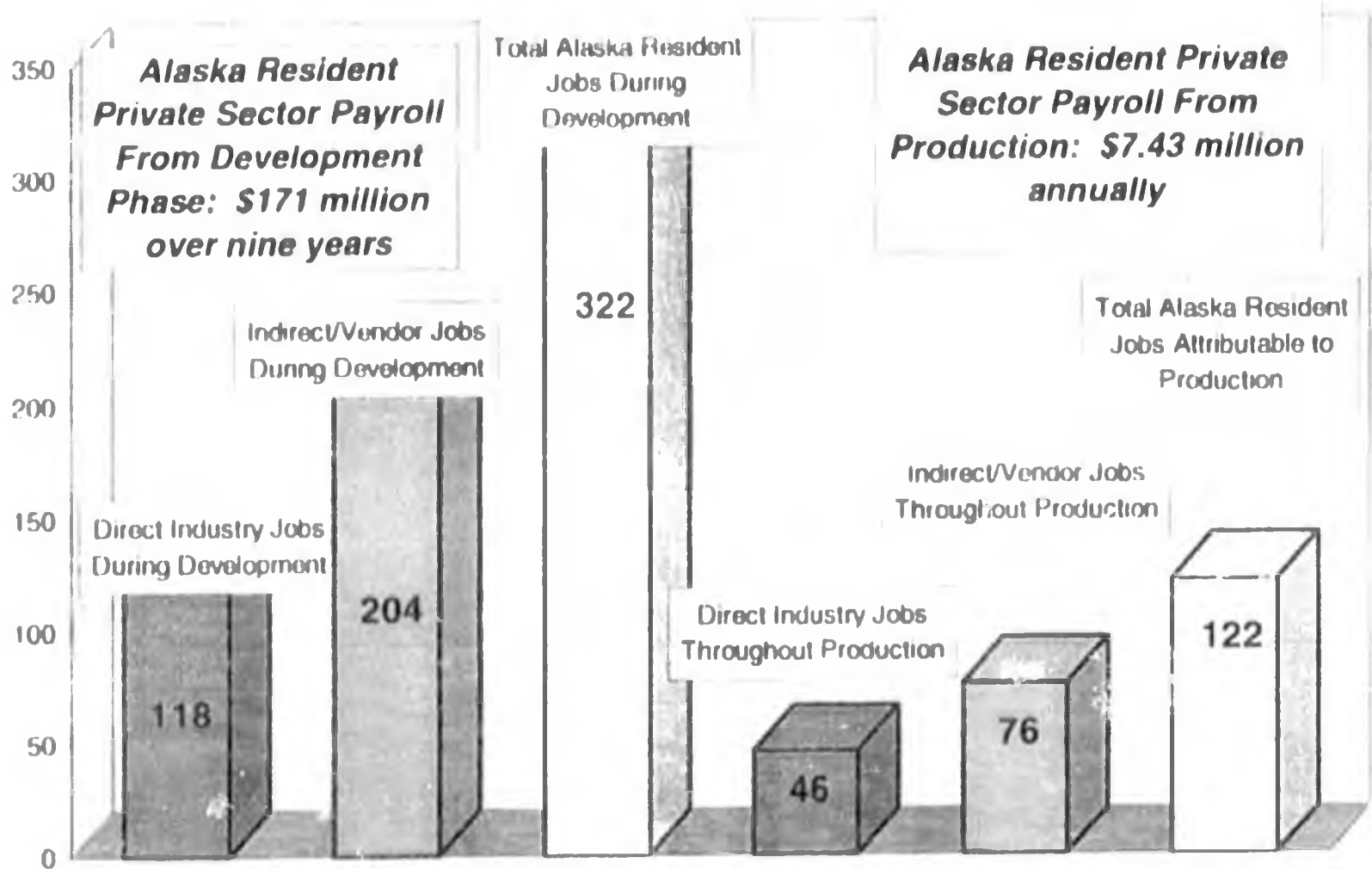
In dollars per barrel



Two Paths for Schrader Bluff



Alaska Resident Private-Sector Jobs Created by Schrader Bluff Development



APR 19 1996

ATTORNEYS AT LAW
SIMPSON, TILLINGHAST, SORENSEN & LORENSEN
A PROFESSIONAL CORPORATION

LESLIE LONGENBAUGH
RONALD W. LORENSEN
L. MERRILL LOWDEN
E. BUDD SIMPSON
STEPHEN F. SORENSEN
JON K. TILLINGHAST

ONE SEALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801
PHONE (907) 586-1400
FAX (907) 586-3065

April 19, 1996

The Honorable Loren Leman
Alaska State Senate
State of Alaska
Senate Resources Committee
Capitol Building, Room 113
Juneau, Alaska 99801

Re CSHB 325(FIN) am

Dear Senator Leman

During House debates on HB 325 (relating to heavy oil), OXY USA Inc. was asked why the discretionary relief process established in HB 207 last session was not adequate to encourage development of Alaska's heavy oil reserves. In response, OXY submitted the enclosed letter, which we're offering for your consideration in connection with Senate Resources Committee deliberations on the legislation.

Thank you in advance for your time spent reviewing the enclosed correspondence.

Sincerely,

SIMPSON, TILLINGHAST,
SORENSEN & LORENSEN



Jonathan K. Tillinghast

Enclosure

ATTORNEYS AT LAW
SIMPSON, TILLINGHAST, SORENSEN & LORENSEN
A PROFESSIONAL CORPORATION

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ION K. TILLINGHAST

ONE ALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801
PHONE (907) 586-1400
FAX (907) 586-3065

February 2, 1996

The Honorable Joe Green
Alaska State House of Representatives
State Capitol, Room 24
Juneau, Alaska 99801-1182

Re: Application of HB 207 to Heavy Oil
Our File No. 8402

Dear Representative Green

OXY USA Inc ("OXY") has asked us to respond to Division of Oil and Gas Director Kenneth Boyd's January 30, 1996 letter to Representative Bill Williams regarding the possible use of HB 207 to accomplish the goals of HB 325. In summary, we are confident that HB 207, as it currently exists, cannot be used to fashion an effective ANS heavy oil incentive. To cure the problems associated with HB 207, as it applies to ANS heavy oil, we believe that last year's law would need to be amended to substitute the process and substance of HB 325 for the discretionary procedures set out in HB 207.

To begin with, OXY very much agrees with Mr. Boyd that HB 325 furthers the "primary purpose" of HB 207. OXY, in fact, entered the debate over heavy oil only in response to Governor Knowles' invitation to the private sector to explore new partnerships to develop Alaska's untapped energy resources.

However, HB 207 was never intended as the sole, nor even the principal vehicle for accomplishing that goal. Before each of the several legislative committees that considered HB 207 last session, DNR Commissioner John Shively stressed that HB 207 was only a tentative beginning, and that more concrete initiatives would follow. As Commissioner Shively explained to the Senate Resources Committee:

There are a variety of ideas about how to provide the oil industry with the incentive to develop marginal oil fields.

HB 207 was a compromise effort that can be implemented this year, as opposed to other ideas that can be studied by the Governor's Oil and Gas Policy Commission (sic).

Minutes, Senate Resources Committee, April 22, 1995 at 8. Commissioner Shively made the same point to your committee:

[Shively] said the Administration believes there are a number of things which can be done, both in the state's best interest and in the oil industry's best interest, to help encourage greater oil development. He noted part of that may be done now but the bulk of that will be done through the study the Governor's Oil and Gas Policy Council will be conducting over the next several years.

Minutes, House Resources Committee, March 32, 1995 at 3, emphasis added. As Commissioner Shively explained to the House Oil and Gas Committee, HB 207 was simply a quick first step from a new administration

[Shively] said, he thinks there are other roads, and some other additional legislation. He stated it was his decision, at this point, given the newness of the Administration, that this is something we can do this year. However, the Governor has appointed the Oil and Gas Policy Council, and one of their responsibilities is to look at other methods of providing incentives for oil development, and for a healthy oil industry. He then stated they consider this to be just the first step.

Minutes, House Oil and Gas Committee, March 9, 1995 at 4

Heavy oil, in particular, was excluded from the HB 207 debate. Last April, OXY sought the advice of both the administration, and the legislature, on the most appropriate vehicle for addressing heavy oil incentives. At the time, both felt that HB 207 was the wrong vehicle for that endeavor, and that the heavy oil issue should instead be treated

Similarly, Commissioner Shively told the Senate Finance Committee that

A number of ideas have been proposed to provide incentives for development of marginal fields in Alaska. Early in this administration, the proposed royalty incentive was determined to be something we could do this year while the oil and gas policy commission (sic) examines other methods of making the state more competitive, internationally.

Minutes, Senate Finance Committee, May 8, 1995

separately, over the interim, through the Oil and Gas Policy Council and the appropriate legislative committees

OXY appreciates the administration's interest in encouraging heavy oil development, through HB 207 or any other means. That interest re-enforces DNR's long-held view that, under the existing fiscal environment, heavy oil development isn't likely to occur.^{2/} The effort, unfortunately, is procrustean.^{3/} The goals of HB 325 can't be forced into HB 207's structure for six reasons:

1. Schrader Bluff is ineligible under HB 207

Mr. Boyd is correct that HB 207 does not authorize royalty relief in all circumstances, but rather under only three tightly-defined conditions. Mr. Boyd argues that the second of those circumstances--the "Declining Field" circumstance set out in AS 38 05 130(j)(1)(B)--might be made to fit Schrader Bluff.^{4/}

The "Declining Field" clause in HB 207 was intended to apply to older fields that are reaching their economic limit because production is declining, and per-barrel costs are correspondingly rising. It is, in short, the Cook Inlet clause, and was never intended to apply to stimulate initial development of new fields that had experienced only pilot drilling.

The limitations of that clause, and its inapplicability to Schrader Bluff, are apparent from three different angles

a. The language of the clause. By its terms, the clause allows royalty relief only: (1) to "prolong the life" of an oil field, and (2) "as costs per barrel increase"

The purpose of HB 325 is not to "prolong" Schrader Bluff's field life, for at the moment (and save for a pilot project) there is nothing to prolong. HB 325's purpose, rather, is to encourage *initial development* of an essentially untapped field.^{5/}

As our white paper, *An Opportunity to Develop Alaska's Heavy Oil Resources*, explains, DNR's Spring, 1994 production forecasts concluded that the entire Milne Point Unit (inclusive of Schrader Bluff) would be abandoned in 2006, while that agency's Spring, 1995 forecasts predicted unit abandonment in 2011. Neither forecast assumed any heavy oil development, save for the minor production flowing from the Tract 14 pilot project. Some projected heavy oil development first appeared in the Department of Revenue's Fall, 1995 forecasts because of methodology changes that were unrelated to the actual likelihood of Schrader Bluff development.

Procrustes, you'll recall, was the villainous son of Poseidon who forced travelers to fit into his wooden bed by stretching them on a rack, or cutting off their limbs.

Mr. Boyd briefly argues that the third circumstance--where royalty relief may be granted to "reestablish production of shut-in oil"--might also be availing. There is no shut-in production at Schrader Bluff, and, through the Tract 14 pilot wells, the field produces and sells 3,000 bbls/day.

Indeed, one would think that, if any of HB 207's three bases for royalty relief were applicable to Schrader Bluff, it would be what Mr. Boyd calls the "New Pool" clause of AS 38 05 130(j)(1)(A). However, Mr. Boyd concedes that this basis is unavailable because it excludes

Moreover, "costs per barrel" are not increasing at Schrader Bluff, as they are in Cook Inlet where constant operating expenses are being spread over fewer and fewer barrels. To the contrary, one essential goal of BP's and OXY's pilot efforts has been to reduce per barrel costs, and, as BP has testified before your committee, continued *decreases* in per barrel costs are as essential to field development as is an effective legislative incentive.

b. HB 207's legislative history. Commissioner Shively explained to the Senate Finance Committee that the "Declining Field" clause was only intended to cover "fields that are declining or about to be shut in."⁶¹ The clause, the Commissioner added, addressed only fields "that might be abandoned" (*id.*), and DNR's position paper on HB 207 made it clear that the clause was aimed only at providing relief at the end of a field's life. The clause, the agency said, covered:

Oil and gas fields whose economic life may be prolonged in light of increasing costs in the later stages of production.

"CS for HB 207 (FIN) AM QUESTIONS AND ANSWERS," (hereinafter "DNR Paper") undated at 1; emphasis added. These were what the agency called "mature producing fields,"⁶² or what Chair Rokeburg more directly described as "old uneconomic fields...e.g. Cook Inlet."⁶³

The administration and the legislature knew what the "Declining Field" clause encompassed. The clause was directed at Cook Inlet fields, and not initial development of ANS heavy oil.

c. Prior DNR precedent. HB 207 added only one category of fields eligible for royalty relief--Mr. Boyd's "New Pools," the most frequently cited example being the Badami field. As DNR consistently reminded the legislature, the Declining Field clause pre-dated HB 207.

The current law allows the commissioner to grant royalty reduction to prolong the economic life of a field or to reestablish shut-in production.

any field that has "previously produced oil or gas for sale." The statute thus fails to account for new fields from which some production has occurred from test or pilot drilling. Whether that omission was intentional or inadvertent, it's still nonetheless fatal to Schrader Bluff's eligibility under HB 207.

⁶¹ Minutes, Senate Finance Committee, May 8, 1995.

⁶² *Id.* at 3.

⁶³ Memorandum, Chair Rokeburg to Members of Senate Finance Committee, May 5, 1995 at 2.

DNR Paper at 1, emphasis added. Indeed, DNR often cited its pre-existing authority under the Declining Field clause as a defense to claims that HB 207 gave the agency excessive discretion. Granting royalty relief under the Declining Field clause, Commissioner Shively told the House Oil and Gas Committee, "is really not something new to the office."⁹ Indeed, and as Mr. Boyd explained to the Senate Finance Committee, the Conoco/OXY royalty relief application had been decided under that clause.¹⁰

The Conoco decision, in which Conoco and OXY were denied any adjustment to the special royalty surcharge imposed on some Milne Point production at the time the Milne Point Unit was formed, concluded that relief could not be granted under the Declining Field clause until near the very end of field life. Until then, any prognosis about field economics would be dependent on projections of future oil prices, and the inherent uncertainties in forecasting the future price of oil made it *impossible* for Conoco to make the requisite "clear" showing of entitlement to relief. Said the hearing officer

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 [under the Declining Field clause] at this time.

*It is very difficult, if not impossible, to provide such [clear] evidence here, since the Milne Point field is in the very early stages of production.*¹¹

The Declining Field clause, DNR ruled, was available only to Cook Inlet fields, where but a few production years remained. Younger fields were ineligible. And given that

(1) the Declining Field clause, according to DNR, was simply transferred into HB 207

⁹ Minutes, House Oil and Gas Committee, March 9, 1995 at 4.

¹⁰ Minutes, Senate Finance Committee, May 8, 1995.

¹¹ 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) (hereinafter "Conoco Decision"), December 28, 1990 at 15-16.

(2) the former standard of requiring a "clear" showing was replaced in HB 207 by an even more stringent "clear and convincing showing" requirement;¹² and

(3) Schrader Bluff's potential 41-year field life is nearly twice as long as the Kuparuk Formation field life at issue in the Conoco decision.

Mr. Boyd's suggestion that the future development of ANS heavy oil be adjudicated under the Declining Field clause does not give ground for optimism.

II. HB 207 Does Not Allow Royalty Suspensions

Mr. Boyd has suggested an amendment to HB 207 that might obviate Schrader Bluff's eligibility problem. However, amending HB 207's eligibility requirements would not lessen any of the other difficulties inherent in relying on that statute.

The first of these other problems is HB 207's mandatory 3% royalty floor for Declining Fields. AS 38 05 180(j)(4)(B).

As our white paper explains (*see n. 2, ante*), heavy oil fields are materially different from the kinds of fields considered in the debate over HB 207. Their initial production rates are low; however, production then declines quite gradually thereafter, and the field enjoys a remarkably long life--in Schrader Bluff's case, an estimated 41-years.

Thus, and as the white paper demonstrates, the State of Alaska would likely earn considerably more royalty income from a five-year royalty suspension at the outset of production (which is what HB 325 envisions) than from a reduced royalty spread over the life of the field (as HB 207 envisions).

Indeed, the white paper estimates that the State of Alaska *would lose about \$800,000 per well* if it imposed a 5% field royalty under HB 207 rather than enacting HB 325. *Id.* at 39, Chart 16.

As the white paper also discusses, Arthur D. Little, in its report to the Oil and Gas Policy Council, faulted Alaska for insisting on a one-size-fits-all royalty policy that is insensitive to the peculiarities of particular marginal fields. HB 207's royalty floor may make sense as a general proposition, but it disserves both the public's and industry's interest in developing heavy oil. In this respect, then, HB 207 proves Arthur D. Little's point, and it also underscores the wisdom of Commissioner Shively's repeated cautions to the legislature that HB 207 was never intended to address every oil and gas incentive issue.

¹² AS 38 05 180(j)(2)

III. HB 207 Addresses Only Lease-Based Royalty Relief

HB 207 only authorizes royalty relief for leases and unitized interests. AS 38.05.180(j)(1). It does not envision royalty relief targeted to individual wells that may be owned by several lessees.

HB 325, conversely, purposefully targets only individual new heavy oil wells. In so doing, it denies any incentive to production from pre-existing heavy oil wells, or production from other oil-bearing formations in the unit. In this way, it ensures that incentives are offered only when they serve the bill's primary purpose--to encourage new heavy oil drilling.

Also, HB 325's five-year suspension limit applies on a per well basis, so that the state can begin receiving royalties early in the field's development. And it imposes its 500/bbl/day cap on a per well basis, because individual well production rates are the best measure of whether the heavy oil property as a whole requires the incentive.

HB 207's lease-based approach does not seem suited to the kind of targeted relief, and targeted safeguards, contained in HB 325.

IV. HB 207 is Burdened By an Unrealistic Economic Test

In the Conoco decision, the hearing officer concluded that an oil company should invest in a prospective oil and gas development, and needs no incentive, if it projects a rate of return from that venture at least equal to the then-current yield on a risk-free 90-day U.S. Treasury bill. *Conoco Decision* at 10.

OXY thought this an unreasonable standard. If an investor can earn the same rate of return from: (1) a risk-laden oil venture; or (2) a T-bill, why would that investor not simply purchase the T-bills?

This standard was imposed by a prior administration. However, nothing in HB 207 expressly altered that standard. And unless and until DNR reconsiders the matter, this standard remains a formidable obstacle to any worthwhile development incentive.

V. HB 207 Fails to Achieve Three Other Goals of HB 325

Our white paper lists seven criteria for any effective heavy oil incentive. HB 207 fails each of these three:

a. *Immediacy.* As BP has testified before your committee, there is a window of opportunity for developing ANS heavy oil that, as experience has shown, may pass quickly. Mr. Boyd has testified that DNR could complete an HB 207 application for heavy oil in as few as three months. However, given that:

(1) Alaska's only prior royalty reduction proceeding, the Conoco/OXY Milne Point proceeding, required 15 months to complete simply at the agency level; and

(2) HB 207's process is considerably more complex than prior law's,^{13/}

we believe that one year is a more realistic minimum;

(b) Certainty. As you know, HB 207 accords DNR considerable discretion. Indeed, no matter how compelling the applicant's economic case, DNR remains free to deny or limit relief under an open-ended "public interest" standard. AS 38.05.180(j)(3)(A). As a result, no prudent investor would commit capital on the assumption that adequate relief under HB 207 would be granted. To the contrary, any investment decision made in 1996 would necessarily assume that relief would ultimately be denied, and

(c) Credibility. Our white paper argues that any heavy oil incentive should draw on successful experience in other oil producing jurisdictions. The Arthur D. Little report called royalty suspensions a tried and successful tool to stimulate investment in marginal fields, and the white paper lists the United States, and seven producing states, as jurisdictions that have employed royalty and tax suspension to do just that. In Texas alone, a high-cost gas well tax suspension resulted in a 400% increase in gas wells drilled, and 104,000 additional employment years, over the suspension's four-year history. *Id.* at 35

Conversely, Alaska's discretionary royalty reduction history is less encouraging. There has been only one such completed process, and after nearly four years of agency and court proceedings, the principal applicant--Conoco--sold its interest in Milne Point and left the state.

Besides its certainty, HB 325, in contrast to HB 207, benefits from its simplicity. As we've seen, the only prior completed royalty reduction proceeding in Alaska consumed 15 months before the agency. As would be the case with HB 207, each individual lessee was required to present a complete, lessee-specific economic case. Even though it owned but an 8.81% interest in Milne Point, OXY was forced to bear six-figure fees and costs associated with the application, as well as a considerable disruption of company operations.

Independent companies with smaller interests in Alaska, or with only prospective interests in the state, will not be attracted to our state by potentially complex administrative proceedings with uncertain outcomes. Once again, Arthur D. Little's

^{13/} Among the steps required by HB 207 are: (1) preparation of preliminary and final findings; (2) a mandatory 30-day public comment period; (3) possible selection of an independent consultant; (3) preparation and agency review of the consultant's report; (4) agency audits; (5) possible legislative committee review, and (6) gubernatorial review.

admonition is pertinent. Alaska, for too long, has built its royalty policies around large, profitable fields run by large interest holders. As a result, the gene pool of Alaska's oil industry continues to shrink, and reliance on HB 207 to spur ANS heavy oil development would do nothing to reverse that trend.

VI. HB 325 Enhances the Legislature's Role in Setting State Royalty Policy

HB 325 reflects the belief that, *where it is possible to do so*, the legislature itself should set royalty policy. That wasn't possible with HB 207, since its broad scope encompassed too many varying situations to admit of direct legislative management.

HB 325, on the other hand, focuses only on a single, well-understood development challenge. As a result, it invites a reassertion of legislative involvement in this sphere, if the legislature chooses to take that opportunity. In part, that's because there seems something of a consensus that ANS heavy oil is unlikely to be developed without an effective incentive. A better opportunity for direct legislative involvement is, in our view, unlikely to present itself.

On behalf of OXY, let me extend our thanks for the consideration that I know you, and the House Resources Committee members, will give to the thoughts expressed in this letter. If you or any committee member have any further questions, please don't hesitate to contact me.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

Jon K. Tillinghast

* For years, the departments of Natural Resources and Revenue took that position, and nothing has changed since the Spring of 1995 when that view was last articulated. For their part, companies such as BP, OXY, Arco and Conoco have invested over \$270 million in ANS heavy oil pilot projects over the past decade. If, for example, Schrader Bluff could be economically developed without changes in the state's fiscal structure, its owners would have plainly seized the opportunity to recover that investment a long time ago. Our white paper discusses the technical, logistic and economic hurdles associated with heavy oil development in detail, and we've heard no one suggest that the case was overstated.

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN, P.C.

The Honorable Joe Green
February 2, 1996
Page 10

cc Senator Loren Leman
Representative Norman Rokeburg
The Hon John Shively
Mr. Kenneth A Boyd
Members, House Resources Committee

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Division of Oil and Gas - Director's Office
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Fax transmittal



To: *Senator Loren Leman*

Fax Number: *907-465-3810*

From: *Ken Boyd*

Date & Time: *4/22/98*

Number of Pages (including cover sheet): *25*

Comments:

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

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April 22, 1996

The Honorable Loren Lemam
Chairman, Senate Resources Committee
Alaska State Legislature
State Capitol Building, Room 113
Juneau, AK 99801
MAIL STOP 3100

Dear Senator Lemam:

The division would like to make a few comments regarding HB 325 to the Senate Resources Committee. The division pointed out many issues pertaining to HB 325 in its letter to Representative Hanley dated February 13, 1996. (Attachment 1). While some of the problem-areas addressed in the letter have been resolved, many of the division's comments are still pertinent, and the division is prepared to address any questions the committee may have regarding that letter or this.

Heavy Oil Economics for the Milne Point Project Has Not Been Independently Analyzed.

As you may be aware, Representative Hanley requested that the division perform an economic analysis of the effect of HB 325 on royalties from the Schrader Bluff formation within the Milne Point Unit (MPU). In a hearing before the House Finance Committee, both OXY USA Inc. (Oxy) and BP Exploration (Alaska) Inc. (BPXA) offered to make available to the division the backup information supporting their economic claims in their testimony and White Paper dated January 22, 1996. This backup would have allowed the division to perform a proper, and independent, economic analysis for the House Finance Committee. The division formally requested the backup on February 9, 1996. Oxy submitted a (confidential) response on March 7. The response was lacking in some details which Oxy said BPXA would supply, and some of Oxy's assumptions seemed questionable to the division.

BPXA responded on April 8, two months after the division's request (and a week after the bill passed out of the House). BPXA provided a lot of data, but their response lacks an economic model and any explanation (in contrast to what BPXA provided in the discussion of the Northstar economics) about how the data provided translate to the economic conclusions presented in a (confidential) summary sheet. Moreover, the division has not had the opportunity to meet with BPXA geologists, engineers, and commercial staff to discuss the reasonableness of assumptions like reserve estimates, recovery rates, capital costs, operating costs, and effects of new

The Honorable Loren Leman

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April 22, 1996

technology on development. Commissioner Shively and I met with Bruce Pollicky of BPXA and discussed some of these issues. In order to expedite the division's analysis, I asked Mr. Pollicky to provide a "Northstar type" spreadsheet analysis for the MPU data under the provisions of the current form of HB 325 (because the data which BPXA did provide assumed a former version of the bill, e.g., 500 barrels of oil per day and zero percent royalty). The division has not received a response. Simply put, the division is unable to provide the Senate Resources Committee the level of economic analysis that it has provided the committee in the Northstar hearings.¹

Preliminary Analysis Shows the Milne Point Heavy Oil Project Meets the Companies' Hurdle Rates.

The division does not necessarily endorse the 15 percent hurdle rate which Oxy and BPXA claim that they need.² Nevertheless, the division's preliminary review of Oxy's information suggests that the Milne Point heavy oil project for Oxy appears to exceed the 15 percent hurdle rate without any royalty relief. BPXA's confidential summary sheet shows that at least under one scenario the Milne Point heavy oil project for BPXA would exceed the 15 percent hurdle rate without any royalty relief. The division awaits further information from the companies before reaching its conclusion.

HR 325's Economic Effect on Heavy Oil Development in Other Units Has Not Been Analyzed at All.

The division has not performed any economic analysis on the effect of HB 325 on heavy oil development in the West Sak/Schrader Bluff accumulation in the Kuparuk River Unit (KRU) or

¹ Interestingly, Oxy has asserted that the state should grant heavy oil incentives because the United States Department of Interior (DOI) did. The DOI took no action, however, until the United States Department of Energy (DOE) performed a detailed economic analysis, conducted over a two year period, of the effects of the proposed incentives on federal revenues. The analysis concluded that while royalty revenues might be reduced, overall federal revenues would increase. Furthermore, based on the analysis, the relief applied to California heavy oil production and did not apply to Wyoming production because expanding the program would have resulted in a cost to the government. Moreover, unlike the proposal in HB 325, the DOI regulation sets a sliding scale with the royalty rate at 12.5% at an API gravity of 20, and applies to properties rather than individual wells. Finally, the State and Tribal Royalty Audit Committee, which includes the State of Alaska, opposed this move by the DOI because they felt that there had been an inadequate showing of need and state revenues would be decreased. A copy of the Federal Register announcing the adoption of the final rule is provided as Attachment 2.

² Ed Behm of OXY testified that he did not know his own company's cost of capital and that overhead was not included in Oxy's economics. Without knowing this information, it is impossible to determine a company's "hurdle rate." In their White Paper at pages 23-24, BPXA and Oxy state that the hurdle rate "is built on four components :: (1) The cost of capital -- (2) Overhead -- (3) Risk -- (and 4) Profit. They also state that "these four 'hurdle rate' components combine to require at least a 15% projected rate of return from any new investment ..." If Mr. Behm does not know his own cost of capital and overhead, what was the basis for the 15% hurdle rate? If BPXA and Oxy have different cost of capital and overhead, shouldn't their hurdle rates be different?

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that accumulation in the Prudhoe Bay Unit (PBU), nor has it been asked to do so. Both units have heavy oil at depths less than 5,000 feet, the current cut-off in HB 325. Mr. Behm of Oxy testified that the West Sak/Schrader Bluff accumulation in the KRU is the same type of sands as that in the MPU. He further expected that the technology to develop the accumulation in the KRU would be the same as in the MPU. ARCO Alaska Inc. (AAI), the operator of KRU, has neither testified to the legislature nor presented information to the division regarding the bill's effect on KRU heavy oil development. Ken Thompson, AAI president, has publicly indicated that AAI may begin some heavy oil development in the KRU in the near future. BPXA is a major lease owner in the KRU.

BPXA, the operator of the West end of the PBU where heavy oil is located, has neither testified to the legislature nor presented information to the division regarding the bill's effect on heavy oil development in the PBU. John Denis, BPXA's supervisor of PBU new business development, has stated in print that initial heavy oil production in the PBU could begin as early as 1997, early enough to take advantage of the HB 325's provisions. A copy of the article describing BPXA's plans for heavy oil at the PBU is provided as Attachment 3.

HB 325 Fails to Adequately Address Innovation

The information presented by BPXA and Oxy shows that the cost of developing heavy oil has been dramatically reduced over a very short period of time. According to BPXA and Oxy, in 1984, heavy oil development costs were \$135.00/barrel. Only five years later, development costs were reduced to \$9.30/barrel, a 93 percent reduction. Current development costs are \$2.75/barrel, a 70 percent reduction from 1989. BPXA estimates costs could fall to as low as \$1.80/barrel, another 35 percent reduction. HB 325, however, has a ten year sunset even though new technology and other innovations should dramatically improve heavy oil economics in the very near future. Indeed, BPXA and the DOE are spending \$10.6 million under a cooperative agreement to study Schrader Bluff-Milne Point heavy oil development at a research facility in Oklahoma. A copy of an article discussing the research project is provided as Attachment 4. Under HB 325, even if current and future cost reduction efforts decrease the costs to the point where Schrader Bluff is much more competitive, the state will not receive any royalty for the first five years production for new wells drilled over the next ten years.

HB 325 Does Not Provide for Alaska Hire.

In the Northstar debate, the Senate Resources Committee has expressed concern over the Alaska hire provisions in the proposed amendments to the Northstar leases. HB-325 contains no local hire provision whatsoever. An analysis of royalty reduction for heavy oil under HB-207 would allow the commissioner full flexibility to negotiate local hire terms.

The Honorable Loren Leman

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April 22, 1996

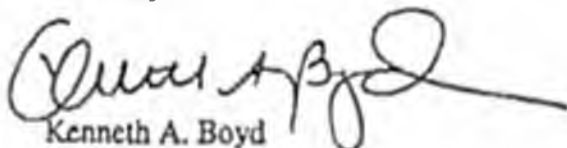
If Heavy Oil Development Would Not Occur Without Royalty Relief, Then HB207 Is the Proper Vehicle.

The royalty exemption in HB 325 is inflexible. The relief is awarded without any showing of any economic necessity. This is especially important in light of BPXA's statement that it may not need royalty relief and it may very well continue forward with heavy oil development even if it receives no royalty incentive. HB 325 does not provide the state with any upside potential. It does not require any commitment to employ Alaska residents. It does not guarantee any development. These are all factors which the commissioner of the Department of Natural Resources would consider in deciding whether to grant royalty relief under HB 207.

The administration is committed to having Alaska's oil resources developed in an environmentally and economically sound manner. It is entirely possible that some form of royalty relief will be needed to assist in getting our heavy oil resources developed. I would strongly suggest that the last two weeks of legislative session is not the most opportune time to create a new royalty policy for several billion barrels of heavy oil. While the division continues to believe that HB 207 is the proper vehicle for granting heavy oil relief if it is warranted, the next course of action may be to have industry, the State and interested legislators meet after session to craft a workable and sensible solution. As described above, the Department of Interior took a long, hard look before deciding on a royalty relief package. Even if you believe that HB-207 is not the right vehicle, we still owe the people of Alaska a careful, thorough analysis of the facts before launching into a "one size fits all" royalty reduction policy.

We will be pleased to work with the committee to help resolve this important issue.

Sincerely,



Kenneth A. Boyd
Director

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

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February 13, 1996

The Honorable Mark Hanley
Co-Chair, Finance Committee
Alaska State Legislature
State Capitol, Room 507
Juneau, AK 99801-1182
MAIL STOP 3100

Dear Representative Hanley:

Several statements have been made recently regarding the merits of HB 325 and the Department of Natural Resources' position on HB 325. In particular, I refer to Jon Tillinghast's letter on behalf of OXY USA Inc. ("OXY") to Rep. Green dated February 2, 1996, the white paper dated January 22, 1996, by BP Exploration (Alaska) Inc. ("BP") and OXY, and testimony presented to the House Finance Committee on February 8, 1996. Some of the statements that have been made are inaccurate and, in some instances, are in error. I would like to address these statements and assumptions and point out some issues that should also be considered in evaluating HB 325.

A Little Background on 'Heavy Oil.' 'Heavy oil,' as defined in HB 325 and in federal regulations, focuses on crude oil with a weighted average gravity of 20 degrees API or less, corrected to 60 degrees F. Heavy oil on the North Slope comprises one of the State's largest known, undeveloped hydrocarbon resources. The volume of North Slope heavy oil in the ground is enormous; it compares in volume to the oil originally in place in the Prudhoe Bay Unit ("PBU") Sadlerochit reservoir. It is, however, found in shallower, thinner deposits and it is much more viscous (less able to flow) than other North Slope oil. The State owns at least one eighth royalty in this resource (some of the leases have a one fifth royalty), and the resource and its infrastructure are subject to all the applicable taxing authorities of the state and local governments.

The known accumulations areas on the North Slope of 'heavy oil' that would apply to qualify for this proposed royalty exemption include (1) a large continuous accumulation in the Schrader Bluff formation that stretches across and into three different units and is called by the different operators the West Sak sands in the Kuparuk River Unit ("KRU"), the Schrader Bluff formation in the Milne Point Unit ("MPU"), and the West Sak sands in the western part of the PBU; (2) the Heavy Oil/Tar Zone of the Sadlerochit formation within the PBU; and (3) portions of the Badami Unit and the Point Thomson Unit. No heavy oil accumulations are known in the Cook Inlet area.

The Honorable Mark Hanley
Alaska State Legislature
February 13, 1996

The Schrader Bluff in the MPU and the Heavy Oil/Tar Zone of the Sadlerochit formation within the PBU would be able to take advantage of the HB 325 exemption immediately. Any production from Badami and Point Thomson is uncertain. The KRU and PBU do not have facility sharing agreements in place to permit production of oil from the West Sak sands through the existing KRU (Kuparuk formation) facilities and PBU (Sadlerochit formation) facilities.

The Division does not know if the heavy oil in the Schrader Bluff formation in the MPU or KRU will ever be produced on a large commercial scale. ARCO has indicated that it may begin development of the West Sak in the near future. BP, the largest working interest owner in the MPU, has stated that it plans to continue to work on heavy oil development even if there are no incentives granted. Although oil price will always be the primary driver in the development decision, the drilling, well completion and well production technology will influence any large-scale development decision. Heavy oil production projects undertaken so far have been small demonstration projects. Knowledge gained from heavy oil projects in more temperate climates is of some use, but on the North Slope cold temperatures decrease the ability of the heavy oil to flow or be produced to the surface.

Even when production space becomes available in the KRU, West Sak development will presumably compete with higher producing projects. Using today's proven technology, a very good West Sak or Schrader Bluff well produces 300-400 BOPD. In contrast, a new marginal well in the KRU (Kuparuk formation) produces 800 BOPD. A new well in the marginal parts of PBU (Sadlerochit) produces 1000 BOPD.

Specific comments regarding the proposed HB 325 legislation

1. A heavy oil royalty exemption pursuant to HB 325 may avoid the HB 207 process, but it may expose the state to revenue losses it might not have to incur. The currently proposed royalty exemption is inflexible. There is no discretion in this legislation and no requirement to justify the economic necessity for the royalty exemption. There is no provision that would condition the royalty exemption to require the lessees to reinvest the foregone royalty dollars in "heavy oil" projects in Alaska. This inflexibility may also mean that when the five (5) years are over, the royalty will return to its original rate causing the operator to cease production (shut-in the well).

2. Further, the first 500 bpd of heavy oil production would be exempt from royalty payment with this legislation. Under the current oil and gas production tax statutes, AS 43.55, the first 300 BOPD are exempted from production tax. If this legislation passes, the state would receive no economic return (no taxes and royalties) from the first 300 bpd per well of "heavy oil". This may raise a constitutional issue about the legislature giving away the state's income in violation of Article VIII, section 2 of the Alaska Constitution. The mandate against such 'giveaways' is embodied in AS 38.05.180(a)(1)(A).

The Honorable Mark Hanley
Alaska State Legislature
February 13, 1996

3. The legislation would apparently circumvent any negotiated agreements (unit agreements or litigation settlement agreements or HB 207 royalty reduction agreements) between the state and lessee(s) regarding the obligation to pay royalty. For example, effective December 30, 1993, the State and OXY (one of the MPU owners) entered into an agreement to settle to certain litigation between the parties. As part of this settlement agreement, the parties negotiated limits on future royalty reductions in the MPU. With respect to Schrader Bluff production from the MPU, this legislation, if passed, would circumvent the Article 5 provisions of the State/OXY settlement agreement.

4. The legislation should define 'daily production from a well' to prevent an operator from producing a well less than 24 hours in a day to qualify for the exemption. In other words, in order to qualify for the royalty exemption, 'daily production from a well' should mean continuous production from a well over a 24 hour period.

5. The definition of the term "well" needs to be addressed in the legislation. Is a sidetrack of an existing well a new well that qualifies for the royalty exemption? Do multi-lateral wellbores count as two or more separate wells? Would a dual completion count as two separate wells? Would a sidetrack drilled in 1999 from a well drilled in 1997 restart the five year clock?

6. The current wording of HB 325 uses the phrase "value at the wellhead, net of eligible field cost deductions." It is difficult to determine what value is being referenced. For State royalty purposes, the value is determined at the appropriate LACT meter for all current North Slope royalty payors pursuant to the royalty settlement agreements. Field cost deductions are allowed only in certain circumstances under the State's leases and royalty settlement agreements. Therefore, no wellhead value is ever calculated. The proposed legislation does not detail what field cost deductions are eligible but for logic and conformity sake, the value should be measured at the LACT meter before any field cost deductions.

7. Further, there is no obvious reason nor is any evidence presented as to why a "wellhead value" of \$15.00 should be the trigger for returning the royalty to its original rate. Such a value seems quite high compared to the LACT meter values seen over the past few years. A Department of Revenue economist has testified that this \$15.00 value would be approximately \$21.50 (money of the day; ANS West Coast) and the only time this price has been reached since 1987 was during the Kuwait War. Given that the legislation also includes an inflation factor, it appears unlikely that the \$15.00 threshold will ever be invoked.

8. The possibility exists that structural locations within the Kuparuk Formation in the KRU and the Sadlerochit formation in the PBU produce 'heavy oil,' that is, these reservoirs produce oil with a gravity of 20 degree API or less. Is it the intent of the legislation to exempt portions of these reservoirs from the payment of royalty?

9. As described above, where reservoir fluid properties vary across the structure, the legislation creates a situation where wells are drilled in locations to take advantage of the royalty

exemption and not in locations for more efficient reservoir management/recovery. Incentives should not be put in place that distort the efficient use of resources. This was definitely a consideration when the federal government proposed its heavy oil incentive. The BLM recently promulgated a rule (effective March 11, 1996) to reduce royalty rates for properties that produced "heavy oil" with a gravity of 20 degree API or less. The royalty reduction applies to producing properties (such as leases, units, etc.) rather than to individual wells, and is based on the weighted average gravity of the oil produced by all wells on the property. Weighted average gravity was used to prevent gravity manipulation by selective production of wells with heavier crude on a property. The use of weighted average gravity also encourages maximum recovery from all wells within a property by removing the economic advantage of selective production.

10. Thought should be given to the administrative burden created by the above situation. Incentives should not be put into place that allow "gaming the system" by selective production of wells on a lease with "heavy oil". Increased oversight would be required to monitor individual well production tests, fluid sampling from the individual wells, laboratory fluid analysis procedures, etc.

11. The heavy oil royalty exemption offers a cash incentive to the lessees on a single well basis. If the state's royalty is eliminated, an individual "heavy oil" well producing 500 hpd would not pay the following royalty, assuming a \$10.00/bbl LACT meter oil value:

$$500 \text{ BOPD} \times 0.125 \text{ royalty rate} \times \$10/\text{BO} \times 365 \text{ days/yr} = \$228,125/\text{yr}$$

[If the royalty = 20 percent, the royalty amount = \$365,000/yr]

12. What motivation do the lessees have to increase production higher than 500 BOPD if by doing so they are "penalized" by a royalty?

13. If the heavy oil wells are so marginally economic that, under an HB 207 application, plus or minus 3% (the minimum royalty under HB 207) is significant, how can those wells ever be competitive against other projects in large companies such as BP?

14. What message would this incentive send to the public and to other marginal resource producers if the heavy oil producers are given blanket relief without any requirement to show economic need? This is especially important in light of the fact that BP has stated that it does not need royalty relief and it plans to continue forward with Schrader Bluff development even if it receives no royalty incentive. Regarding BP's pending application for royalty reduction, BP was quoted as saying that

But BP says it isn't serious about the application and doesn't expect the state to approve it. It was submitted only to comply with the terms of a contract between BP and OXY USA Inc., ...OXY pays BP about \$100,000 a year under the contract, said BP

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spokesman Paul Laird, but BP has to apply for a royalty reduction to keep the money coming. ...

BP pays the state a 20 percent royalty - one out of every five barrels of oil produced - on the eight leases involved in the application; it wants that rate cut to 12.5 percent, or one in every eight barrels. ...

"We are not going in for royalty relief or restructuring for Milne," Palmer said in an interview last week. "It's not needed." ...

"BP calls request for cut a formality," Anchorage Daily News (Stan Jones) pages D-6,7, April 21, 1995.

On state incentives in general, BP has stated that incentives affect only the pace of development:

What we have said is that fiscal terms will influence the pace of development. However, we plan to continue with our work on heavy oil even if there are no new incentives. If there are incentives, then we believe that the pace of development could be accelerated.

"BP says state incentives will set the pace for North Slope oil development," Letter by James A. Palmer, Director, External Affairs, BP, Anchorage Daily News, February 7, 1996.

BP's position contradicts Mr. Tillinghast's statement that there is "something of a consensus" that "ANS heavy oil is unlikely to be developed without an effective incentive." Tillinghast, page 9. Another industry player, new to Alaska, Anadarko Petroleum Corporation ("Anadarko"), also contradicts Mr. Tillinghast's statement of consensus. This past fall, John Seitz, Vice President, Exploration at Anadarko told the Oil and Gas Policy Council that.

I hope the State resists the temptation to create a myriad of targeted incentives to prop up uneconomic production or attract ephemeral or inconsequential investment. Whatever ends up being adopted or enacted should be substantive and apply uniformly to the entire industry. We are not now, and have never been advocates of legislation or regulation that tends to provide economic "incentives" to a special class of operator or to one type of production. We are, in fact, uncomfortable when the playing field is anything but level. We are willing to compete with anybody as long as the ground rules are reasonable and universal.

[emphasis in original] Presentation to the Governor's Oil and Gas Policy Council, September 7, 1995.

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15. If indeed, development will probably take place regardless of the incentive, how can HB 325 possibly be a fiscally efficient measure and why should the State commit to giving up a right to receive income from its property if the lessees involved are unwilling to commit also at this time? HB 325 is fiscally inefficient, if measured by the conclusions reached in a recent study for the Department of Revenue on behalf of the Oil and Gas Policy Council, because it is not profit based, and because it allows a royalty reduction where none is needed. See Arthur D. Little/John Gault, "Review of International Competitiveness of Alaska's Fiscal System," Preliminary Report for the State of Alaska, Department of Revenue, September, 1995. The evidence to date, discussed above, suggests that BP does not need a royalty reduction and BP has testified that BP may go forward with the project even without the incentive. Testimony of Bruce Policky, BP, February 8, 1996, House Finance Committee. The BP/OXY white paper suggest that a 15 percent rate of return will make a project "competitive." OXY has stated that if the proposed incentive is granted, it will achieve a rate of return of 15.9 percent and will likely go forward with the project. Its rate of return without the incentive is 12.8 percent. BP testified that its rate of return is 2 to 3 percent higher than OXY's rate of return, which would put it at 14.8-15.8 without the incentive: competitive already under OXY's standards.

16. If the true motivation of this incentive is to more quickly recover development costs, the Legislature might consider a net profit share structure or other profit-based system. Profit-based systems are progressive, rather than regressive, and fiscally efficient. See Arthur D. Little/John Gault, "Review of International Competitiveness of Alaska's Fiscal System," Preliminary Report for the State of Alaska, Department of Revenue, September, 1995.

Comments on Mr. Tillinghast's letter:

17. While it is true as Mr. Tillinghast states in his February 2, 1996 letter, that the Department of Natural Resources supported HB 207 as the "first step" in implementing incentives for marginal oil fields, it does not logically follow that HB 325 is required to be the second step or is the correct second step.

18. The Governor's Oil and Gas Policy Council, which is charged with investigating and proposing such incentives, has not proposed any incentives yet. Although heavy oil was one issue discussed by the Oil and Gas Policy Council, the Council did not propose HB 325.

19. The discussions and debate leading to the enactment of HB 207 last year did not specifically exclude heavy oil, as Mr. Tillinghast's letter would imply. In fact, the very reason why the language "or pool" was added to HB 207 was to allow separate "pools" within a "field" to be granted royalty relief. The specific example used on a number of occasions was the West Sak, a heavy oil pool which is otherwise known as the Schrader Bluff pool. Commissioner Shively testified that under the new provisions of HB 207, the West Sak could qualify for

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royalty reduction while the Kuparuk pool, which underlies West Sak, might not qualify.¹ Although Mr. Tillinghast's letter on behalf of OXY suggests that the Schrader Bluff pool within the MPU cannot qualify for royalty reduction under AS 38.05.180(j) (the HB 207 reduction provisions), his statements contradict the actions of BP. BP submitted a royalty reduction application (currently suspended) for the MPU, including production from Schrader Bluff.

It is not the fact that Schrader Bluff field contains heavy oil that appears to cause OXY difficulty in approaching relief under HB 207. By prior agreement with the State, OXY is barred from applying for royalty reduction at Milne Point field for five years from July 1994 on some leases and for the life of the unit for eight specified leases. See Section 5.3 of the OXY/State Settlement Agreement. The fact that the timing of the pool's life does not, to OXY apparently, neatly fit into any of the three categories of HB 207 may be a symptom but not the root cause of OXY's problem.

Other marginal fields without heavy oil production undoubtedly fall within such a 'gray' area also. If indeed necessary, the most efficient "fix" is an amendment to the HB 207 provisions. The Division proposes that this could be accomplished by amending the language in AS 38.05.180(j)(1)(B) to read as follows:

(B) to prolong the economic life of an oil or gas field or pool as costs per barrel or barrel equivalent increase or to allow for production of a heavy oil pool, which is defined as an oil pool that produces crude oil of a weighted average gravity of 20 degrees (American Petroleum Institute) or less, corrected to 60 degrees Fahrenheit; or

20. No application for royalty relief in the Schrader Bluff pool under the HB 207 provisions has been rejected as improper under the HB 207 provisions. If the lessees truly will not go forward with any further development or operations in the Schrader Bluff pool, then any relief applied for and granted would be to "prolong the life of the pool." OXY provides no information on how or if the costs per barrel for Schrader Bluff oil are expected to increase. Therefore, opinions by some that Schrader Bluff oil cannot be granted relief under the existing statute appear premature.

21. Mr. Tillinghast's discussion of the Conoco royalty relief application is incomplete. The Conoco and OXY applications for royalty relief were initiated under the pre-HB 207 statutes. When the department denied the applications, Conoco and OXY appealed the agency decisions and initiated an independent action in the superior court. This independent superior court action slowed the agency appeal and when Conoco and OXY's independent action reached the Alaska

¹ For example: "On leases that have been developed, such as the Kuparuk-West Sak situation, DNR wants the latitude to consider royalty reductions for the West Sak reservoir, while retaining the original royalty rate for the deeper Kuparuk reservoir." Page 4, DNR's Briefing Paper for Senate Resources Committee (April 1995)

Supreme Court, it was rejected. Litigation takes time, no question about it, and the tale of the prior Conoco/OXY royalty reduction application would have been much shorter had the agency appeal been allowed to proceed and the premature action in superior court not been initiated and litigated. The current HB 207 provisions do not allow such litigation. Moreover, time has vindicated the agency's decision. BP purchased Conoco's interest in Milne Point Unit and has since then invested over \$200 million and increased production by 25% without any royalty relief. Further, according to the current operator, BP, production is expected to triple within the next few years, again without royalty relief. Any claims that Conoco left Alaska because it needed royalty relief and could not get it are clearly disproved. Conoco made its own decisions about investing and managing Milne Point and about leaving the state.

22. Mr. Tillinghast assumes that a T-bill interest rate would be imposed on a new royalty relief application. That was the rate determined by the department under the pre-HB 207 statute to be representative of a return that might be expected for a field where the major capital investments have already been made, not a field at the beginning of its development and production life. Not only does the department now have different statutory authority, but nothing would constrain it to apply that rate of return to different scenarios.

23. Mr. Tillinghast's statement that this proposal does not give any incentive to "production from other oil-bearing formations in the unit" (Tillinghast, page 6, part III) is inaccurate. Production from the Schrader Bluff pool will, to a certain degree, lower the per barrel cost of production within the unit by spreading the gross costs over a larger volume, which would increase the economic life of the other pools involved. It will also lower the TAPS tariff for all of BP's other North Slope production. An incentive therefore results.

The BP/OXY white paper dated January 22, 1996.

24. The paper discusses a pool life of 41 years for Schrader Bluff but proposes royalty suspension for individual wells. Mixing well economics and field economics results in an inaccurate analysis. Most of the wells will not have a productive life of anywhere near 41 years; therefore, the up front five year royalty suspension comprises a much larger percentage of the individual well life than it does of the total pool life.

25. Well by well economics do not reflect the integrated field economics. Any field undoubtedly has at least a few marginally economic wells; that does not necessarily put the entire field in need of royalty relief.

26. The white paper's authors assume that the State would choose a flat 5 percent royalty as the relief alternative offered. The State is not constrained to that particular figure; indeed, flexibility is one of the advantages of the HB 207 provisions. In any case, the current royalty reduction floor is 3 percent.

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27. The analysis assumes that the well costs equal the average costs of Tract 14 wells through 1991. This cost does not then take into account significant savings touted by North Slope operators like BP from advances in drilling since 1991 (when drilling on Tract 14 by Conoco ceased) such as using coiled tubing units and multi-lateral completions. The analysis does not address the cost for BP as the new operator and a party with significantly more North Slope drilling and operating experience than OXY or Conoco. The analysis does not project that the operator will most certainly be attempting to reduce costs through increased experience levels in the future. The white paper touts significant cost reduction achievements so far: from \$135MM for 13 wells and associated facilities at West Sak to \$126MM for 22 wells and associated facilities at Tract 14. BP/OXY's White Paper, page 14. Unless the lessees have abandoned all efforts at cost reduction, further increases have most likely been achieved since 1991 and should continue into the future. Under HB 325, even if current and future cost reduction efforts decrease the costs to where Schrader Bluff is much more economically competitive, the State will not receive any royalty for the first five years of any well's production.

28. The analysis assumes that operating costs remain the same as those in 1995. This presumes that 1995 was an "average" year in spite of the fact that operatorship had just changed. It also does not account for any efficiencies or economies of scale gained by increasing the size of the project and by gaining more experience or technology.

29. The analysis assumes that OXY is the appropriate corporate model to use to determine what rate of return may be expected from this project. In fact, it is likely quite the opposite. OXY has not only the minority share of the working interest (8.81%) but it also does not own downstream interests which would benefit from additional production. It would appear to be inappropriate to concentrate on royalty relief for that small interest owner when the majority interest owner (91.19%) would at the same time receive additional unaccounted for benefits for additional production (its downstream benefits and a royalty holiday on leases that have a 20 percent royalty rate).

30. The white paper refers several times to the DNR production forecast that includes Schrader Bluff production. It must be noted that the DNR forecast is a very general forecast based on minimal information about future Schrader Bluff production and little if any about the operator's internal long range plans. The white paper authors have incomparably more knowledge and data on Schrader Bluff than the DNR personnel and DNR's forecast is based on announced or existing development plans, not on speculative development.

The white paper refers to the new federal heavy oil incentive program and other state marginal well incentive programs. Several points need to be clarified here:

31. As discussed above in paragraph 9, the federal program is applied on a property by property basis, not on an individual well basis.

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32. The federal program has not yet started. It will be effective on March 11, 1996. See 81 FR 4748 (Feb. 8, 1996).

33. The federal program does not eliminate all royalty because "that would jeopardize the [Department of Interior's] efforts in securing a fair return for public land resources." 81 FR 4748. Moreover, achieving the maximum economic return is not the primary focus of the federal program. 81 FR 4750.

34. The other state programs are almost all tax incentives. There is no mention of what the corresponding royalty owners gave as incentives, if anything. A taxing authority imposes taxes pursuant to the government's sovereign powers, to raise revenue based on the existence of a property or activity within a certain area at a certain time. A royalty owner, on the other hand, is essentially receiving payment in return for allowing the lessee to take the minerals pursuant to a contract (the lease). In essence, under HB 325, the State would be giving away property with no showing of economic need to do so, and furthermore, with the knowledge that the lessees have no obligation to do anything in return.

35. Analysis of the federal heavy oil incentive program suggests that application of federal royalty policies to state royalty policies does not necessarily benefit the state and that increased production will never offset the foregone royalties. The federal revenues are only increased as a result of increased income and other taxes. Further, in the federal program, the waived royalties that the federal government is predicted to recoup as federal taxes will not necessarily 'flow through' to the affected state. There is no assurance that relief afforded under the federal program will be used to benefit lands within the borders of the state that foregoes the royalties and under HB 325, there is no assurance that the 'benefit' of the relief afforded will be reinvested in Alaska.

HB 325 does not guarantee the State anything in exchange for the incentive. There is no guarantee the companies will go forward with heavy oil production if the incentive is granted. There is also no showing that they will not go forward without it; in fact, as discussed below, quite the contrary. There is no commitment by industry that if the relief is granted, they will continue producing heavy oil once the incentive ceases. There is no requirement of reinvestment of any of the earnings in further heavy oil production or research in Alaska. Moreover, there is no commitment by industry that Alaskans will be hired for the jobs they say will be created. Nor is there any commitment to build modules for the MPU in Alaska. Under HB 207, the commissioner could insist on these types of commitments before granting royalty relief. HB 325 grants relief without any commitment.

The white paper authors also refer to Scott Goldsmith's study of the impact on the Alaskan economy in general if royalty relief were granted.

36. Contrary to what the white paper authors would imply, Mr. Goldsmith's study did not assume a royalty suspension; it assumed a flat 6 percent royalty.

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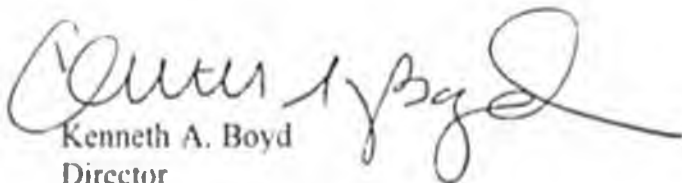
37. The Goldsmith study predicted numerous jobs being created by such royalty relief. According to the white paper, the Goldsmith study predicts that the State will add 27 additional State government jobs during the development phase and 10 additional State government jobs during the field life. It is unclear that the additional state government jobs are a real 'benefit' to society; they might be a cost instead. These jobs arise as a response to a predicted increase in demand for government services imposed by the population impact of a marginal development. What is the nature of these jobs? Without royalty on the additional production, how will these demands be met? What revenue will pay for the additional state government jobs?

Moreover, even if these industry jobs were created, there is no guarantee that the Alaskans would be hired for them and there is no guarantee that fabrication of equipment and facilities needed would be done in Alaska.

Summary. To briefly sum up a lengthy discussion, the Division of Oil and Gas maintains that any royalty reduction or royalty exemption for the production of "heavy oil" should be based on need. In the long run, a heavy oil incentive like that proposed in HB 325 should result in greater state revenues through the increased production and development of the resource. HB 325 does not meet these goals. By imposing mandatory blanket reductions, there may be insufficient relief to leases in true jeopardy, windfalls to those without need of the relief, and an inability to insure that any cost savings will be used to develop and operate the leases eligible for the relief. The process required to award a royalty reduction under the existing HB 207 provisions assures that the royalty reduction is necessary to stimulate development. Furthermore, a HB 207 royalty reduction may be conditioned to respond to changing market conditions (price), and changes in capital and operating costs as technology improves, and may include other provisions tailored to relief applied for. The Division maintains its recommendation that, if any legislative change is necessary to encompass pools such Schrader Bluff, the easiest, most effective change should be through a simple amendment to the existing AS 38.05.180(j) provisions.

This letter covers numerous issues; nevertheless, if you have further questions (or answers), please don't hesitate to contact me.

Very truly yours,



Kenneth A. Boyd
Director
Division of Oil and Gas

Attachment 2

wil

4748 Federal Register / Vol. 61, No. 27 / Thursday, February 8, 1996 / Rules and Regulations

Dated: January 2, 1996.
 William J. Muryzki,
 Acting Regional Administrator,
 40 CFR part 300 is amended as
 follows:

PART 300—(AMENDED)

1. The authority citation for part 300
 continues to read as follows:

Authority: 33 U.S.C. 1321 (e)(1); 42 U.S.C.
 6901-6937; E.O. 12777, 58 FR 34787, 3 CFR
 1991 Comp., p. 351; E.O. 12820, 52 FR 2923,
 3 CFR 1987 Comp., p. 183.

Appendix B—(Amended)

2. Table 1 of Appendix B to part 300
 is amended by removing the Clothier
 Disposal site, Greedy, New York.
 (FR Doc. 96-3718 Filed 2-7-96; 8:48 am)
 BLM WO 310-09-1210-2411

DEPARTMENT OF THE INTERIOR**Bureau of Land Management****43 CFR Part 3100**

(WO-310-09-1210-2411)

RIN 1004-ACE0

**Promotion of Development, Reduction
of Royalty on Heavy Oil**AGENCY: Bureau of Land Management,
Interior.

ACTION: Final rule.

SUMMARY: The Bureau of Land Management is issuing this final rule to amend the regulations relating to the waiver, suspension, or reduction of rental, royalty, or minimum royalty. This action is being taken to promote the production of heavy oil. The amendment establishes the conditions under which the operators of properties that produce "heavy oil" (crude oil with a gravity of less than 20 degrees) can obtain a reduction in the royalty rate. The amendment should encourage the operators of Federal heavy oil leases to place marginal or uneconomical shut-in oil wells back in production, provide an economic incentive to implement enhanced oil recovery projects, and delay the plugging of these wells until the maximum amount of economically recoverable oil can be obtained from the reservoir or field.

DATE: This rule will be effective March 11, 1996.

ADDRESSES: Inquiries should be sent to: Director (140), Bureau of Land Management, Room 335A, Main Interior Building, 1848 C Street, N.W., Washington, D.C. 20240.

FOR FURTHER INFORMATION CONTACT: Dr. John W. Hebout, Bureau of Land Management, (202) 432-0340.
SUPPLEMENTARY INFORMATION:

- I. Introduction
- II. Summary of Rule Adopted
- III. Response to Public Comments
- IV. Procedural Matters
- V. Regulatory Text

I. Introduction

A proposed rule to provide royalty relief for producers of heavy oil was published in the Federal Register notice of April 10, 1995 (60 FR 18081) with the comment period ending June 9, 1995. The comment period was reopened June 15, 1995 (60 FR 31683) and closed July 17, 1995.

On March 30, 1995, an outdated version of this proposed rule was published in the Federal Register (60 FR 18426) by mistake. That proposed rule publication was withdrawn, and the Federal Register notice of April 10, 1995 (60 FR 18081) was published in its place as the proposed rule.

The following are questions and answers designed to provide an introduction to this rule.

When does the Department of the Interior (Department) consider granting royalty relief?

In order to encourage the greatest ultimate recovery of oil and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development, may reduce the royalty on an entire leasehold or any portion thereof (Section 30 of the Mineral Leasing Act, 30 U.S.C. 209).

Existing section 3103.4-1 of Title 43, Code of Federal Regulations, provides two forms of Federal oil and gas royalty reduction—on a case-by-case basis upon application and for stripper wells. The provision concerning stripper well properties allows royalty reduction for properties that produce an average of less than 18 barrels of oil per eligible well per well-day.

The Bureau of Land Management (BLM) believes that royalty relief for producers of heavy crude oil is needed to promote the development of heavy oil.

Why is heavy oil royalty relief needed?

Above all, this royalty relief is needed to promote the development of heavy oil. Eliminating all royalties would be the most effective way to promote development, but that would jeopardize the Department's efforts in securing a fair return for public land resources. Royalty relief has to be considered in light of all the Department's responsibilities and objectives. The

balance this rule strikes is to have a royalty rate that promotes development while ensuring the public receives reasonable compensation.

Cyclical swings in the price for crude oil are common. BLM believes that future price decreases are possible, or even likely. The effect of this rule will provide a buffer against these decreases for heavy oil produced from Federal land. As many as two-thirds of all marginal properties (including non-heavy oil properties) could be lost during a period of sustained low oil prices (Marginal Wells, A Report of the National Petroleum Council, 1994, p. 3). The danger in losing the marginal wells is that, although production from individual wells may be small, their collective production is significant, accounting for one-third of lower-48 State onshore domestic production. Heavy oil production, from both Federal and non-Federal lands, makes up almost one-half of this third (Marginal Wells, A Report of the National Petroleum Council, 1994, p. 80). Heavy oil wells typically incur higher production costs, thus increasing their vulnerability. Were these heavy oil wells abandoned, the United States would lose this significant portion of domestic production.

What will happen as a result of this rule?

This rule should encourage the operators of Federal heavy oil leases to place marginal or uneconomical shut-in oil wells back in production, provide an economic incentive to implement enhanced oil recovery projects, and delay the plugging of these wells until the maximum amount of economically recoverable oil can be obtained from the reservoir or field.

According to a Department of Energy (DOE) analysis of its TORIS (Tertiary Oil Recovery Information System) data, the size of economically recoverable reserves from Federal lands will be significantly enhanced by this amendment. For instance, at a West Texas Intermediate (WTI) crude oil price of \$18 a barrel, DOE projects that this rule will increase recoverable reserves of about 54 million barrels to about 87 million barrels for the State of California. At \$18 a barrel, DOE projects that this rule will increase recoverable reserves of about 103 million barrels to about 180 million barrels for the State of California. At \$20 a barrel, DOE projects that this rule will increase recoverable reserves of about 133 million barrels to about 220 million barrels for the State of California. A proportionately larger increase in recoverable reserves is anticipated when oil prices range toward \$20 a barrel because major recovery projects may

become economically feasible. Were this rule not promulgated, DOE projects these increases in recoverable reserves would most likely occur.

Since the State of California produces almost 91 percent of lower-48 State onshore heavy oil production, the vast majority of recoverable reserve increases stemming from this royalty relief will most likely come from this State. Significant recoverable reserve increases are not anticipated in the other States since fewer properties will qualify for the relief.

When will this rule apply?

The rule will take effect March 11, 1998. However, the BLM may suspend or terminate all royalty reductions granted under this rule and terminate the availability of further relief under this rule—

(1) upon 6 month's notice in the Federal Register when BLM determines that the average WTI oil price has remained above \$14 per barrel over a period of 6 consecutive months or

(2) after September 10, 1999, if the royalty rate reductions authorized by this rule have not been effective in reducing the loss of otherwise recoverable reserves.

How will this royalty relief affect royalties and revenues?

According to the DOE TORIS analysis, although oil royalties may decline in some instances, the effects to overall Federal and State revenues should be largely neutral except in the State of California. (Revenues include all forms of income including royalties.) Slight decreases in overall revenue could be possible at some oil prices for States with moderate levels of heavy oil production. In California, the DOE analysis projects small decreases or sizable increases in State revenues depending on the price of oil (Letter Report from Department of Energy dated July 20, 1994).

II. Summary of Rule Adopted

The final rule establishes a sliding scale royalty rate for qualifying heavy-oil-producing properties. The sliding scale is intended to somewhat offset the reduced prices paid for oil as oil gravity decreases. The reduced royalty rate applies to qualifying heavy oil properties rather than individual wells, because production is normally not reported for [individual] oil wells, and is based on the average gravity of the oil weighted by the production of heavy oil from each well within the property. A weighted average gravity is used to prevent gravity manipulation by selectively producing wells on a property with heavier gravity crude. Using a weighted average of oil gravity

encourages maximum recovery from all wells within a property by removing the economic advantage of selective production.

The rule provides that either the operator (as defined at 43 CFR 3100.0-5) or the payor (as defined at 30 CFR 208.2) must calculate the weighted average gravity of the oil—measured on the American Petroleum Institute (API) scale—produced from a property every 12 months to determine the appropriate royalty rate. In no case, however, would the royalty rate exceed the rate established by the terms of the lease.

The section amended by this rule also provides for royalty rate reductions for stripper oil wells. Some provisions of this final rule are similar to the provisions of the existing regulations that pertain to stripper wells.

The final rule was modified in response to comments and for clarification. Section 3103.4 was redesigned to aid the reader in distinguishing the various forms of royalty reduction and accompanying provisions. Separate sections were established for the stripper oil and heavy oil royalty reduction provisions. The discussion of royalty rate determinations in § 3103.4-3(b)(1) was modified by adding two examples and clarifying the text. Section 3103.4-3(b)(2) was modified to extend the review period until 1998. Cross references were modified where appropriate throughout Part 3100 to reflect the redesign of § 3103.4.

III. Responses to Public Comments

A total of 309 comments were received on the proposed rule. An overwhelming majority supported the proposed rule. A few commenters recommended changes.

Comments suggested that the review period be extended for a period of 4 or 5 years rather than the 2 years stated in the proposed rule. It was always the BLM's intention that the rule be in place at least 4 years before it was evaluated. Unanticipated delays in the rulemaking process, however, have rendered the original 1997 deadline unreasonably short. Therefore, the BLM concurs with this suggestion and the rule has been modified to extend the review period until 1999.

A comment stated that the \$14 trigger for rule suspension was too high while another comment stated that \$14 was too low. Based on data developed from DOE's TORIS database, the BLM believes that \$14 is an appropriate trigger to suspend the rule. The data indicates that State and Federal Royalty reductions are offset by increased recoverable reserves up until the point

that WTI crude oil prices reach approximately \$24/bbl. Past that point, recoverable reserve increases appear to taper off. In addition, the TORIS data show that when WTI prices climb above \$24/bbl the royalty reduction is no longer a determining factor for decisions regarding investments in enhanced oil recovery techniques.

Comments suggested that the CFR 3103.4-1 regulations be revised for clarity and simplicity. The BLM agrees and has revised the section for clarity.

A comment suggested that the qualifying period for a heavy oil royalty rate reduction coincide with the one established for a stripper oil property royalty reduction. While the BLM agrees that there is value in making the stripper and heavy oil royalty rate reduction processes as similar as possible, this is not always practicable. The heavy oil rule qualifying period was made flexible in order to acknowledge the fact that many qualifying, low-production properties may not remove or sell oil every month even if their production is continuous. Thus, many properties may require even more than a calendar year (the stripper property qualifying period) to accumulate 3 months of sale or oil removal.

One comment requested that the notification period for requesting a reduced royalty rate be extended beyond the proposed 60 days. The BLM believes that 60 days is sufficient time for an operator to notify the BLM of a new royalty rate. The stripper property royalty reduction program has a similar notification period which appears to be working well.

Some comments stated that a greater royalty rate reduction was necessary. They suggested that this be accomplished by using a power curve rather than a straight line to calculate royalty rates. The BLM considered calculating royalty rates by both power curves and straight-line methods. The DOE's TORIS data, however, indicated that neither method was clearly advantageous over the other in terms of increasing recoverable reserves except within a narrow range of WTI crude oil prices. Because it is not possible to predict future oil prices, the BLM has chosen to remain with a straight-line royalty reduction for purposes of simplicity as well as to parallel the stripper property royalty reduction rule.

Some comments stated that the rule should use 25 degrees as a "heavy oil" cutoff (rather than the 20 degree proposed) in order to maximize the rule's effects and to provide the rule's benefits to as many operators as possible. Although there is no single accepted definition for "heavy oil,"

standard academic and industry practice is to reserve the term for crude oils of less than 20 degree API. The U.S. tax code also uses a 20 degree definition.

One comment stated that BLM should evaluate the stripper oil royalty reduction before granting heavy oil royalty relief. The BLM is in the process of evaluating the stripper well provisions. The stripper well provisions have not been in place long enough to make a substantive assessment.

One comment strongly opposed heavy oil royalty relief, stating that the BLM has no data which demonstrate that the leases eligible for the relief cannot be operated successfully under the lease terms or that the continued operation of such heavy crude lease is in serious, unavoidable jeopardy. Although this is an important comment, this is not the criterion for relief that is serving as the basis of this determination. The Secretary, acting through the Assistant Secretary—Land and Minerals Management, concludes, based on the DOE analysis cited in the introduction, that this rule is necessary to promote the development of heavy oil. Recoverable reserves are projected to be significantly less in the absence of the royalty relief provided by this rule.

One comment stated that this rule will provide insufficient relief on leases in true jeopardy and windfalls for those without need. The BLM believes that there are enough similarities in terms of the economic pressures on producers of heavy oil that any such relative disparities in levels of relief should be inconsequential. Furthermore, the rule is sensitive to the particular gravity of the heavy oil being produced, so that producers of less valuable heavy oil receive a higher proportion of royalty relief.

One comment stated that even if State revenues increase, royalty reductions will hurt State services. (Revenues include all forms of income including royalties.) According to the DOE analysis, the effects to Federal and State revenue should be largely neutral. Slight royalty decreases could be possible at some oil prices for States with moderate levels of heavy oil production.

In California, where almost 91 percent of the heavy oil production takes place, the DOE analysis generally projects small to moderate decreases in royalties. For instance, at \$18 a barrel (WTI), DOE projects that this rule will decrease California royalties by about \$1.3 million, while increasing California public sector revenue by about \$18 million. At \$18 a barrel (WTI), DOE projects that this rule will decrease

California royalties by about \$14 million, while decreasing California public sector revenue by about \$1 million. At \$10 a barrel (WTI), DOE projects that this rule will increase California royalties by about \$1 million, while increasing California public sector revenue by about \$104 million. The wide variations in sensitivity to the price of oil are due to numerous variables, including the propensity for oil companies to invest in major recovery projects at certain oil prices. (Letter Report from Department of Energy dated July 29, 1994.)

IV. Procedural Matters

This rule is not a major Federal action significantly affecting the quality of the human environment and that no detailed statement pursuant to Section 102 (2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) is required.

This rule has been reviewed under Executive Order 12866.

The BLM has determined that this final rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). The BLM has prepared a regulatory flexibility analysis. It is available upon request from the address listed at the beginning of this rule. Additionally, the BLM has determined, under Executive Order 12838, that the rulemaking will not cause a taking of private property.

The BLM has verified that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(7) of Executive Order 12778.

The information collection requirements of this rule have been approved by the Office of Management and Budget under 44 U.S.C. 3501 et seq. and assigned clearance numbers 1010-0040 and 1006-0143.

The principal author of this final rule is Dr. John W. Hebert, Senior Technical Specialist, Fluids Group, assisted by Charles Mui of the Regulatory Management Team, Bureau of Land Management.

List of Subjects for 43 CFR Part 3100

Land Management Bureau, Public Lands—mineral resources, Oil and gas production, Mineral royalties.

For the reasons stated in the preamble, and under the authorities cited below, Part 3100, Group 3100, Subchapter C, Chapter II of Title 43 of the Code of Federal Regulations is amended as set forth below:

V. Regulatory Text

PART 3100—OIL AND GAS LEASING

1. The authority citation for part 3100 continues to read as follows:

Authority: 30 U.S.C. 181, et seq.; 30 U.S.C. 311–316.

Subpart 3103—Fees, Rentals and Royalty

§ 3103.3-3 (Amending)

2.–3. Section § 3103.3-3 is amended by removing the cross reference “§ 3103.4-3(d)” in the introductory text and adding in its place the cross reference “§ 3103.4-4(d).”

4. § 3103.4 is amended by revising the heading to read as follows:

§ 3103.4 Production Incentives.

§ 3103.4-2 (Redesignated as § 3103.4-4)

5. Section 3103.4-2 is redesignated as § 3103.4-4.

6. Section 3103.4-1 is amended by redesignating paragraphs (c) and (d) as paragraphs (a) and (b) of a new § 3103.4-1, “Stripper well royalty reductions.” Section 3103.4-1 is further amended by redesignating paragraph (c) as (e), and revising the section heading and paragraph (b)(1) to read as follows:

§ 3103.4-1 Royalty reductions.

(b)(1) An application for the benefits under paragraph (a) of this section on other than stripper oil well leases or heavy oil properties must be filed by the operator/payer in the proper BLM office. (Royalty reductions specifically for stripper oil well leases or heavy oil properties are discussed in § 3103.4-2 and § 3103.4-3 respectively.) The application must contain the serial number of the leases, the names of the record title holders, operating rights owners (sublessees), and operators for each lease, the description of lands by legal subdivision and a description of the relief requested.

7. Newly designated § 3103.4-2, paragraph (b)(3)(ii)(A) is amended by removing the cross reference “(d)(3)(ii)” and adding in its place the cross reference “(b)(3)(ii).”

8. A new § 3103.4-3 is added to read as follows:

§ 3103.4-3 Heavy oil royalty reductions.

(a)(1) A heavy oil well property is any Federal lease or portion thereof segregated for royalty purposes, a communitization area, or a unit participating area, operated by the same operator, that produces crude oil with a weighted average gravity of less than 20 degrees as measured on the American Petroleum Institute (API) scales.

(2) An oil completion is a completion from which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced (including the entrained liquefiable hydrocarbons) or any completion producing oil and less than 80 MCF of gas per day.

(b) Heavy oil well property royalty rate reductions will be administered according to the following requirements and procedures:

(1) The Bureau of Land Management requires no specific application form for the benefits under paragraph (a) of this section for heavy oil well properties. However, the operator/payer must notify, in writing, the proper BLM office that it is seeking a heavy oil royalty rate reduction. The letter must contain the serial number of the affected leases (or, as appropriate, the communication

agreement number or the unit agreement name); the names of the operators for each lease; the calculated new royalty rate as determined under paragraph (b)(2) of this section; and copies of the Purchaser's Statements (sales receipts) to document the weighted average API gravity for a property.

(2) The operator must determine the weighted average API gravity for a property by averaging (adjusted to rate of production) the API gravities reported on the operator's Purchaser's Statement for the last 3 calendar months preceding the operator's written notice of intent to seek a royalty rate reduction, during each of which at least one sale was held. This is shown in the following 3 illustrations:

(i) If a property has oil sales every month prior to requesting the royalty rate reduction in October of 1996, the

operator must submit Purchaser's Statements for July, August, and September of 1996:

(ii) If a property has sales only every 6 months, during the months of March and September, prior to requesting the rate reduction in October of 1996, the operator must submit Purchaser's Statements for the months of September 1993, and March and September 1996; and

(iii) If a property has multiple sales each month, the operator must submit Purchaser's Statements for every sale for the 3 entire calendar months immediately preceding the request for a rate reduction.

(3) The following equation must be used by the operator/payer for calculating the weighted average API gravity for a heavy oil well property:

$$\frac{(V_1 \times G_1) + (V_2 \times G_2) + (V_n \times G_n)}{V_1 + V_2 + V_n} = \text{Weighted Average API gravity for a property}$$

Where:

- V₁ = Average Production (bbls) of Well #1 over the last 3 calendar months of sales
- V₂ = Average Production (bbls) of Well #2 over the last 3 calendar months of sales
- V_n = Average Production (bbls) of each additional well (V₁, V₂, etc.) over the last 3 calendar months of sales

- G₁ = Average Gravity (degrees) of oil produced from Well #1 over the last 3 calendar months of sales
- G₂ = Average Gravity (degrees) of oil produced from Well #2 over the last 3 calendar months of sales
- G_n = Average Gravity (degrees) of each additional well (G₁, G₂, etc.) over the last 3 calendar months of sales

Example: Lease "A" has 3 wells producing at the following average rates over 3 sales months with the following associated average gravities: Well #1, 4,000 bbls, 13° API; Well #2, 6,000 bbls, 21° API; Well #3, 2,000 bbls, 14° API. Using the equation above—

$$\frac{(4,000 \times 13) + (6,000 \times 21) + (2,000 \times 14)}{(4,000 + 6,000 + 2,000)} = 17.2 \text{ Weighted Average API gravity for property}$$

(4) For those properties subject to a communication agreement or a unit participating area, the weighted average API gravity for the lands dedicated to that specific communication agreement or unit participating area must be determined in the manner prescribed in paragraph (b)(1) of this section and assigned to all property subject to Federal royalties in the communication agreement or unit participating area.

(5) The operator/payer must use the following procedure in order to obtain a royalty rate reduction under this section:

- (i) Qualifying royalty rate determination.
 - (A) The operator/payer must calculate the weighted average API gravity for the property proposed for the royalty rate reduction in order to verify that the property qualifies as a heavy oil well property.
 - (B) Properties that have removed or sold all less than 3 times in their productive life may still qualify for this royalty rate reduction. However, no additional royalty reductions will be granted until the property has a sales history of at least 3 production months (see paragraph (b)(1) of this section).
 - (C) Calculating the qualifying royalty rate. If the Federal lease or production sharing (e.g.,

communication or unit agreements) qualify as heavy oil property, the operator/payer must use the weighted average API gravity rounded down to the next whole degree (e.g., 11.7 degrees API becomes 11 degrees), and determine the appropriate royalty rate from the following table:

ROYALTY RATE REDUCTION FOR HEAVY OIL

Weighted average API gravity (degrees)	Royalty Rate (percent)
6	0.5
7	1.4
8	2.3
9	3.1
10	3.9
11	4.8
12	5.6
13	6.5
14	7.4
15	8.2
16	9.1
17	10.0
18	10.8

ROYALTY RATE REDUCTION FOR HEAVY OIL—Continued

Weighted average API gravity (degrees)	Royalty Rate (percent)
19	11.7
20	12.5

(ii) New royalty rate effective date. The new royalty rate will be effective as the first day of production 3 months after BLM receives notification by the operator/payer. The rate will apply to all oil production from the property for the next 12 months (plus the 3 calendar month grace period during which the next 12 months' royalty rate is determined in the next year). If the API oil gravity is 20 degrees or greater, the royalty rate will be the rate in the lease terms.

Example: BLM receives notification from an operator on June 8, 1996. There is a two-month period before new royalty rate is

4752 Federal Register / Vol. 61, No. 27 / Thursday, February 8, 1996 / Rules and Regulations

effective—July and August. New royalty rate is effective September 1, 1996.

(iv) *Royalty rate determinations in subsequent years.*

(A) At the end of each 12-month period, beginning on the first day of the calendar month the royalty rate reduction went into effect, the operator/payer must determine the weighted average API oil gravity for the property for that period. The operator/payer must then determine the royalty rate for the following year using the table in paragraph (b)(5)(ii) of this section.

(B) The operator/payer must notify BLM of its determinations under this paragraph and paragraph (b)(5)(iv)(A) of this section. The new royalty rate (effective for the next 12 month period) will become effective the first day of the third month after the prior 12 month period comes to a close, and will remain effective for 12 calendar months (plus the 1 calendar month grace period during which the next 12 months' royalty rate is determined in the next year). Notification must include copies of the Purchaser's Statements (sales receipts) and be mailed to the proper BLM office. If the operator does not notify the BLM of the new royalty rate within 60 days after the end of the subject 12-month period, the royalty rate for the heavy oil well property will return to the rate in the lease terms.

Example: On September 10, 1997, at the end of a 12-month royalty reduction period, the operator/payer determines what the weighted average API oil gravity for the property for that period has been. The operator/payer then determines the new royalty rate for the next 12 month using the table in paragraph (b)(5)(ii) of this section. Given that there is a 2-month delay period for the operator/payer to calculate the new royalty rate, the new royalty rate would be effective December 1, 1997 through November 10, 1998 (plus the 1 calendar month grace period during which the next 12 months' royalty rate is determined—December 1, 1998 through January 31, 1999).

(v) *Prohibition.* Any heavy oil property reporting an API average oil gravity determined by BLM to have resulted from any manipulation of normal production or adulteration of oil sold from the property will not receive the benefit of a royalty rate reduction under this paragraph (b).

(vi) *Certification.* The operator/payer must use the applicable royalty rate when submitting the required royalty reports/payments to the Minerals Management Service (MMS). In submitting royalty reports/payments using a royalty rate reduction authorized by this paragraph (b), the operator/payer must certify that the API oil gravity for the initial and subsequent

12-month periods was not subject to manipulation or adulteration and the royalty rate was determined in accordance with the requirements and procedures of this paragraph (b).

(vii) *Agency action.* If an operator/payer incorrectly calculates the royalty rate, the BLM will determine the correct rate and notify the operator/payer in writing. Any additional royalties due are payable to MMS immediately upon receipt of this notice. Late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102. The BLM will terminate a royalty rate reduction for a property if BLM determines that the API oil gravity was manipulated or adulterated by the operator/payer. Terminations of royalty rate reductions for individual properties will be effective on the effective date of the royalty rate reduction resulting from a manipulated or adulterated API oil gravity so that the termination will be retroactive to the effective date of the improper reduction. The operator/payer must pay the difference in royalty resulting from the retroactive application of the non-manipulated rate. The late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102.

(8) The BLM may suspend or terminate all royalty reductions granted under this paragraph (b) and terminate the availability of further heavy oil royalty relief under this section—

(i) Upon 6 months' notice in the Federal Register when BLM determines that the average oil price has remained above \$24 per barrel over a period of 6 consecutive months (based on the WTI Crude average posted prices and adjusted for inflation using the implicit price deflator for gross national product with 1991 as the base year), or

(ii) After September 10, 1999, if the Secretary determines the royalty rate reductions authorized by this paragraph (b) have not been effective in reducing the loss of otherwise recoverable reserves. This will be determined by evaluating the expected versus the actual abandonment rate, the number of enhanced recovery projects, and the amount of operator reinvestment in heavy oil production that can be attributed to this rule.

(7) The heavy oil well property royalty rate reduction applies to all Federal oil produced from a heavy oil property.

(8) If the lease royalty rate is lower than the benefits provided in this heavy oil well property royalty rate reduction program, the lease rate prevails.

(9) If the property qualifies for a stripper well property royalty rate reduction, as well as a heavy oil well

property reduction, the lower of the two rates applies.

(10) The operator/payer must separately calculate the royalty for gas production (including condensate produced in association with gas) from oil completions using the lease royalty rate.

(11) The minimum royalty provisions of § 2103.3-2 will continue to apply.

§ 2140.1-4 (Amended)

9. Section § 2140.1-4(c)(3) is amended by removing the cross reference "§ 2103.4-1" and adding in its place the cross reference "§ 2103.4."

§ 2155.1 (Amended)

10. Section § 2155.1(a) is amended by removing the cross reference "§ 2103.4-1" and adding in its place the cross reference "§ 2103.4-4."

Dated: November 2, 1995.

Bob Armstrong,

Assistant Secretary of the Interior,

[FR Doc. 96-4431 Filed 2-7-96; 8:43 am]

BLM/OS/008 4219-2007

48 CFR Public Land Order 718

(OR-843-1435-01; OPL-194; OR-23118 (WASH))

Revocation of Secretarial Order of June 17, 1968; Washington

AGENCY: Bureau of Land Management, Interior.

ACTION: Public Land Order.

SUMMARY: This order revokes in its entirety a Secretarial order which withdrew 20 acres of National Forest System land for use by the Forest Service, Department of Agriculture, for the Laurier Administrative Site. The land is no longer needed for this purpose and the revocation is needed to permit disposal of the land through exchange. This action will open the land to surface entry, subject to Section 24 of the Federal Power Act. The land is temporarily closed to mining by the Forest Service exchange proposal. The land has been, and will remain open to mineral leasing.

EFFECTIVE DATE: March 11, 1996.

FOR FURTHER INFORMATION CONTACT: Betty McCarthy, BLM Oregon/ Washington State Office, P.O. Box 2888, Portland, Oregon 97208-1945, 503-252-8115.

By virtue of the authority vested in the Secretary of the Interior by Section 204 of the Federal Land Policy and Management Act of 1976, 48 U.S.C. 1714 (1988), it is ordered as follows:

1. Secretarial Order dated June 17, 1968, which withdrew the following

PETROLEUM NEWS

EXPLORATION & PRODUCTION

Attachment 3

FIELD REPORTS

Report on North Slope field activity

BP promises to bring Milne Point back online, after...
operations, your long effort to double crude yields.

Milne Point appears to be the final piece of North Slope activity in operation BP Exploration...
bringing the field back on-line this month.

The field was shut down on March 18 for major upgrades to the...
year-long effort to double crude yields. The project has absorbed more than \$100 million in...
costs and 2000 wells and systems.

When the field is restarted about mid-April, crude production will be...
and to over 20,000 barrels a day by the end of the year. Milne Point was producing about 10,000 barrels a day when it was...
shut down for repairs last month, roughly 1,000 barrels a day more than when BP...
started the area this summer.

Concrete pipelines around...
the field will be completed by...
end of the year.

Additional production is...
from BP's...
operations when the field is brought...
on-line in October.

Maintenance...
operations is...
drilling contracts in...
and about 80 percent of the...
operations is completed. The...
operations is expected to...
add 10,000 to 15,000 barrels of...
production.

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EXPLORATION

BP Identifies Prudhoe Bay satellite accumulations lying on top of main producing formation

Pools were found when field was...
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Estimates of...
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Map showing...
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Attachment 4

PETROLEUM NEWS • ALASKA 23

PETROLEUM ANALYSIS

PETROLEUM NEWS • ALASKA 27

EXPLORATION & PRODUCTION

RESEARCH

BP, DOE kick-off Bartlesville heavy oil research project

The prize: Two billion barrels in place at Milne Point, with potentially 800 million barrels recoverable

By Kristen Hudson
PWI News Editor

Amstarco Hess "built up a huge exploration position" on the North Slope during the 1970s and 1980s, Van Dyle said.

"Obviously, they had an interest in Alaska because of their substantial (holdings) across the slope," he added.

Van Dyle said that while the company was an active explorer, it was never able to become a field operator, or a major producer on the North Slope.

"The one area where they had a strong interest was Nordstar," he said. "But, for whatever reason, they never saw it as an economic prospect."

The state's largest oil producer, BP has not only taken over Nordstar but intends to develop its estimated 130 million barrels of crude reserves, if it can gain financial incentives from the state.

However, BP believes it can develop the oil-rich field for about \$178 million, compared to the enormous \$1.8 billion price tag Amstarco Hess had put on the project.

"Their view of the North Slope was different because they weren't an operator," Van Dyle said. "They just didn't have the on-ground experience."

heavy oil fields of Alberta and Saskatchewan.

Koch is one of the largest Canadian exporters of heavy oil and one of the top five producers in Alberta's Cold Lake region, with plans to boost output to 40,000 barrels per day from 16,000. Much of Koch's production is piped to its 200,000-barrel-per-day Pico River upgrader in Minnesota.

Like Koch, Enxco has made recent purchases of heavy oil reserves and has doubled its output to 17,000 barrels per day. The company's output of heavy oil

A government-sponsored Bartlesville, Okla., research facility that has been involved in petroleum technology development since 1918 is working with BP Exploration (Alaska) Inc. on ways to make heavy oil recovery from Schrader Bluff-Milne Point on Alaska's North Slope economic.

The heavy oil prize at Milne Point is more than 2 billion barrels of oil in place, with potentially 200 million to 800 million barrels recoverable.

The 800-million-barrel end of the range would require enhanced oil recovery, which is the type of process targeted by the \$10.6 million five-year cooperative research and development agreement between BP, the U.S. Department of Energy and BDM-Oklahoma, which operates DOE's National Institute of Petroleum and Energy Research in Bartlesville.

Arden Sryckler, manager of thermal and gas-enhanced oil recovery for BDM-Oklahoma, said the project officially started with a kick-off meeting between BP and BDM in Bartlesville Jan. 31.

The government will fund the work at BDM, Sryckler said, adding that while

DOE has committed to the project it hasn't actually funded it yet. BP will fund most of the \$10.6 million in-house, including a pilot project at Schrader Bluff.

This year BDM-Oklahoma essentially will look at all the options, reviewing heavy oil development processes which have been used elsewhere, Sryckler said. The unique conditions in Alaska may require that we do things differently, but for a first year BDM will look at what has been done elsewhere and see what might work, he said. Methods for review include air injection and carbon dioxide or natural gas floods. After a review of processes used elsewhere, BDM may be involved in laboratory work and some mechanistic work, while BP will do some simulation work and the focused work leading up to a pilot project.

Cooper began heavy oil production from the Milne Point-Schrader Bluff accumulation, and pioneered many of the primary recovery technologies now in use there. BP's manager of subsurface engineering at Milne Point, Bruce Polinsky, said in December. Since acquiring the field in 1993, BP has drilled test wells and reduced drilling and casing costs, but hasn't yet reduced completion costs, Polinsky said.

million barrels of reserves, from Amstarco Canada.

But not everyone is a winner. Two Saskatchewan upgraders, located with capacity to process 200,000 barrels of

oil remain idle for a \$1.5 billion upgrade handling 180,000 barrels per day. While it started the project in the early 1980s it has said technological developments could

round. As much as \$115 million is said to be available.

Wildlife toll

Meanwhile, cleanup teams were tackling a 70,000 metric ton spill that blackened an estimated 35 miles of coastline and began to hit bird sanctuaries and wildlife.

BBC radio said the cost of cleaning up the oil slick had been estimated at £10 million (\$15 million).

A Royal Society for the Protection of Birds (RSPB) official said compensation for the earlier Braer tanker spill amounted to £40-50 million (\$60-75 million). "...but we've talked to some people who expect it to be well above this for the Sea Empress."

The Braer ran aground in the Shet-

land Islands off northern Scotland in January 1993. During a few days the vessel broke up on rocks, spilling more than 80,000 metric tons of crude oil in U.K.'s biggest tanker spill (OGJ, Jan. 11, 1993, p. 26).

The RSPB official said on Feb. 27 about 4,500 oiled birds had been found so far in the Milford Haven area, and the toll was "growing daily and quickly." RSPB expects 7,000-8,000 oiled birds to be recovered before the slick is cleaned up. "...but we will have no idea how many will simply sink to the bottom."

One press report said about 30 gray seals, normally resident on the Skomer Island bird sanctuary off the coast west of Milford Haven, had been seen swimming in oil.

Study centers on N. Slope heavy oil

The U.S. Department of Energy has approved a project aimed at developing methods to economically recover heavy oil in Schrader Bluff-Milne Point field on Alaska's North Slope.

Participants in a cooperative research and development agreement (Crada) for the demonstration program are BP Exploration (Alaska) Inc., DOE, and BDM-Oklahoma Inc., operator of DOE's National Institute of Petroleum & Energy Research (Niper), Bartlesville, Okla.

The seventh Crada involving participation by DOE and BDM-Oklahoma and cost-sharing by industry, it has the highest dollar value of any of the Cradas so far. Total funding is to be \$10.6 million during 5 years.

Schrader Bluff-Milne Point field, covering more than 32,000 acres 12 miles west of giant Prudhoe Bay oil

and gas field, is estimated to hold more than 2 billion bbl of 18-22° gravity oil.

"The reservoir and oil characteristics of Schrader Bluff make it a potential candidate for various enhanced oil recovery projects," said Arden Strycker, manager of thermal and gas enhanced oil recovery for BDM-Oklahoma at Niper.

Among the methods that have been considered are air injection (combustion), various floods such as carbon dioxide or natural gas, and, to a lesser degree, steamflooding. Scoping studies with these processes have yielded potential recoveries of 12-47% beyond what is currently possible using conventional waterflood.

The main research goal will be to evaluate the most efficient, economic method of oil recovery for the field. The best recovery method will then be verified in a pilot field test.

Cairn tests gas strike off Bangladesh

A discovery by Cairn Energy plc, Edinburgh, in the Bay of Bengal has raised hopes for a new gas play off Bangladesh.

Exploration in Bangladesh has until recently focused in the northeast onshore region, but Cairn's Sangu-1 wildcard in Block 15 is said to have achieved the highest combined recorded flow rate for the country.

Cairn said its Sangu-1 flowed a maximum 50 MMcf/d from a main gas bearing zone on test. A later test of a shallower formation located the well's combined flow to 82 MMcf/d.

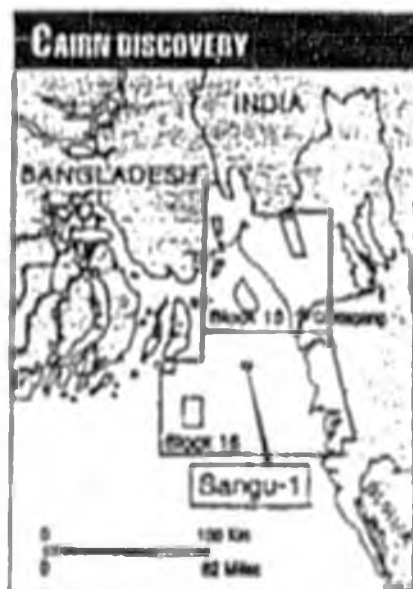
Khandakar Mosharrat Hossain, Bangladesh's minister of energy and mineral resources, said, "The discovery

is of major significance to Bangladesh, opening a new hydrocarbon province.

"It extends the hitherto known hydrocarbon area of the country from the eastern part to the south and west, including offshore. This should lead to rapid development of gas based industries and additional power for the country."

Cairn said other gas bearing zones in Sangu-1 were not tested. The well has been completed as a potential producer and the rig moved to drill the Sangu-2 appraisal, 5 km north. Drilling is expected to require 30-40 days.

Malcolm Thomas, Cairn's general manager, commercial, said his company is tentatively assessing develop-



ment options.

"The most likely development would be pretty straightforward," he said. "Conditions in the area are like the Gulf of Mexico, with water only 20-40 ft deep."

Thomas said Sangu most likely would be developed using a small platform over a template on the site of the discovery well. One or two more wells would be drilled through the template to establish base production.

Sangu gas is 96% methane, with no hydrogen sulfide and little carbon dioxide. There is no potential for liquids recovery, so processing requirements would be simple.

The discovery is 40 km offshore. While an export pipeline to shore is feasible, it "...needs more thought" than development options because of strong currents in the Mouths of the Ganges area between the discovery and the shore.

Cairn holds two exploration licenses, Blocks 15 and 16, off Bangladesh.

Amoco scores off Trinidad-Tobago

Amoco Trinidad Oil Co. has string together four offshore discoveries in four attempts in an exploration program east of Trinidad and Tobago.

Amoco said combined reserves of the strikes could furnish more than half the feed needed to supply an additional train for a proposed gas liquefaction project in Trinidad and Tobago, as well as provide a secure gas supply for other domestic uses.

Amoco, which holds 100% interests in all the discoveries, disclosed the two

*An Opportunity to Develop
Alaska's Heavy Oil Resources...*

**BP Exploration (Alaska) Inc.
OXY USA Inc.**

January 22, 1996

An Opportunity to Develop Alaska's Heavy Oil Resources...

I. Summary

Underlying the Milne Point and Kuparuk River units on Alaska's North Slope is a series of shallow, heavy oil sands that form the largest proven, undeveloped oil field in the United States. If development of those sands were economic, a billion or more barrels of oil could be recovered.

Beneath the Milne Point Unit alone, in the Schrader Bluff Formation, there are about 300 million barrels of recoverable heavy oil.^{1/} Initial development of that resource would entail drilling some 230 wells over a nine-year, labor-intensive development period, with peak production reaching at least 45,000 barrels per day. According to the University of Alaska, that activity would spawn

Shallow Oil Sands Nomenclature

AGE	TYPE LOG		TERMINOLOGY		
	MILNE POINT UNIT	RESERVOIR	Informal Milne Point Unit	Informal Kuparuk Unit	Formal North Slope
TERTIARY			K Sands	UPPER	SAGAYAH BRKTDK
			L Sands	UGNU SANDS	
			M Sands	LOWER	PRINCE CREEK
			N Sands		
CRETACEOUS			O Sands	WEST SAK SANDS	COLVELL

Chart 1

- ◊ Capital development expenditures of \$550 million, of which 61% or about \$333 million, would be spent in Alaska.

^{1/} See Bidinger and Dillon, *Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels*, SPE 30289 (available through BP Exploration (Alaska) Inc.). The Schrader Bluff sands, in relation both to other heavy oil sands at Milne Point and the West Sak Sands at the Kuparuk River Unit, are depicted in Chart 1.

- ◊ *Production expenditures of \$601 million spread over a 41-year field life, of which 85%, or about \$511 million, would be spent in Alaska;*
- ◊ *Around 360 new high-paying jobs during the development phase, and 134 new high-paying jobs during the 41-year production phase. 75-80% of those jobs would be filled by Alaska residents, resulting in additional Alaska resident payroll of \$171 million throughout the development phase, and \$7.4 million annually during the production phase; and*
- ◊ *65 new public sector jobs created during the development stage as a result of this increased economic activity, and 25 new public sector jobs created during the 41-year production phase.^{7/}*

And that, UAA projects, would flow solely from initial development of Schrader Bluff alone. All tolled, there are nearly 26 billion barrels of heavy oil underlying existing North Slope units--making ANS heavy oil a resource comparable to Prudhoe Bay. Successful initial development of Schrader Bluff could well result in technology transfers to other heavy oil lessees, and development of additional heavy oil deposits on the North Slope.

For the time being, however, and save for some minimal production from a Schrader Bluff pilot project, Alaska's heavy oil resources aren't being developed. Heavy oil is a thick and uncooperative substance, and its production poses a challenge to industry and governments worldwide.^{7/} For its part, Alaska's oil industry has

^{7/} University of Alaska Anchorage, School of Public Affairs and Institute of Social and Economic Research, *"Heavy Oil Development: The Economic Impact,"* December, 1995.

^{7/} Because heavy oil fields are "less attractive," Arthur D. Little recently told the Governor's Oil & Gas Policy Council, "changes in [government] fiscal terms may be necessary." Arthur D. Little/John Gault, *"Review of International Competitiveness of Alaska's Fiscal System,"* Preliminary Report for the State of Alaska, Department of Revenue, September, 1995 (*"Little Report"*) at 138. Guatemala, for example, imposes a lower royalty on heavier oil, according to a sliding scale based on the oil's viscosity. Ecuador does the same thing. *Id.* at 139-40. The U.S.

invested nearly \$270 million in the past decade tackling the technical barriers to lifting heavy oil from the cold, unconsolidated sands of the North Slope.

From an engineer's viewpoint, that pioneer effort succeeded. Complex and innovative completion technology was developed that can pull heavy oil from those sands at a sustained rate. But from an investor's eye, the pilot projects remain unconvincing. Initial flow rates from Schrader Bluff heavy oil wells have averaged only 275 barrels per day--far below the economic margin in this hostile working environment. ¹

As a result, additional Schrader Bluff development is not expected to yield the minimal rate of return necessary to justify the requisite capital investment. Indeed, over the past several years, and through the Spring of 1995, the state itself has largely written the resource off--at least for the foreseeable future. The Alaska Department of Natural Resources' March, 1995 oil production forecasts, for example, concluded that Milne Point would produce no more heavy oil over the next 20 years than that currently lifted from the unit's small pilot project. ¹

Department of Interior, Bureau of Land Management, has also proposed reduced royalties for heavy oil production, again on a sliding scale basis. 60 *Federal Register* 18081 (April 10, 1995).

¹ By comparison, initial production rates from individual Prudhoe Bay wells reached 25,000 bbls./day. Even initial production of lighter oil from Milne Point's Kuparuk formation--which observers uniformly acknowledge to be at the ANS margin--averaged 862 bbl./day.

¹ DNR, *Historical and Projected Oil and Gas Consumption*, March, 1995 at 6-7. The same conclusion was reached in the Spring, 1995 Department of Revenue ("DOR") forecasts. DOR, *Revenue Sources Book*, Spring, 1995 at Table 24 (base case).

The Fall, 1995 DOR forecasts use a different approach for predicting future revenues from undeveloped ANS resources. Those Fall, 1995 forecasts include considerably more near-term production from a variety of speculative projects such as North Star, Schrader Bluff, Mikkelson Bay and Colville River Delta than did the Spring, 1995 DOR projections, although even here Schrader Bluff production isn't projected to peak, at 45,000 bbls./day, until 2005. *Revenue Sources*, Fall, 1995, Table 22. The forecasts' Schrader Bluff figures begin with the unit's business plan projections for Schrader Bluff development discussed in Section III(A), *post*, then risk-discount those projections by about 25%. (cont'd)

That discouraging forecast, however, needn't necessarily be, and this paper proposes a special royalty structure for new ANS heavy oil development that may materially change project economics. The proposal was developed in response to the invitation extended to Alaska's private sector by Governor Knowles and his Oil & Gas Policy Council to explore new partnerships to guide Alaska's economy into the 21st century.

The proposal, embodied in HB 325, would suspend royalties for the first five years of production from any new ANS heavy oil well drilled after June 30, 1996. When the suspension ended, royalties would return to the full lease rate.⁷ The suspension would apply only to the first 300 bbls./day of production from each well.

The Fall forecasts' methodology reflects the assumption that some development from various problematic ANS resources will likely occur, and that by spreading that *regional* prognosis over several prospects on a risk-discounted basis, the forecasts can paint a rough picture of plausible future production from the region as a whole without staking that projection on the fate of any one particular field. *Id.*, see p. 19. Indeed, the forecasts do not purport to conclude that development of any single marginal prospect will or will not be economic.

Inclusion of Schrader Bluff in that mix of regional possibilities is encouraging, since it seemingly reflects a growing recognition that, with an improved economic environment, ANS heavy oil is a potentially developable resource. That recognition, in part, may be attributable to the considerable attention that heavy oil received in the Summer of 1995, both before the Oil & Gas Policy Council and the legislature.

On the other hand, nothing occurred between the Spring and Fall of 1995 to warrant an about-face in the state's longstanding belief that, *under the fiscal status quo*, ANS heavy oil development will likely not happen in the foreseeable future. No technological or production breakthroughs occurred between the Spring and Fall forecasts, and the Fall, 1995 DOR projections' "long range price forecast is almost identical to last spring's." *Revenue Sources*, Fall, 1995, cover letter at 1.

For all these reasons, the Fall, 1995 DOR forecasts shouldn't be viewed as heralding any reversal in the state's outlook for Schrader Bluff development in the absence of some change in the fiscal environment.

⁷ At Milne Point, for example, BP Exploration (Alaska) Inc., which owns 91.19% of Milne Point, would pay 12.5% on production assigned to some leases, and 20% on production assigned to others. OXY USA Inc., which owns the remaining 8.81% of the unit, would pay 12.5% on its share of production.

Any partnership should benefit each partner equally, and this proposal was tailored to accomplish that goal. For example:

From the state's perspective:

- ◇ *Given the unusually long life of heavy oil fields--in Schrader Bluff's case, an estimated 41 years--the state benefits more from incentives granted only for a finite period at the outset of production, rather than from more gradual incentives granted over the life of the field;*
- ◇ *The cost of administering the incentive is negligible;*
- ◇ *Suspensions have proven to be an effective tool in other oil producing jurisdictions to spur development of marginal fields. The state would be treading on proven ground;*
- ◇ *Only new heavy oil wells would benefit from the incentive, and for years now the state has assumed that no new heavy oil development will occur in the foreseeable future. As a result, the revenues contemplated by the state's various royalty agreements would be unimpaired;*
- ◇ *The short period of the incentive minimizes the state's exposure to unanticipated oil price increases or technological breakthroughs that might make heavy oil development more profitable. The state's window of exposure would be five years for each well, rather than over a 41-year field life; and*
- ◇ *By fashioning a specific incentive targeted to a single important resource, the state needn't re-invent overall state royalty policy or risk unintended consequences elsewhere.*

Conversely, from the investor's perspective:

- ◇ *The incentive is targeted at the initial years of production, and is therefore especially effective in allowing recovery of the lessee's capital investment in a reasonable period of time;*
- ◇ *The incentive would be available immediately;*
- ◇ *Because the incentive is granted by operation of law, its availability is certain, and serious investment decisions can be made in reliance on it; and*

- ◊ *Available economic and technical information suggests that this incentive will, in fact, materially improve the attractiveness of investing in ANS heavy oil development.*

Alaska's heavy oil reserves are an important public asset, and there are no risk-free options for managing it. One possibility, of course, is to wait things out, hoping for some unexpected, sustained oil price increase, or some technological advance, that would make heavy oil development attractive without any incentives. However:

- ◊ *As Arthur D. Little recently warned the Oil & Gas Policy Council, a "wait and see" strategy runs its own risks, since at some point the Trans Alaska Pipeline will no longer be available at a reasonable per-barrel tariff, if at all;*
- ◊ *In the case of ANS heavy oil, that risk is compounded by the fact that, even with incentives, heavy oil development may be economic only because it can share an existing infrastructure at Milne Point and Kuparuk River. In this respect, DNR's February, 1994 production forecasts predicted that Milne Point would be abandoned in 2006, while that agency's 1995 projections pegged the unit's abandonment date at 2011; ⁷ and*
- ◊ *History has proven that progress in tackling the challenge of ANS heavy oil development is very much a child of momentum. Discouraging results have, time and again, led to years of inactivity as interest inevitably turns to more cooperative resources. See Section II(D), post. Putting ANS heavy oil on the public back burner may leave it there far longer than decision-makers intended.*

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⁷ DNR, *Historical and Projected Oil and Gas Consumption*, February, 1994 at 6-7; March, 1995 at 6-7.

It's time to make a decision about Alaska's heavy oil. Even if the ultimate choice is to wait and see, the debate initiated by Governor Knowles will at least assure that the decision is purposeful.

The issue raised by this paper is how to optimize the public's return on a significant asset. It is not about trading jobs for royalties. As this paper will explain, and as Chart 2 illustrates, the underlying

premise of this proposal is that the state will receive more royalties from heavy oil development by adopting the incentive than by maintaining the *status quo*. Indeed, if the state's policy-makers conclude otherwise, there is little sense doing what this paper proposes.

Two Paths for Schrader Bluff

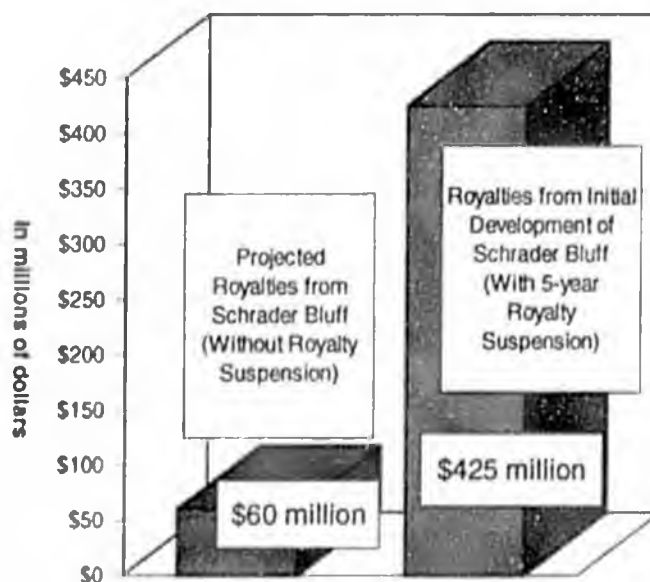


Chart 2. ^{1/}

^{1/} Source: Applicable royalty rates were applied to: (1) DNR's Spring, 1995 production forecasts for Schrader Bluff, discussed *ante*; then to (2) lessee projections of likely future production from initial Schrader Bluff development. Projected oil prices were taken from the Alaska Department of Revenue's Spring, 1995 *Revenue Sources Book's* base case. Dollars expressed are nominal.

Every management option available to the state carries its own mix of risk and potential reward. We believe that a careful balancing of those options will lead decision-makers to look carefully at the kind of tailored incentive contained in HB 325.

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II. Background: Milne Point and Heavy Oil

A. An Overview of the Milne Point Unit.

The Milne Point Unit lies 12 miles west of Prudhoe Bay. *Chart 3.*

The unit was developed in the 1980's by Conoco Inc., Chevron and OXY USA Inc. ("OXY").

In late 1993, Conoco and Chevron sold their interest in the unit to BP Exploration (Alaska) Inc. ("BP"), and today 91.19% of the unit is owned by BP, and the remaining 8.81% by



North Slope Fields and Milne Unit Outline

Chart 3

Production Formations at Milne Point

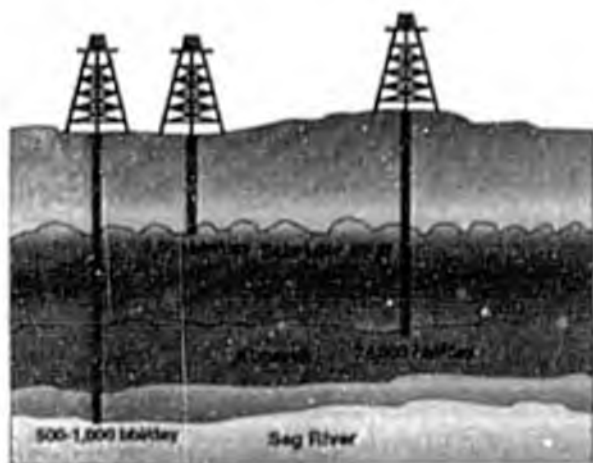


Chart 4

OXY

Milne Point produces 28,000 barrels of oil daily from three formations (*Chart 4*):

Kuparuk (24,000 bbl./day).

Kuparuk production has been the unit's mainstay since production commenced in November, 1985.

With an American Petroleum Institute ("API") gravity of 22-24 degrees, Kuparuk oil's quality is slightly heavier than other principal ANS crudes.

Sag River (500-1000 bbls./day). In 1995, an initial long, horizontal well was drilled into this deepest of Milne Point formations. The well has produced only 500-1000 bbl./day because of the extraordinary amount of water produced from the formation. The API gravity of Sag River oil is about 35 degrees; and

Schrader Bluff (3,000 bbl./day). Current production from this formation's heavy oil reserves comes from a pilot project initiated in 1990. The API gravity of Schrader Bluff oil ranges from 14-20 degrees. The companies' efforts to overcome the roadblocks to development of this resource are discussed in subsection (D), *post*.

B. The Unit's Economic Setting.

In-and-of itself, development of Schrader Bluff's heavy oil is a marginal proposition. Compounding the challenge is the fact that the unit from which that oil would be produced has been plagued by economic difficulties since its inception, including:

- Ø *Low Production Rates.* When Prudhoe Bay began production, its wells yielded up to 25,000 bbls./day. Initial rates from Milne Point's most productive formation--the Kuparuk--averaged only 862 bbl./day, and daily well production has declined at an annual rate of 15-20% ever since. Milne Point, in fact, has the lowest per well production rates of any major unit on the North Slope;
- Ø *High Royalties.* Because of a special royalty surcharge imposed on eight Milne Point leases at the time of unit formation (see Appendix A), BP pays a 20% royalty on its 91.19% interest in those eight leases. Virtually all other ANS production, including OXY's share of Milne Point production, is subject to a 12.5% royalty;
- Ø *High Transportation Costs.* As Chart 5 illustrates, Milne Point oil must travel through three pipelines to reach tidewater at Valdez, and resultantly pays the highest

Getting Heavy Oil to Market is Expensive

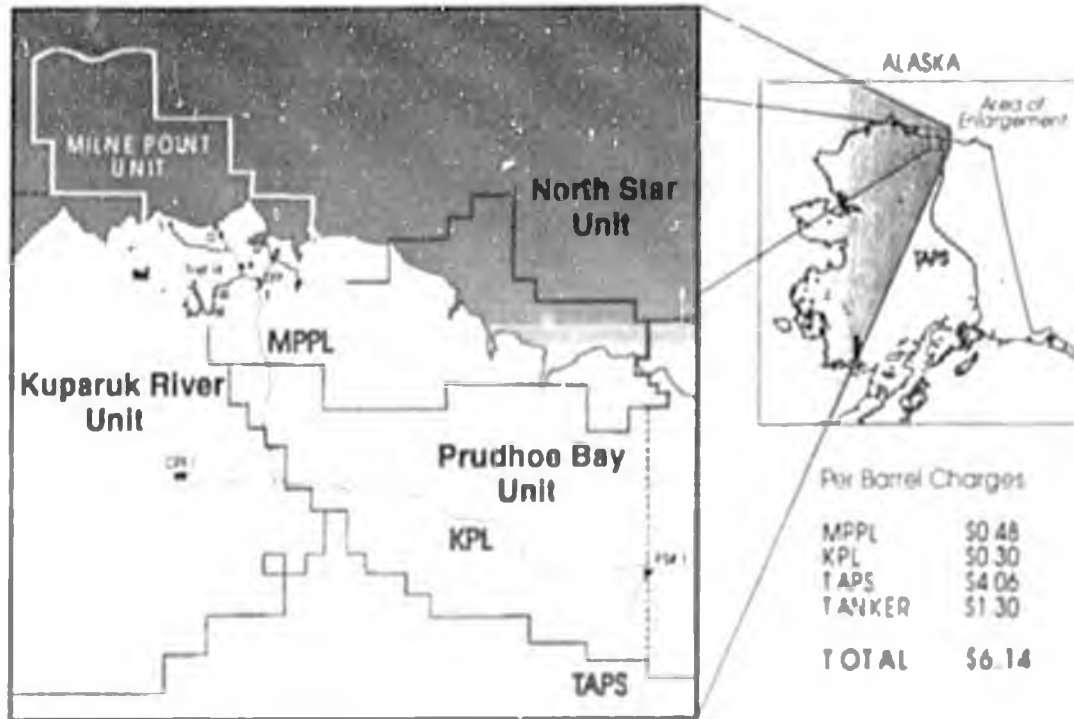


Chart 5

transportation costs on the North Slope BP shares in those pipelines revenues; however, and except for an 8.81% interest in the Milne Point pipeline. OXY does not. Any income that OXY earns from its North Slope endeavors must come from Milne Point wellhead revenues, and

o Production Challenges. Even Kuparuk Formation production has required costly waterflooding from the outset of production.

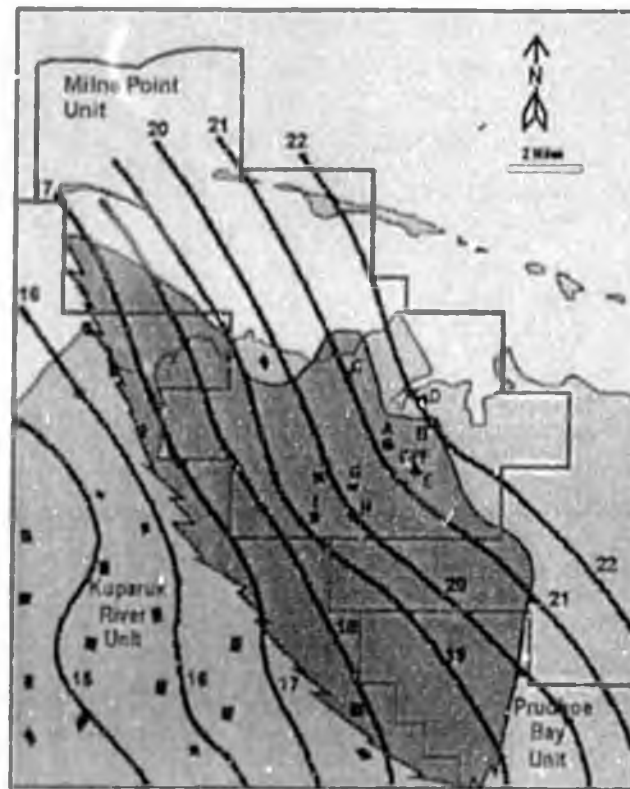
It is within this economic environment that BP and OXY have faced the challenge of developing the unit's heavy oil resources

C. The Difficulties of Producing Heavy Oil.

The thickness, or viscosity, of crude oil is related to its gravity--the lower the gravity number, the heavier and thicker the oil. Outside of Milne Point, Alaska's currently-produced crudes range from 22-30 degrees at Prudhoe Bay to 25-35 degrees at Cook Inlet.

"Heavy oil" is generally defined as crude oil with an API gravity of 20 degrees or less.⁷ As Chart 6 shows, the North Slope's heavy oil resources range from less than 14 degrees in the Kuparuk River Unit to 20 degrees in the southeast corner of the Milne Point Unit.

Thick as it is, heavy oil stubbornly resists lifting, and both downhole stimulation and mechanical lifting techniques are invariably needed to bring the oil to the surface. Compounding the problem on the North Slope is



SCHRADER BLUFF
O Sand
API Gravities

Chart 6

⁷ For example, the Internal Revenue Code allows companies to claim a favorable percentage depletion allowance for "heavy oil" production, which the code defines to include oil with an API gravity of 20 degrees or less. 26 U.S.C. 5613A(c)(6)(F). And, the U.S. Department of Interior, Bureau of Land Management, employs a 20-degree threshold for its pending heavy oil royalty relief proposal. 60 *Federal Register* 31663 (June 16, 1995).

reservoir temperature. At depths of 5000 feet or less, the cold Arctic subsurface chills the oil to impractically low temperatures.

Moreover, in Schrader Bluff's case the heavy oil is entrained in unconsolidated sand. As the oil is lifted, sand comes with it, choking the well bore and fouling the well pump.

Heavy oil's specific gravity is close to water's; as a result, oil/water separation becomes especially difficult. Once separated, moreover, heavy oil's viscosity, and its relative paucity of more valuable lighter hydrocarbon fractions, makes heavy oil less valuable in the market.

Heavy oil wells are notoriously slow producers. And though heavy oil fields enjoy correspondingly long field lives, slow initial production rates considerably impair the investor's ability to recover its capital investment in a commercially reasonable time.

Schrader Bluff's heavy oil is thus triply disadvantaged: (1) it shares the unpleasant attributes of heavy oil generally, (2) the reservoir's shallow depth and unconsolidated sand impose yet additional engineering challenges, and (3) its development suffers all the economic handicaps facing Milne Point as a whole.

Even so, Alaska's North Slope lessees have invested hundreds of millions of dollars trying to make a go of this uncooperative resource.

D. Industry's Efforts to Develop ANS Heavy Oil.

The initial stab at ANS heavy oil came not at Milne Point, but rather at the adjacent Kuparuk River Unit, which is operated by Arco Alaska Inc. ("Arco"). The prize at Kuparuk River is potentially even greater than Milne Point's. While Schrader Bluff

might produce 300 million barrels of heavy oil. Kuparuk River's West Sak Sands could eventually produce two or more times that amount.

Beginning in September, 1984, Arco invested \$135 million drilling 13 wells into the West Sak Sands, and building associated facilities, before abandoning that pilot project in December, 1986. About 1 million barrels were ultimately produced from that endeavor, which meant that the project's development costs were about \$135/bbl.

It took industry five years to try again, this time at Schrader Bluff. At Milne Point's Tract 14, Conoco, Chevron and OXY invested about \$126 million on 22 heavy oil wells and associated facilities.⁷ The project's expected recovery of at least 13.5 million barrels translates into a 15-fold improvement in per barrel investment costs over Arco's West Sak effort—from \$135/bbl to \$9.30/bbl.

The Tract 14 pilot was an exercise in ingenuity. To keep sand from the wellbore, the companies installed special gravel filters. To heat the oil as it rose through the permafrost zone, heat trace elements were wrapped to the production tubing. The reservoir was fractured to stimulate production, and an electric submersible pump was added downhole to lift the oil. *Chart 7.*

⁷ Conoco, Chevron and OXY brought considerable expertise to bear on the 1991 pilot project. OXY, in particular, has long been a leader in developing innovative lifting techniques for heavy oil, particularly in California, where OXY owns heavy oil properties.

Even so, development costs of \$9.3M/bbl still made the exercise uneconomic, and initial flow rates from Tract 14 wells only averaged 275

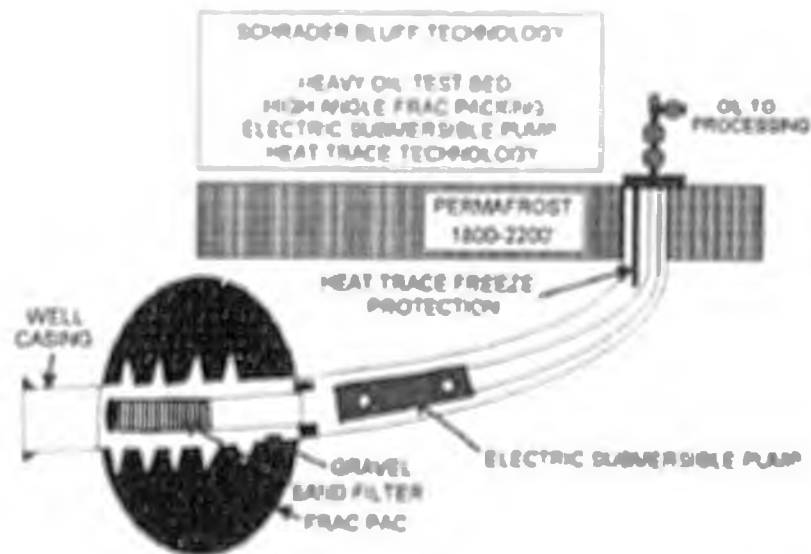


Chart 7

bbls/day. And so, at the end of 1991, further development of Schrader Bluff stopped.

It resumed again in 1994 with BP's acquisition of majority ownership in the unit. One heavy oil well was drilled in 1994, and, in 1995, BP and OXY invested \$15 million in six new wells, some well recompletions and additional technical study.

While evaluation of the 1995 drilling isn't complete, we do know that

- o Advances in technology and better geologic information have made initial flow rates of 300-400 bbls/day practical, and
- o Other, more conventional methods of stimulating heavy oil production are impractical. Conoco began water injection into Schrader Bluff wells in 1992, without proven success to date. Horizontal drilling, which improves lifting, has been tried at Schrader Bluff with mixed results. Steamflooding, a common recovery technique in the Lower 48, isn't feasible on the North Slope for environmental and practical reasons.

Experience thus suggests that any dramatic technological breakthrough that would greatly improve ANS heavy oil well productivity is unlikely in the foreseeable future. Put simply, engineering, while it has brought full development of Schrader Bluff

near the brink, may also have reached the point of diminishing returns. What happens from here is largely an economic question.

And it's a question worth pursuing, given the considerable benefit, to both the public and private sectors, of realizing the fullest possible return on heavy oil development.

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III. The Consequences of Schrader Bluff Development

Ultimately, BP and OXY expect to recover at least 13.5 million barrels of heavy oil from the Tract 14 pilot project. Conversely, underlying Milne Point are about 300 million barrels of reasonably recoverable heavy oil. As one might expect, development of that resource would resonate throughout Alaska's economy.

A. The Parameters of Development.

DNR's Spring, 1995 production forecasts for Milne Point portray a unit peaking at 65,000 bbl/day

in 1999, then sharply

declining until the unit is

abandoned in 2011.¹⁷ As

Chart 8 illustrates, with

development of Schrader

Bluff's heavy oil, the unit's

profile looks different.¹⁷

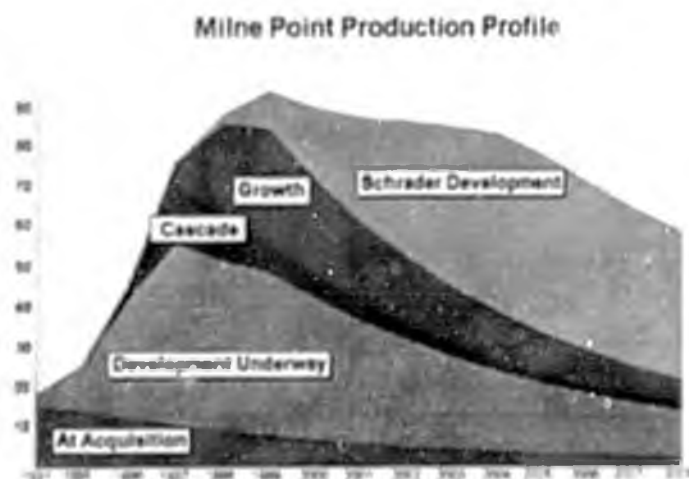


Chart 8

¹⁷ Historical and Projected Oil and Gas Consumption, March, 1995 at 6-7

¹⁷ The components of Milne Point production depicted in the chart include: (1) "At Acquisition." This component reflects Milne Point production existing when BP acquired majority ownership of the unit at the end of 1973. (2) "Development Underway" is principally comprised of additional Kuparuk formation production from the northwest corner of the unit. (3) "Cascade" refers to an accumulation lying to the southeast of the unit. Production from that lease will be routed through Milne Point's processing facilities. (4) "Growth" refers to a number of planned expansion projects, and (5) "Schrader Development," of course, refers to the unit's heavy oil resources. Without Schrader Bluff development, the companies project peak production in 1998-99 of about 80,000 bbl/day--a forecast more optimistic than DNR's projections. Milne Point's central processing facilities are being expanded to accommodate that increased production. Currently, the unit produces only 28,000 bbl/day--a limit dictated in part by the current capacity of the unit's processing facilities. On the other hand, the companies' forecasts do mirror DNR's projections of a sharp decline in unit production after 1999, absent development of Schrader Bluff.

It and when the project becomes commercially feasible, the Milne Point Unit business plan envisions that initial development of Schrader Bluff would involve drilling some 230 wells, and constructing new surface facilities and pads, over a nine-year development period, with a total capital cost of \$550 million. Once producing, those wells would peak at 45,000 bbls./day, and production would decline only gradually, giving the field a 41-year life.

Over the 41-year period, production expenses would average \$15 million annually, totalling \$600 million over the field's life.

B. The Economic Impacts of Schrader Bluff Development.

1. Private Sector Employment

The University of Alaska Anchorage has authored an economic impact analysis of the initial development scenario in the Milne Point business plan. ¹⁷ Employing the impact methodology developed by Professor Scott Goldsmith, the analysis charted both the direct and indirect employment and fiscal consequences of Schrader Bluff development. Looking first at the development phase of the project, those impacts included:

Ø 233 direct oil industry jobs created during the nine-year development phase. ¹⁷ Of those jobs, 157 would be performed in Alaska, and 118 would be filled by Alaska residents;

Ø 142 indirect or spin-off Alaska private sector jobs, and an additional 62 jobs for Alaska industry vendors, created during the development phase alone;

¹⁷ The analysis, entitled "*Heavy Oil Development: The Economic Impact*," is available on request from either UAA or BP.

¹⁷ For the development phase, the UAA report expresses its projections in "man-years of employment" for the entire nine year development phase. To translate that number into "jobs," the total man-years (in the case of direct industry jobs, 2098 man-years) was divided by nine.

- Ø *All tolled, 322 new private sector jobs filled by Alaska residents during the development phase, out of a total of 361 new private sector jobs performed in Alaska; and*
- Ø *An Alaska resident payroll of \$171 million during the development phase, out of a total Alaska payroll of \$206.5 million.*¹⁷ *Because Milne Point is a remote location, and because the jobs created by Schrader Bluff development are skilled, the average salary for each new direct oil industry job would be \$100,000/yr.*

Because the core infrastructure is already in place at Milne Point, the impacts of development-related employment would begin to be felt within months of the companies' commitment to the endeavor. Potentially, if that commitment is made early enough in 1996, the resultant jobs and payroll during the development phase would fuel the Alaska economy from 1996 through 2004.

Enhanced production would then commence in 1997. From that year, and until the year 2037, the UAA analysis projects that, throughout the period, Alaska would experience:

- Ø *58 new long-term direct oil industry jobs in Alaska, of which 46 would be held by Alaska residents;*
- Ø *An additional 76 new indirect and vendor jobs created in Alaska;*
- Ø *All tolled, 134 new private sector jobs created in Alaska, of which 122 would be held by Alaska residents; and*
- Ø *A total Alaska resident, private sector payroll increase of \$7.43 million/year, out of a total Alaska private sector payroll increase of \$8.58 million/year.*

¹⁷ All dollar figures expressed in the UAA report are in constant 1995 dollars.

The private sector employment impacts forecast in the UAA report are summarized in Chart 9

Alaska Resident Private-Sector Jobs Created by Schrader Bluff Development

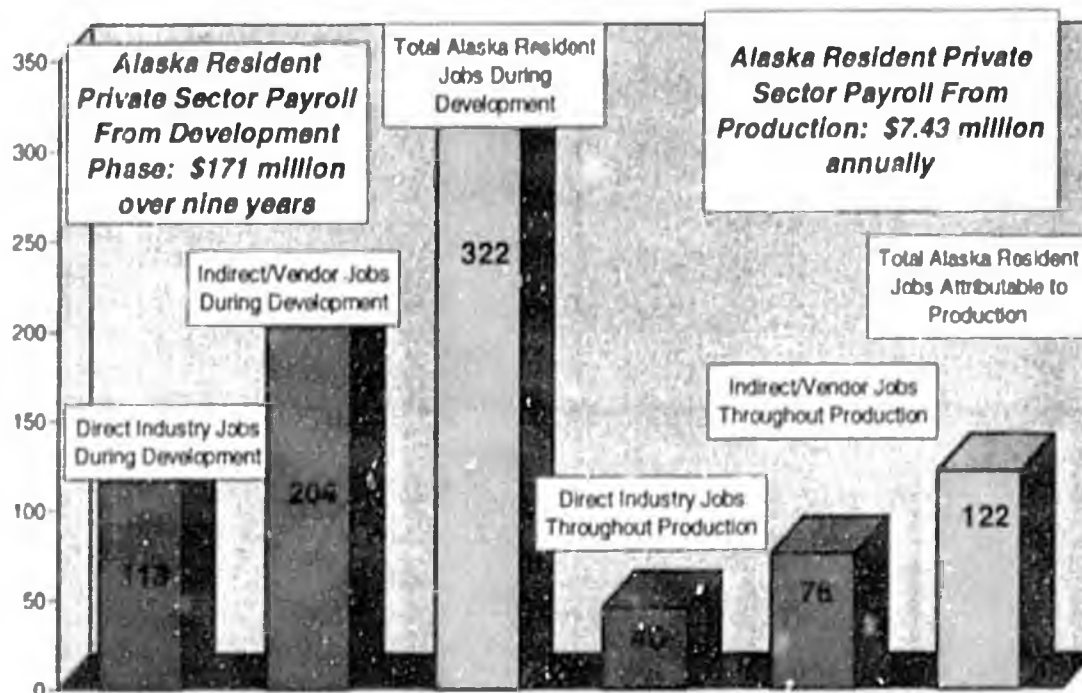


Chart 9

2. State Revenue Impacts

As Chart 2 indicates, the state can expect to receive \$365 million more in royalties than DNR's Spring, 1995 production forecasts would yield--if the passage of HB 325 stimulates development of Schrader Bluff.¹⁷ For its part, and as Chart 10 illustrates, UAA looked at the aggregate of royalty and tax revenues that the state could expect to receive from initial Schrader Bluff development. UAA projects that the state would receive \$444 million in revenues, and a \$348 million net return (after accounting

¹⁷ Again, the \$365 million figure is expressed in nominal dollars.

for increased government expenditures occasioned by the substantial increase in private sector employment), as a result of initial field development.¹⁷

One element of that net gain warrants special attention. Schrader Bluff development would cause a proportional increase in TAPS pipeline throughput occasioned by up to 45,000 bbl./day of

UAA's Projected State Revenues From Initial Development of Schrader Bluff, With a 5-Year Royalty Suspension
In millions of 1985 dollars

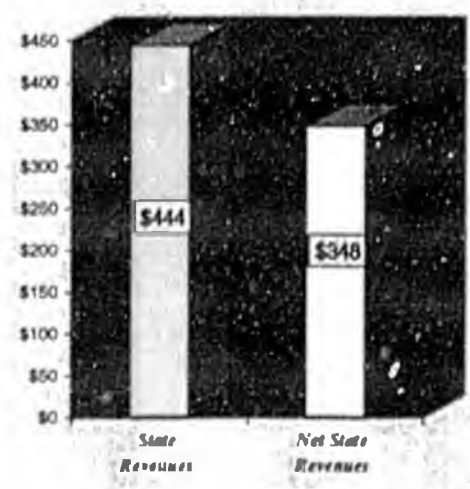


Chart 10

Schrader Bluff heavy oil travelling through it. Declining ANS production in the 21st century will cause upward pressure on per-barrel TAPS tariffs. As more Schrader Bluff oil passes through the TAPS line, the tariff on *all* ANS crude decreases, and the resultant wellhead value on *all* ANS crude increases.

That, in turn, results in higher state royalties on *all* ANS production. UAA estimates, in this regard, that if Schrader Bluff were developed, the state would earn between \$65-\$84 million in additional royalty income from *all* ANS production during Schrader Bluff's field life.

3. Public Sector Employment

UAA projects that the economic activity generated by Schrader Bluff development will occasion \$97 million in public sector costs over the life of the field. To a large extent, that translates into new public sector jobs.

¹⁷ If TAPS pipeline throughput were lower than that scenario envisions, UAA's revenue and net revenue projections are, respectively, \$425 million and \$329 million.

UAA estimates that development will directly result in 27 additional state government jobs during the development phase, and an additional 10 state jobs lasting over the field's 41-year producing life. UAA also believes that second and subsequent rounds of public sector employment gains will be realized as the economic impact of the enterprise compounds itself. UAA concluded that 38 additional new public sector jobs--state and local--would be spawned by this multiplier effect during field development, while 15 additional new public sector jobs would be generated by the multiplier effect throughout 41 years of field production.

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IV. The Economics of Schrader Bluff Development.

A. The Rate of Return Necessary for Schrader Bluff Development.

\$550 million--the capital necessary to develop Schrader Bluff--is a considerable investment. And as Arthur D. Little recently reminded the Oil & Gas Policy Council, "[c]ompanies will review and compare all opportunities available to them worldwide, [and] governments are competing on a global basis to attract risk investment."¹⁷

The benchmark by which the attractiveness of Schrader Bluff investment will be measured is the "hurdle rate," which represents the minimal projected rate of return necessary to warrant consideration among the companies' investment options. That rate, in turn, is built on four components (Chart 11):

"Hurdle Rate" -- The Minimum Rate of Return Necessary to Justify Capital Investment



Chart 11

- o *The cost of capital.* Corporations acquire investment funds in one of two ways--borrowing, or attracting equity investment. The cost of capital is the weighted average of the company's bond interest rates and cost of equity.¹⁸
- o *Overhead.* Any new investment must bear its requisite share of the corporation's overall overhead costs, such as corporate management.

¹⁷ Little Report at 9.

¹⁸ Marino, *Handbook of Capital Expenditure Management* at 93 (1986). The cost of equity capital includes more than just dividends paid. The cost of capital for common stock, for example, consists of "the expected total return from dividend yield and capital gains." Block and Hirt, *Foundations of Financial Management*, App. 11A (1989); emphasis added.

Ø Risk. "[I]n order for investors to take more risk they must be compensated by larger expected returns...U.S. Treasury bills may be considered a riskless asset. When viewed in this context, an investor must achieve an extra return above that obtainable from a Treasury bill in order to induce the assumption of more risk." ;²⁰ and

Ø Profit. No enterprise invests without the expectation of some profit.

in today's market, and as Chart 11 suggests, these four "hurdle rate" components combine to require at least a 15% projected rate of return from any new investment--a benchmark validated by the *Little Report*:

Companies will generally consider any field uneconomic if the gross project value is negative at a discount rate of about 15%.

...
[Oil] companies generally look for a rate of return of about 15%...Projects with lower returns usually do not generate enough profits to encourage companies to commit time and resources to their development.

Little Report at 120, 122.

Passing the hurdle rate does not guarantee investment capital because, as Arthur D. Little reminded us, any investment must still compete with often lucrative worldwide opportunities. The hurdle rate is a qualifying time, not a checkered flag--it is only enough to warrant the prospect's consideration by corporate policy-makers.

The hurdle rate is therefore a conservative measure of Schrader Bluff's prospects, and also a conservative measure of the effectiveness of any development incentive.

²⁰1 *Foundations of Financial Management*, op. cit. n. 19; see also *In the Matter of the Filing of Revised Tariffs by Cook Inlet Pipeline Co.*, Alaska Public Utilities Commission, January 14, 1985 at 26 (additional rate of return allowed because of risk that oil prices may drop in the future).

B. Schrader Bluff's Projected Rate of Return.

To forecast the likely rate of return from Schrader Bluff development, OXY seems the fairest candidate since, unlike other North Slope producers, OXY's revenues from Schrader Bluff production will come solely from wellhead revenues--OXY does not share in significant downstream pipeline, tanker or refinery profits.

For its presentation to the Oil & Gas Policy Council in June, 1995, OXY projected its rate of return from something of a best case. For example, initial flow rates from the Tract 14 pilot project have averaged only 275 bbls./day. The five best of those 21 wells managed initial rates of between 300-600 bbls./day, and OXY's projections assumed initial flow rates equal to the average of *only those five best producing wells*.

In other words, OXY assumed that the technological innovation and better geologic data gained through five years of experimentation at Schrader Bluff would yield the highest plausible reward.

To those production forecasts were applied:

- Ø Projected oil prices drawn from the Department of Revenue's Spring, 1995 base case revenue forecasts;¹⁷*
- Ø Well costs equal to the average costs of Tract 14's 21 wells;*
- Ø The existing 12.5% state royalty, and historically-based tax payments;*
- Ø Projected operating expenses taken from the unit's 1995 estimates; and*
- Ø Facilities costs from the operator's 1995-1997 business plan.*

¹⁷ As noted previously, the Fall, 1995 Department of Revenue long-range price forecasts are virtually identical to the Spring, 1995 forecasts. See n. 5, *ante*.

The results are depicted in Chart 12. In short, the projections show a:

- Ø 12.8% projected rate of return. The projection thus falls materially short of the 15% hurdle rate;

Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14

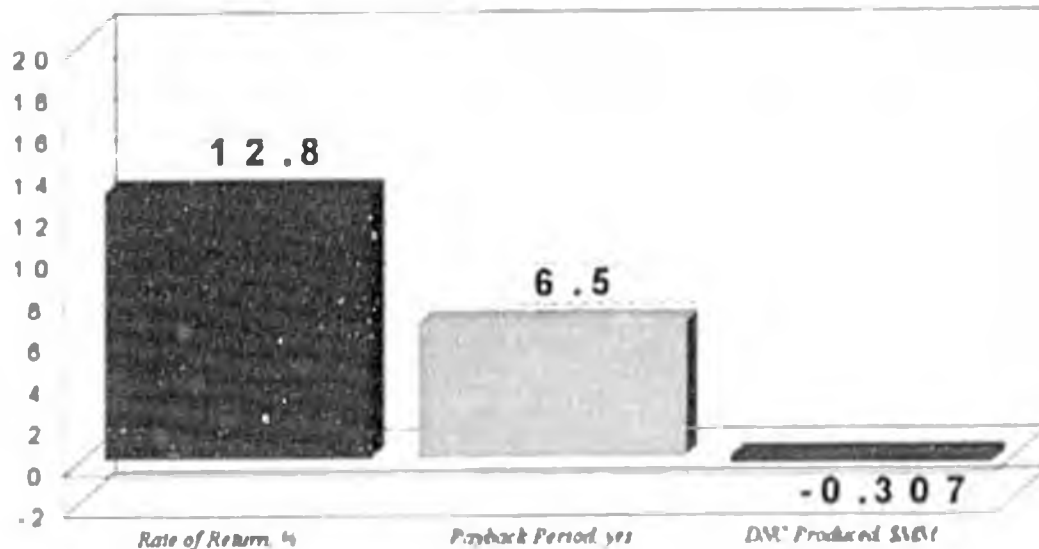


Chart 12

- Ø 6.5-year payout period. Five years is a commercially reasonable time for project payout. The extended payout period is a function, of course, of the inadequate rate of return; and

- Ø Negative discounted cash flow at 15%. As Arthur D Little observed, "[c]ompanies will generally consider any field uneconomic if the gross project value is negative at a discount rate of about 15%."

The numbers shouldn't be surprising. As we've seen, the state itself has long felt that development of Schrader Bluff is unlikely. And, despite

⇒ Arco's investment of \$135 million in the Kuparuk River Unit's West Sak sands.

⇒ Conoco's and OXY's investment of \$126 million in the Tract 14 pilot project; and

⇒ BP's investment of an additional \$15 million in pilot drilling, recompletions and technical studies in 1995.

the only heavy oil produced today on the North Slope flows from those limited experimental endeavors. Schrader Bluff heavy oil sits beneath a convenient unit infrastructure. And, as Chart 8 illustrates, full Schrader Bluff development is integral to prolonging the entire unit's economic life. There seems, in sum, no good reason for not developing that field, save for its inability to cross the hurdle rate threshold.

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V. *Legislation to Improve the Economics of Developing Alaska's Heavy Oil Resource*

A. *The Criteria for Legislation.*

Development of Alaska's heavy oil resource is a shared challenge. For its part, the private sector has invested nearly \$270 million over the past decade in a determined effort to increase production and reduce production costs.

For its part, the state will affect heavy oil investment decisions most directly through the royalty structure that it imposes. In tailoring that structure to optimize the public's return on heavy oil development, there are seven criteria that should shape the outcome:

- o *Specificity. As Section III(C)-(D) discussed, ANS heavy oil development presents unique challenges that are best met by a royalty structure tailored to the peculiarities of the resource. Revisiting general state royalty policy in order to spur heavy oil development may yield a result that is overbroad or insufficient, or which risks unintended consequences elsewhere.*

For example, last year the legislature rewrote Alaska's general policy on oil and gas royalty relief. Ch. 85, SIA 1995, HB 207. From a statewide perspective, the legislation set a positive tone for encouraging public/industry partnerships in developing Alaska's marginal reserves. However, the heavy oil initiative that may best suit development of that resource—a five-year royalty suspension—would be impossible under that legislation. HB 207 requires a minimum 5% royalty for every year of production from new fields,¹⁷ and a new field is eligible for relief only if there has been no commercial production from that field.¹⁸

Both of these limitations may make considerable sense generally. However, with respect to heavy oil especially, the

¹⁷ AS 38.05.180(j)(4)(A).

¹⁸ AS 38.05.180(j)(4)(B). As we have seen, about 3,000 bbls/day of heavy oil are produced and sold from Schrader Bluff's Tract 14 pilot project.

minimum royalty requirement of HB 207 fails to account for the fact that heavy oil wells invariably: (1) have low initial production rates; but (2) produce for an unusually long time. Thus, the state may--and in this case apparently will--benefit more from a royalty structure that assesses 12.5%-20% royalties commencing in the sixth year of production, than from a structure that imposes, say, a 5% royalty throughout field life. See Section VI(C)(6-7), post. ¹⁷

- *Relevancy.* The task here is to materially improve the projected rate of return from the considerable capital investment necessary to develop ANS heavy oil reserves. Some royalty initiatives are aimed at lowering operating costs in order to prolong or renew production from declining wells. ¹⁷ Here, the targets are quite different: (1) improving the return on new investment; and (2) reducing the period for recovering that investment to a commercially reasonable one.
- *Certainty.* Companies are unlikely to make serious investment decisions on the mere possibility of a favorable royalty structure. A royalty structure established by operation of law, rather than one dependent on the uncertain outcome of an administrative proceeding, is considerably more likely to favorably influence investment choices.
- *Immediacy.* There is a window of opportunity for development of ANS heavy oil reserves--one that will last only so long as: (1) the current infrastructure at Milne Point and Kuparuk River remains operational; and (2) the TAPS line is able to carry heavy oil at reasonable per-barrel tariffs.

DNR has projected, as recently as March, 1995, that Milne Point will be abandoned in 2011. That does not mean, however, that Alaska has 15 years to debate heavy oil. For example, integral to the ultimate economic viability of heavy oil development is the assumption that, over a considerable portion of heavy oil field life, production costs can be shared

¹⁷ The relationship of HB 207 to the issues raised by this paper is discussed further in Appendix A.

¹⁷ This, for example, is the purpose behind ULM's proposed heavy oil royalty regulations. Those regulations, which would establish a sliding-scale royalty for heavy oil wells, are intended to "place marginal or uneconomical shut-in oil wells back in production, provide an economic incentive to implement enhanced oil recovery projects, and delay the plugging of these wells until the maximum amount of economically recoverable oil can be obtained from the reservoir of field." 60 *Federal Register* at 14061 (April 10, 1995).

with other, conventional oil production from the same unit. And, as discussed in Section I, ante, the current momentum that has driven the 1994-95 pilot drilling and technical studies at Milne Point risks being lost if the project's economic prospects remain discouraging:

- Ø *Credibility.* Simply put, Alaska should look to initiatives that have proven successful in spurring capital investment in marginal fields in other oil producing jurisdictions.
- Ø *Sufficiency.* No one can guarantee the impact of any development initiative. On the other hand, if it is apparent that a given proposal would leave project economics below the competitive threshold, there is nothing gained by the exercise--and perhaps considerable to lose.
- Ø *Necessity.* The state should entertain economic incentives only if it concludes that the initiative will yield the state, and the public, a net economic benefit. Inherent in that philosophy is the proposition that the state should do no more than is reasonably necessary to induce the targeted activity. The state, in short, should not leave money on the table.

B. The Proposed Initiative--A Five-Year Royalty Suspension on New Heavy Oil Wells.

This paper, and HB 325, propose that the state suspend royalties, for the first five years of production, on the first 500 barrels of heavy oil produced from each new heavy oil well drilled on Alaska's North Slope after June 30, 1996.

The essential attributes of the proposal include:

- Ø *The Five-Year Suspension.* The suspension would be applied separately for each new heavy oil well drilled. When each well achieved five years' production, full lease royalties--at either 12.5% or 20%--would apply to all future production from that well.

Because new heavy oil wells would be drilled over a nine-year development period, there would thus be no sudden shift from royalty-free to royalty-burdened production. Rather, field royalties would be phased in beginning in the sixth year of development, as Chart 13 illustrates.

ADDITIONAL PRODUCTION FROM HEAVY OIL
BY
DEVELOPMENT YEAR

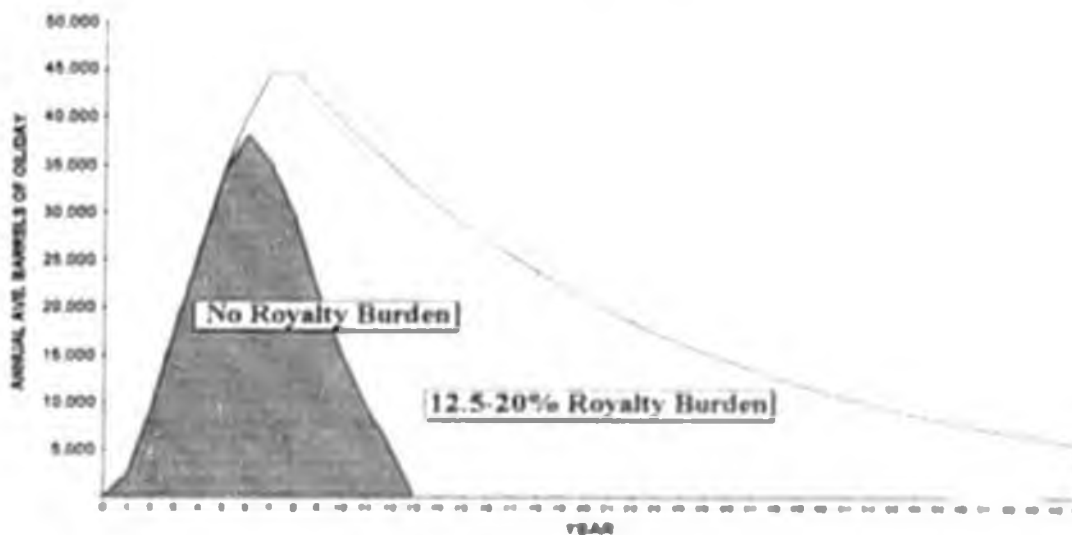


Chart 1.3

The five-year limitation coincides with the period that most investors consider the longest reasonable time to recover capital costs.

- o *The 500 bbls./day limitation. 500 barrels per day is as good a working definition as any of a marginal Alaska North Slope oil well. If a new ANS heavy oil well is able to achieve production in excess of that ceiling, that additional production would be subject to full lease royalties.*

ANS experience suggests that new heavy oil wells probably won't reach this ceiling. Even initial production rates from Schrader Bluff's Tract 14 wells averaged only 275 bbls./day, and the five best Tract 14 wells on which OXY's economic forecast, discussed in Section IV, was premised, averaged about 430 bbls./day.

- o *The Limitation to New Wells. The purpose of this initiative is to encourage additional development of ANS heavy oil reserves. As a result, the proposal does not affect production from any now-existing well, nor does it affect even new production from other formations such as Kuparuk or Sag River.*
- o *The Geographic Limitation to the North Slope. The economic and technical conditions on which the proposal is based are unique to Alaska's North Slope.*

C. Application of the Seven Criteria to the Proposed Royalty Suspension.

Among any number of possible royalty structures, the five-year royalty suspension seems to best satisfy each of the seven criteria discussed in subsection (A):

1. The Specificity Criterion

The technical and economic challenges facing development of ANS heavy oil are unique, and by confining the proposal's scope to new heavy oil wells on the North Slope, legislation can be carefully tailored to those peculiarities.

Through that kind of specificity, the proposal addresses one of the drawbacks of Alaska's fiscal system noted in Arthur D. Little's report to the Oil & Gas Policy Council. Alaska, until now, has maintained a one-size-fits-all royalty structure. On the one hand, Little found that this system has been good to companies producing large, profitable fields--indeed, Alaska ranks in the top quarter of oil producing jurisdictions worldwide in that respect. *Little Report* at 150.

On the other hand, Alaska's uniform system ranks poorly in encouraging investment in marginal fields. *Id.*

Little's findings prove the obvious: when setting statewide policy, the legislative and executive branches are inevitably driven by the policy's impact on large fields such as Prudhoe Bay. The specific proposal envisioned in this paper avoids that, and enables Alaska to take a more surgical approach to royalty policy.

2. The Relevancy Criterion

According to Arthur D. Little, Alaska's fiscal regime "is not fiscally efficient," and in fact ranks 48th out of 101 fiscal systems studied worldwide in its impact on field

rate of return. *Little Report* at 10, 150. "The Alaskan terms," moreover, "do not provide any incentive for the development of marginal fields." *Id.* at 172.

The reason is this: Alaska demands money up-front, before the field recovers its capital investment, irrespective of the impact of that demand on the field's ability to recover its investment within a commercially reasonable time. *Id.* at 91 ("A single royalty rate," Little concluded, "can make marginal fields uneconomic to develop.")

By suspending royalties at the outset of production, rather than spreading a reduced royalty over the field's life, the proposal targets the critical capital recovery period, which Little found Alaska to have heretofore ignored.

Moreover, and as Chart 13, *ante*, illustrates, given the typical production profile of a heavy oil well, targeting initial capital recovery, instead of spreading relief over field life, benefits the state as well. Because production will be initially low, but sustained over an extraordinarily long period with an unusually gradual decline rate, the state can expect to receive full lease royalties for a majority of total well production.

3. The Certainty Criterion

The proposal requires no application or agency review. The suspension is imposed by operation of law upon the occurrence of objectively-measured events.

4. The Immediacy Criterion

The suspension will be immediately available for any new heavy oil well drilled on the North Slope after June 30, 1996. And, at least at Schrader Bluff, industry is capable of responding to the initiative quickly. Because the infrastructure necessary for additional Schrader Bluff development is in place, additional heavy oil drilling could begin within months of the proposal's enactment.

5. The Credibility Criterion.

Royalty suspensions, Arthur D. Little concluded, "will encourage field development," and are "particularly effective for marginal fields" when they are tied to specific amounts of production. *Little Report* at 192. As the following table indicates, production tax and royalty suspensions have served as a principal tool for oil producing jurisdictions seeking to encourage investment in marginal properties:²⁷

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²⁷ Most oil producing states do not themselves own significant oil-producing property, and thus the production or severance tax is the principal source of those states' take. As a result, suspensions enacted in other states generally apply to the severance tax, rather than to privately-collected royalties.

Production Tax and Royalty Suspensions in Other Jurisdictions

<u><i>Jurisdiction</i></u>	<u><i>Investment Targeted</i></u>	<u><i>Length of Suspension</i></u>
<i>United States</i>	<i>Gulf of Mexico deep-water wells</i>	<i>Variable, depending on water depth</i>
<i>Texas</i>	<i>High-cost gas wells</i>	<i>10 years</i>
<i>Utah</i>	<i>Wildcat wells</i>	<i>First 12 months</i>
<i>Utah</i>	<i>Development wells</i>	<i>First 6 months</i>
<i>Oklahoma</i>	<i>Horizontal wells</i>	<i>Until payout</i>
<i>Oklahoma</i>	<i>Enhanced oil recovery projects</i>	<i>Until payout</i>
<i>Montana</i>	<i>Horizontal wells</i>	<i>First 18 months</i>
<i>Mississippi</i>	<i>Discovery wells</i>	<i>First 5 years</i>
<i>Mississippi</i>	<i>Re-activated wells</i>	<i>First 3 years</i>
<i>Kansas</i>	<i>Tertiary projects and shallow wells</i>	<i>Life of the project</i>
<i>Kansas</i>	<i>Discovery wells</i>	<i>First 12 years</i>
<i>Arkansas</i>	<i>Discovery wells</i>	<i>First 5 years</i>

According to the Texas Railroad Commission, its 10-year production tax suspension for high-cost gas wells netted that state, for the period 1989-93:

- Ø A 400% increase in the number of high-cost gas wells drilled annually in Texas above the number drilled annually before enactment of the incentive;*
- Ø \$4.122 billion more in natural gas produced in the state over the period;*
- Ø \$240 million in additional sales tax revenues generated over the period;*
- Ø 104,000 new additional employment years created over the period; and*

0 \$12 billion in additional economic value generated for the state of Texas over the period. ²¹

As originally enacted, the Texas incentive was to expire in 1996. Based on its fiscal track record, the Texas legislature renewed the incentive this past year for an additional six years.

6-7. The Sufficiency and Necessity Criteria

As Chart 14 indicates, the five-year, 500 bbls./day royalty suspension moves Schrader Bluff's rate of return from the 12.8% projected by OXY to 15.9%.

The Effect of Royalty Suspension on Schrader Bluff Development Decisions

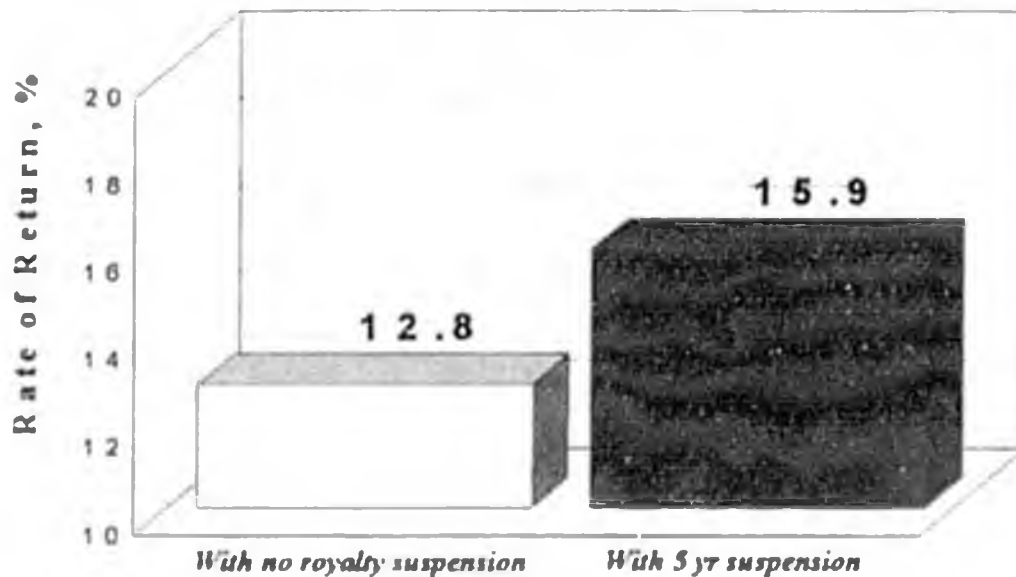


Chart 14

²¹ Source: Texas Railroad Commission. "Extension of Tax Incentive for the Production of Certain High Cost Gas." undated (1994).

Chart 15 shows that the suspension proposal also reduces the capital recovery period close to a commercially reasonable five years.

The Effect of Royalty Suspension on Schrader Bluff Economics

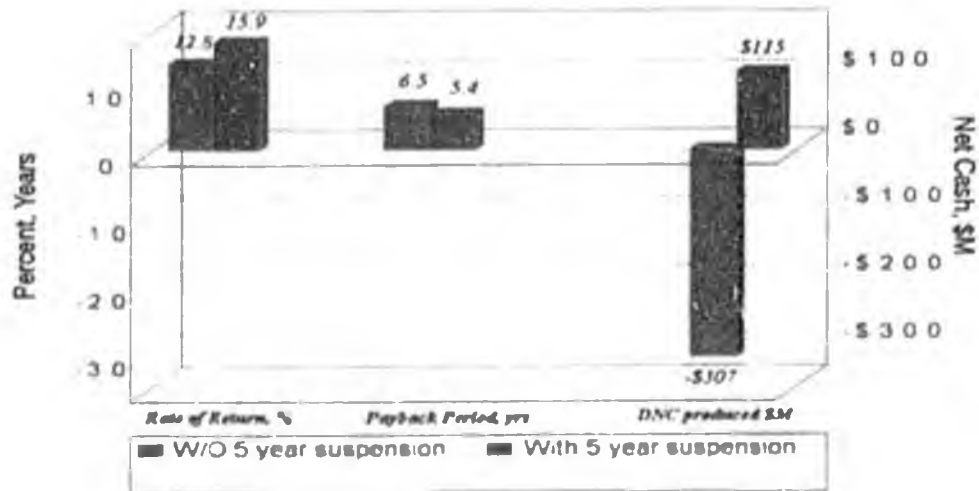


Chart 15

The five-year suspension thus seems *sufficient* to at least make Schrader Bluff development competitive with other industry investment opportunities. It appears to put that endeavor over the hurdle rate--an accomplishment that, as discussed *ante*, does not guarantee funding, but does lift the usually fatal burden of bearing below-hurdle rate economics.

It does so, however, by the thinnest of margins, suggesting that the proposal satisfies the *necessity* criteria as well. That's perhaps best illustrated by the \$115,000 positive net discounted cash flow projected on Chart 15, which is presented on a per-well basis. With each new heavy oil well costing perhaps \$2 million, that \$115,000 translates into slightly more than a 5% profit for any given well

The suspension proposal's fit with the necessity criteria--that is, with the concept that the state should leave nothing on the table--can be seen in three other ways:

1. *Built-in safeguards.* The proposal's 500 bbls./day ceiling, for example, protects the state in the event that an engineering breakthrough enables heavy oil producers to pull more oil through new ANS heavy oil wells. If any technologically-driven windfall occurs during the suspension period, the state will receive full lease royalties from the added production.

Moreover, and by the very nature of the suspension proposal, the state is better assured a full share of any increased profits caused by either technology or unanticipated oil price increases. With full lease royalties commencing in each well's sixth year of production, the state's risk of losing its full share of any unanticipated profits ends after five years. Conversely, simply reducing the lessee's royalties over the life of the field--to, say, 5%--would expose the state to that risk for over 40 years. And, the consequence of that difference is magnified by the fact that both oil prices and the state of technology are more predictable in the short run than over a four-decade period.

Similarly, if enhanced recovery techniques ultimately allow more total production than is now estimated, the state would enjoy full lease royalties from that increased production, since it would occur later in field life.

2. *Comparison to Other Incentives.* As Chart 16 shows, a 5% royalty reduction on new heavy oil wells, extending over the life of each well, would also push Schrader Bluff development over the hurdle rate. On a nominal dollar basis, however, the state's royalties over the life of the field would be considerably less. Because of their low initial production rates and slow decline rates, heavy oil wells are better suited, from a landlord's perspective, to a finite royalty suspension at the outset of production than to a reduced royalty over the life of the field.

HB 325 Meets the Necessary and Sufficiency Criteria....

5 Year Royalty Suspension (HB 325) vs. 5% Royalty for the Well's Life

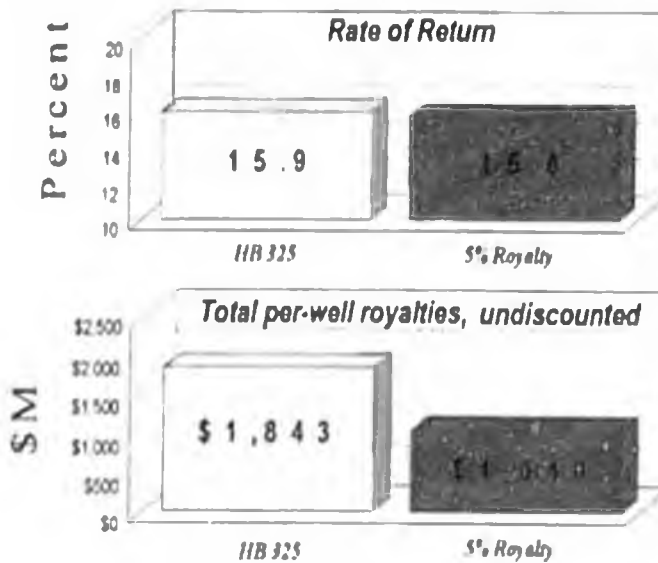


Chart 16

3. *Return to the State.* This paper began with Chart 2, which compared: (1) the \$60 million in royalties that the state could expect to receive from the limited Schrader Bluff production forecast by DNR in the Spring of 1995; to (2) the \$425 million in royalties that the state could receive from development of Schrader Bluff under the unit's business plan, even with a five-year royalty suspension.

The suspension proposal would thus seem to meet the essential test of a successful partnership--considerable net benefit to both partners.

For its part, industry has already contributed about \$270 million to that partnership through the Schrader Bluff and West Sak pilot projects. And most recently, BP won a \$1.6 million U.S. Department of Energy Grant--to which BP will add \$9 million--to further refine heavy oil recovery technology.

Moreover, if development occurs, BP and OXY will contribute another \$550 million capital investment, and on a project basis won't recover that investment for at least seven years. Thus, the state, which will begin receiving full lease royalties on initial wells at the beginning of the project's sixth year, will see a positive net cash flow from its heavy oil partnership sooner than will its industry partners.

VI. Conclusion

Some decision about Alaska's heavy oil reserves will be made this year--since, as we've seen, even a decision to do nothing carries its own risks, and ought to be a conscious choice, if that's the choice made. Indeed, waiting-to-see may present the highest stakes of all, since it is the only alternative that risks losing the entire resource.

Governor Knowles has provided a critical catalyst for this debate--a debate that, given the magnitude of the resource, warrants legislative involvement. And that discourse is likely to yield the best possible answer if it remains guided by three overriding issues:

- ◇ *Are Alaska's heavy oil reserves likely to be developed in the near future even without any stimulus on the state's part?*
- ◇ *If not, then do the benefits of immediate development, and the risk of waiting, warrant a special state/industry partnership to develop those resources now? and*
- ◇ *If immediate development is in the public interest, what form of royalty structure will best meet the seven criteria discussed in this paper?*

Irrespective of the outcome, the fact that the State of Alaska is about to have such a business-like discussion, as discussions between potential partners should be, sends an encouraging signal about the direction of Alaska's economic climate into the next century.

*Appendix A: Some Questions About the Heavy Oil
Five-Year Royalty Suspension Proposal*

Q: Why don't companies with heavy oil reserves simply use the process established last year in HB 207 (Ch. 85, SLA 1995).

HB 207 authorized discretionary royalty relief in three instances: (1) for new marginal fields; (2) to restore shut-in production; and (3) to prolong the economic life of older fields. A new field is eligible for relief only if "the field or pool has not previously produced oil or gas for sale." AS 38.05.180(j)(1)(C). About 3,000 bbls./day are produced from Schrader Bluff's Tract 14 pilot project. Schrader Bluff would thus be ineligible for "new marginal field" relief, and the remaining bases for relief under HB 207 are simply inapplicable.

For its part, Arco did produce and sell oil from its West Sak Sands pilot project at the Kuparuk River Unit, but has since abandoned that production. Arco, therefore, might be eligible for relief under HB 207 "to reestablish production of shut-in oil."

However, HB 207 imposes another barrier. As the white paper explains, a five-year royalty suspension at the outset of production seems better suited--from both industry's and the state's perspective--to spur additional heavy oil development than a reduced royalty over field life. HB 207, however, requires a minimum 3-5% royalty throughout the life of the field. AS 38.05.180(j)(4). Royalty suspensions, then, are categorically excluded under that legislation.

Of course, HB 207 could be amended. It shouldn't be, for these reasons:

1. As a general statement of state royalty policy, HB 207 sets a proactive tone for future state/industry cooperation in sustaining Alaska's oil and gas industry into the 21st century. It was landmark legislation in that respect--creative royalty management has long been discussed in Juneau, but there hadn't been much concrete action. HB 207 is an accomplishment that does not need revisiting;

2. On the other hand, HB 207 did not purport to solve every development challenge facing the state and the oil industry. That is why, for example, Governor Knowles charged his Oil & Gas Policy Council to address additional royalty management issues after the law had passed. Specifically, the state made a conscious choice, last session, to address heavy oil development separately through the Council and the responsible legislative committees; and

3. As discussed in the white paper, ANS heavy oil development presents unique economic and technical issues that are best addressed on their own. The terms and limitations in a general law such as HB 207 are sensible as a statewide rule--given the

myriad circumstances they will govern. However, and as Arthur D. Little suggested to the Oil & Gas Policy Council, one-size-fits-all policies, which were necessarily developed with larger fields in mind, may actually impair development of smaller or unusual fields. The peculiar challenges facing ANS heavy oil development are ample proof of that.

Lastly, resorting to discretionary agency relief would satisfy neither the certainty nor immediacy criteria that, as the white paper explains, are critical to stimulating heavy oil development during the current window of opportunity presented by existing unit infrastructures, reasonable TAPS pipeline tariffs, and the momentum occasioned by the Tract 14 pilot project and BP's 1994-5 drilling program.

Q. Milne Point already pays no severance tax because of the economic limit factor. Isn't royalty relief asking too much?

Arthur D. Little, in his report to the Oil & Gas Policy Council, concluded that Alaska's royalty structure was "fiscally inefficient," and particularly harmful to marginal fields, because it demanded high payments before a field could recover its capital investment.

For its part, Alaska's severance tax cures that problem, and becomes sensitive to field productivity, through the ELF. However, in the case of marginal endeavors such as ANS heavy oil development, the progressive policies of the severance tax are undermined by a regressive royalty policy. That fact argues for consistency between the two fiscal regimes. The current inconsistency is a problem, then, but for reasons other than the question suggests.

The white paper shows that, even with application of the ELF, development of Alaska's heavy oil reserves is unlikely to occur unless the state revisits its royalty structure for that resource--a fact corroborated by: (1) the industry's inability to develop the resource, despite investing \$270 million in pilot drilling; and (2) DNR's oil production projections. Whether royalty restructuring is "too much" of a price to pay to develop that resource is, of course, the ultimate question. Given, however, that:

(1) the state is likely to receive only \$60 million in royalties from Schrader Bluff production if DNR's production estimates prove true; while

(2) the state may receive \$425 million in royalties if the royalty suspension proposal is enacted, and development of Schrader Bluff's reserves resultantly occurs,

it would seem that the state would not be paying much of a price at all.

Q: OXY received a royalty reduction through a 1994 settlement agreement that restricted its right to apply for additional reductions from DNR. Isn't OXY's support of a royalty suspension an end-run around that agreement?

The 1994 settlement agreement returned OXY's Milne Point royalties to the same rate that the state had promised when OXY's predecessors acquired an interest in the Milne Point leases by competitive bid in 1969. The lease royalty rate was, and for OXY is now again, 12.5%.

Several years after acquiring those leases, Conoco (which was then the unit operator) and the other unit participants applied to DNR to form the Milne Point Unit. The state, however, informed the companies that it would not approve the unit agreement, and would allow the Milne Point leases to lapse, unless the companies agreed to increase the royalty on eight unit leases from 12.5% to 20%.

In late 1985, after oil prices had collapsed, the companies applied to DNR to reduce the unit's royalties. At the time, DNR believed that Milne Point warranted relief, especially given the unusually high 20% royalty that some unit production now bore, but also felt that that it was legally precluded from granting relief until the unit had produced oil for two years.

In January, 1987, the Milne Point Unit was shut-in--DNR having concurred that continued operation of the unit posed an unwarranted economic hardship.

Production resumed in April, 1989, and when two years' total production had been achieved in February, 1990, Conoco and OXY again applied for a reduced royalty. In two separate decisions issued on April 21 and 22, 1991, DNR denied those applications. Conoco and OXY then appealed those denials to Alaska Superior Court.
'/

The litigation lasted for over three years. In December, 1993, and after an unsuccessful eight-year effort to reach a royalty agreement with the state, Conoco sold its interest in Milne Point to BP Exploration (Alaska) Inc., as did Chevron.

OXY maintained its minority 8.81% interest in the unit, and in July, 1994 the litigation settled. OXY's royalties were returned to the same 12.5% rate that Alaska had promised OXY's predecessors back in 1969, when the leases were issued. The settlement, however, was personal to OXY. BP remained obligated--and remains obliged today--to pay a 20% royalty on its majority share of production from the eight affected leases.

Section 5.3 of the settlement agreement also restricted OXY's ability to apply to DNR for royalty reductions. That clause reads:

¹ Conoco Inc. v. State of Alaska, Department of Natural Resources, 11U-91-797Civ.; OXY USA Inc. v. State of Alaska, Department of Natural Resources, 11U-91-798Civ.

Notwithstanding paragraph 18(h)(8) of the MPU Agreement and any otherwise applicable law, OXY cannot apply for any reduced royalty: (1) for any of the [eight 20% leases]...during the remaining life of the MPU; or (2) for any other liquid hydrocarbon production from the MPU, for five years from the effective date of this agreement.

By both its terms and intent, the agreement does not attempt to limit the legislature's authority to set state royalty policy. Rather, this clause was inserted after both parties agreed that neither wished to reenact the 4 1/2 years of costly administrative proceedings, and subsequent litigation, consumed by these discretionary royalty reduction applications.

And in any event, the question is academic, because if HB 325 is enacted, the state will still enjoy the full benefit of its bargain. The proposal would apply only to new heavy oil wells drilled after June 30, 1996. DNR's production projections have, as recently as March, 1995, assumed that future Schrader Bluff production will be limited to the unit's pre-existing Tract 14 pilot project. Thus, HB 325 would not affect any production that DNR believed would occur when it entered into the settlement agreement in 1994.¹⁷

In the scheme of things, this question is tangential to the heavy oil debate--after all, OXY owns but an 8.81% interest in one heavy oil field. Moreover, one needs to remember that the initiative for this discussion came not from OXY, but from the state itself. OXY was invited to participate in the debate over state oil policy initiated by the introduction of HB 207 and creation of the Oil & Gas Policy Council, and it has always been forthcoming on this count in its discussions with both the administration and the legislature. OXY, like anyone, is subject to new laws, and it welcomes the opportunity to exercise its right to participate in public debate over oil and gas legislation.

¹⁷ Indeed, when the settlement agreement was entered into, DNR was not only projecting that no further development of Schrader Bluff would occur beyond the Tract 14 pilot project--it had concluded that the Milne Point Unit as a whole would be abandoned in the year 2006. DNR, *Historical and Projected Oil and Gas Consumption*, February, 1994 at 6-7.

Q: How can we be assured that, if this initiative passes, our heavy oil reserves will actually be developed?

As the white paper explains, improving Schrader Bluff's economic outlook will not guarantee a positive investment decision. It will only allow Schrader Bluff to compete with other investment opportunities. Actual funding is always a function of available budget funds, the quality of competing prospects, and other variables.

Industry, however, does have a considerable stake in following through. First, it has already invested about \$270 million in heavy oil pilot projects--an investment it would plainly like to recoup. Second, lessees with heavy oil reserves do feel some sense of urgency. They know that, given the right economic climate, ANS heavy oil reserves are more valuable now than perhaps they'll ever be. There is an existing on-site infrastructure now; transportation costs are tolerable; and the momentum spawned by the Tract 14 pilot project and BP's recent drilling provides a stimulus to additional development that may well evaporate in a climate of disinterest.

Successful development of North Slope heavy oil is dependent on industry's ability to increase production rates and lower production costs, and the state's interest in crafting a workable royalty structure. Section II of the white paper explains how industry is meeting its obligations in that respect, and by enactment of an effective royalty initiative, the state would have done all it can. In that event, heavy oil would not be lightly disregarded by industry.

Finally, one should remember that the royalty suspension would apply solely to new heavy oil wells drilled after June 30, 1996. If Schrader Bluff or other ANS heavy oil reserves aren't developed, the state loses nothing.

Q: Why isn't this just another industry giveaway?

Bear in mind, in this respect, that the state "gives" nothing unless industry contributes to the partnership by heavily investing in heavy oil development.

But, yes, if the state concludes that Schrader Bluff and the Kuparuk River Unit's West Sak sands will likely be developed while existing unit infrastructures remain operational; while TAPS tariffs remain reasonable; and while existing development momentum perseveres, then the royalty suspension proposal is a giveaway, and the state shouldn't do it.

Q: If OXY owns only an 8.81% interest in Schrader Bluff, why is it so interested in all of this?

To begin with, heavy oil is something of a cause celebre for OXY. It is a nationwide leader in developing creative methods for lifting heavy oil.

And Milne Point is OXY's core asset in Alaska. OXY is the only original Milne Point participant remaining, and its perseverance over 15 difficult years reflects a stubborn commitment to realizing that unit's full potential.

And frankly, that is all to Alaska's advantage. The gene pool of Alaska's oil industry is shrinking, and that's unhealthy. Conoco gave up on Alaska in 1993, and other companies have considerably reduced their Alaska presence, laying off hundreds of Alaska employees over the past several years. The energetic participation of new, independent companies in Alaska's economy should be encouraged, both for its own sake, and to send a clear message that Alaska welcomes active, involved newcomers.

Alaska State Legislature



Representative Joe Green

(District 1)

Sponsor Statement

HB 325 - Heavy Oil Royalty Holiday

HB 325 allows the producers of heavy oil to forgo the payment of royalty to the state on the first 450 barrels of heavy oil produced each day, for a period of five years. The heavy oil considered in this bill is a thick, tar-like hydrocarbon that is more difficult to produce than the lighter, more conventional oil and gas. The purpose of suspending the royalty is to encourage the lessees of heavy oil deposits to do field research and hopefully develop the maximum amount of recoverable oil in a timely manner.

HB 325 requires no application, the suspension is automatic. In order to receive the suspension the producer must simply submit documentation to DNR certifying that the oil produced meets the definition of "heavy oil" and monitor the production rate to satisfy the requirements in the bill.

HB 325 sends a message to potential investors world-wide that the 19th Alaska Legislature supports the development of heavy oil.

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. CSHB326(FIN)AM

Revision Date: Original Dept Affected Natural Resources
 Title: An Act authorizing suspension of payment BRU: Resource Development
of a portion of the royalty due the state for initial production... Component: Oil & Gas Development
 Sponsor: Representative Green
 Requestor: _____ Component Serial No. 439

Expenditures/Revenues		(Thousands of Dollars)					
OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02	
PERSONAL SERVICES							
TRAVEL							
CONTRACTUAL							
SUPPLIES							
EQUIPMENT							
LAND & STRUCTURES							
GRANTS, CLAIMS							
MISCELLANEOUS							
TOTAL OPERATING	00	00	00	00	00	00	
CAPITAL EXPENDITURES	00	00	00	00	00	00	
CHANGE IN REVENUES (1004)	((172.5/well)	((172.5/well)	((172.5/well)	((172.5/well)	((172.5/well)	((172.5/well)	

FUND SOURCE		(Thousands of Dollars)					
1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1006 GF/MHTIA							
Other							
TOTAL	00	00	00	00	00	00	

Estimate of any current year (FY96) cost: \$ none

POSITIONS		FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME		0	0	0	0	0	0
PART-TIME		0	0	0	0	0	0
TEMPORARY		0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

It is not possible at this time to accurately predict the number of new wells that will be drilled that will qualify for the proposed royalty suspension. Nor is it possible to accurately predict the timing of the drilling of any of these new wells. For each new qualifying well that is drilled, if it produces at a rate of 450 barrels per day and oil is valued for royalty purposes at \$10 per barrel, and the royalty is reduced from 12.5% to 2.0%, then the annual royalty suspension will be \$172,500 per year for each of the first five years of well life. Assuming that the well produces at the 450 b/d rate for five years and oil prices stay flat, the total royalty suspension would amount to \$862.5 per well. For a new demonstration project equal in size and scope to the existing Mine Point Schrader Bluff heavy oil project, the royalty suspension would range from \$1.25 million per year at current well rates to \$2.76 million per year at well rates of 450 b/d/well.

Long term production behavior also is unknown for these wells. It is suspected that the wells will produce at a fairly constant rate for at least five years then production decline will begin. Behavior of the Mine Point Schrader Bluff wells is being analyzed to determine if any production trends are evident to date.

Prepared by: Ken Boyd, Director of Oil & Gas Phone: 259-8800
 Division: Oil & Gas Date: 17-Apr-98
 Approved by Commissioner: [Signature] Date: 17-Apr-98
 Agency: Natural Resources

PREPARER TO PROVIDE ALL DISTRIBUTION COPIES TO GOVERNOR'S LEGISLATIVE OFFICE

The Relationship of HB 325 to the Three Categories of Royalty Relief Available Under HB 207

HB 207's Subsection A Relief--Encouragement of New Marginal Fields

This relief is authorized by AS 38.05.180(j)(1)(A) (as amended by HB 207). In one sense, this "Subsection A relief" serves the same purpose as HB 325--to encourage capital investment in new, marginal fields. However, Subsection A relief is available only if "the field or pool has not previously produced oil or gas for sale" AS 38.05.180(j)(1)(A)(ii). BP and OXY currently produce, and sell, about 3,400 bbls/day of Schrader Bluff oil from their Tract 14 pilot project, and Arco produced and sold West Sak Sands oil from its pilot project in the Kuparuk River Unit.

As a result, neither field is eligible for Subsection A relief.¹⁷

Subsection B Relief--Prolonging the Life of the Field

Relief is available under this subsection to "prolong the life of an oil or gas field" AS 38.05.180(j)(1)(B). Relief can only be granted under this subsection if the lessee demonstrates by "clear and convincing evidence" that field life will be prolonged, *and* the relief would be "in the best interests of the state."

Royalty relief on these grounds pre-dates HB 207, and the precedent established by Conoco and OXY's application to change the special royalty surcharge for Kuparuk Formation production from the Milne Point Unit--the only oil and gas royalty reduction application ever processed by DNR--illustrates how narrowly the agency has interpreted this type of relief.¹⁸

The first impediment to relief under this clause is time. Conoco first applied for Milne Point royalty relief in 1985, ushering in five years of administrative and legislative debates. Conoco and OXY reapplied for relief under the Milne Point Unit Agreement in 1990. DNR Commissioner Heinze denied those applications in April, 1991, and two years of subsequent litigation finally culminated in a 1994 settlement.

¹⁷ As OXY has said in the past, the possibility of discretionary royalty relief under HB 207 would not provide a sufficient capital investment incentive to spur further development of Schrader Bluff, even if OXY were eligible for it. The only point here is that the possibility of obtaining both this kind of discretionary relief and the automatic suspension of HB 325 doesn't exist, because Schrader Bluff is ineligible.

¹⁸ Conoco and OXY had applied to DNR, under a special relief provision in the Milne Point Unit Agreement, to amend the royalty provisions of that agreement--which included a 7.5% royalty surcharge above-and-beyond the 12.5% lease royalty. DNR, however, chose to decide the companies' requests under AS 38.05.180(j), which is the statute amended by HB 207.

While, after passage of HB 207, applications under Subsection B may not take nine years, neither does history suggest that they will be decided quickly

More of a barrier are the substantive limitations that DNR has placed on this type of relief. The first is the economic test--whether relief is necessary to "prolong the economic life of the field." DNR has defined this test as an "operating loss" test:

At some point in an oil field'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.

¹⁷ An operating loss test is a conservative benchmark, since it looks only to current operating balances, and disregards the question of whether the lessee has recouped, or will recoup, its capital investment. ¹⁸ And, in this regard, remember that the lessee must prove a future operating loss by "clear and convincing evidence." DNR has ruled that it is impossible for the lessee to make a "clear and convincing" showing except at the very end of field life. That's because, according to the agency, any economic analysis done earlier in a field's life would necessitate reliance on projections of future oil prices, and the resultant revenue estimates would be neither "clear" nor "convincing." *Recommended Decision* at 16.

Even were a lessee to surmount the economic test, the "best interest" test would remain. DNR has interpreted this test rather strictly, demanding, in quantifiable terms, a "net direct benefit to the state." *DNR Decision* at 1, emphasis added. Additional investment and/or revenues that will "clearly" and "convincingly" flow directly to the state as a result of the royalty relief must exceed the value of the royalties lost through the lower royalty rate. *Id.*, see also *Recommended Decision* at 15-16. Since lessees, at the very end of field life, will likely not be making considerable new capital investments even if relief is granted (but will merely be trying to hold on for a few more years), the state is likely to find a "net direct benefit" only if the lessee has demonstrated, clearly and convincingly, that a reduced royalty will prolong production past the field's natural otherwise economic life.

¹⁷ *Decision of the Commissioner of Natural Resources Regarding the OXY USA Inc. Application for Royalty Reduction on ADI 47433, 47434, 47437, 47438, and 28241 (Kuparuk Participating Area, Milne Point Unit)*, April 17, 1991 at 1 ("DNR Decision").

¹⁸ To the extent that DNR would consider the lessee's return on investment in granting relief under this subsection, DNR also decided, in the Conoco and OXY cases, that a lessee earns a reasonable rate of return if the rate at least equals the then-current return on risk-free 90-day U.S. treasury notes. *Recommended Decision of the Commissioner of Natural Resources Regarding the OXY USA Inc. Application for Royalty Reduction on ADI 47433, 47434, 47437, 47438, and 28241 (Kuparuk Participating Area, Milne Point Unit)*, December 28, 1990 at 10 ("Recommended Decision").

Subsection C Relief--Reestablishing Shut-in Production

One predicate to this relief is that the field must have been shut-in. Suspending oil production operations, and leaving the pads, wells and facilities in a condition amenable to resumption of production, is a rare event. It requires DNR approval, and--given the considerable cost of starting-up oil production anew--is not an action lightly taken. Indeed, we are aware of only two instances where oil production has been shut-in, and then later resumed: (1) Milne Point in the mid-1980's, and (2) South Middle Ground Shoal field, for one year in the 1990's.

Moreover, even in these unusual cases, the operator must still establish that royalty relief to reestablish shut in production would be "in the best interests of the state." This would require operators to clearly and convincingly demonstrate the same "net direct benefit" to the state that DNR has established as a condition to Subsection B relief.

* * *

It seems rather sensible to prohibit a lessee from obtaining relief both under HB 325 and HB 207's Subsection A, since both laws are aimed at essentially the same purpose--encouraging capital investment in new fields. Subsection B, however, is a different matter, and the legislature will plainly need to take a hard look at the interplay between that subsection and HB 325.

Suppose, for example, that HB 325 results in full development of the Schrader Bluff field. Beginning in year 6, that will result in considerable royalty income to the state that it would not have received but for HB 325. Assuming a field life of 20 years, the state would continue to receive that income--at a royalty rate of 12.5%--for at least the next 12-13 years. Royalty relief would not be available under Subsection B during that period, especially in light of DNR's decision in the Conoco case. *See discussion of Subsection B, above.*

Near the end of field life, however, the state may be convinced that Schrader Bluff's field life could be extended, say, from 20 to 22 years if, under Subsection B, royalties were reduced from 12.5% to 5%.⁷ Plainly, the state would yield a net direct benefit by gaining two additional years of royalty income, and in our view the legislature should consider retaining that flexibility in HB 325 itself.

⁷ The minimum royalty allowable under Subsection B is 3%. AS 38.05.180(1)(B)

DRAFT

Introduced by: Governmental Affairs
Date introduced: April 8, 1996
Date passed:
Date transmitted:

RESOLUTION 96-0408.2

A RESOLUTION BY THE GREATER FAIRBANKS CHAMBER OF COMMERCE SUPPORTING THE STATE OF ALASKA INCENTIVES FOR THE DEVELOPMENT OF NORTH SLOPE HEAVY OIL RESERVES.

WHEREAS, the production from Prudhoe Bay has declined over 40 percent and the total North Slope production has declined over 25 percent; and

WHEREAS, the North Slope contains in excess of 20 billion barrels of heavy oil; and

WHEREAS, the oil industry has spent in excess of \$250 million during the past 10 years to economically produce North Slope heavy oil.

NOW THEREFORE BE IT RESOLVED that the Greater Fairbanks Chamber of Commerce urges the State of Alaska to support (implement) incentives for the development of heavy oil on the North Slope.

PASSED on April __, 1996 by the Greater Fairbanks Chamber of Commerce Board of Directors.

DRAFT

This document is only a draft.

Barton S. LeBon	It does not represent any formal action of the	William J. Robertson
Chairman of the Board	Greater Fairbanks Chamber of Commerce	President/CEO

04/22/96

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SENATE RESOURCES

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HB 325

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04/22/96

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HB 325

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LOCATION: ANCHORAGE

CONFIRMATION H

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